CITY OF TUCSON ENERGY SOURCING STUDY

DRAFT REPORT

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prepared by

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

BBK
BEST BEST & KRIEGER LLP
ATTORNEYS AT LAW

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1.1 INTRODUCTION

The electric utility franchise agreement between the City of Tucson ("City") and Tucson Electric Power ("Tucson Electric Power" or "TEP") expires in April of 2026 after a 25-year term. As a result, the City is considering placing a ballot measure in November of 2025 to determine whether to renew the current franchise agreement. The City is also currently negotiating with TEP around terms for a franchise agreement renewal. In 2023, City voters rejected a similar ballot measure which would have extended the franchise agreement for 25 years.

As part of this decision-making process, City issued a solicitation in November of 2023 for qualified firms to provide professional, technical, and economic consulting services to the City to analyze various options to source 100% renewable power for the City of Tucson community. This initiative is part of the City's commitment to transition to a sustainable energy future and support the implementation of Tucson Resilient Together,[1] specifically Climate Actions:

- **E-3.2** ***Work with community advocates*** and other jurisdictions to co-form a community choice energy program or joint powers authority (JPA) to procure 100% renewable power for the City of Tucson;
- **E-3.3** ***Commission a feasibility study*** on the formation of a public power utility, ahead of TEP's franchise agreement expiration in 2025; and
- **E-3.4** ***Pursue solar service agreements*** (SSAs) or virtual power plant agreements (VPPAs) to meet the City's power needs for municipal operations.
- **E-4.2** ***Coordinate with electric utilities*** to install battery energy storage systems in City-owned buildings and carports with an emphasis on combined solar + storage for community -serving critical infrastructure
- **CR-1.1** ***Establish one or more resilience hubs***

GDS Associates, Inc. (GDS) has completed technical and financial feasibility studies for the creation of a public power utility and a community choice aggregation (CCA) (or community choice energy (CCE)) program, and GDS has conducted technical and market research on SSAs and VPPAs and indicated how these may be utilized by the City to meet municipal operations power needs – specifically achieving 100% renewable electricity supply. Also, GDS has assessed how microgrids, local groups of electricity generation sources throughout the City, can play a pivotal role in the City's clean energy transition. A summary of the results of these analyses are described below.

1.2 PUBLIC POWER UTILITY

The City of Tucson's electricity needs are served by TEP, the local investor-owned utility (IOU) service provider. TEP serves retail customers within the City (and outside the City) and owns and operates power generation stations, transmission line systems and distribution line systems both within and outside the City.

To determine the feasibility of creating a City of Tucson public power utility, GDS evaluated the portion of the TEP utility system that would be purchased, estimated the system fair market value (purchase price), and forecasted the costs to operate a public power utility. The analysis included an estimate of the investments required to physically separate the remaining TEP electric system from a City public power utility electric system. In addition, GDS determined assets and investments TEP has made on behalf of all customers, including TEP customers in the City who depart service from TEP, and calculated a price City public power utility customers must pay to hold

[1] City of Tucson. *Tucson Resilient Together Climate Action and Adaptation Plan.* February 28, 2023. Available at: https://climateaction.tucsonaz.gov/pages/caap

remaining TEP customers harmless from the departing customers. These are considered stranded costs. The financial analysis provides the cost of anticipated financing arrangements the City would need to purchase and operate the utility.

Based on the cost of operations, the feasibility assessment determined the customer retail rates that would be charged over a 20-year time horizon. If public power customer rates are equal to or less than forecast TEP rates, the public power utility is deemed feasible.

Key considerations in the determination of this feasibility included: low and high values of the TEP system to be purchased,[2] finance costs for the system purchase and capital investment using taxable and tax-exempt financing, and operating costs. Power costs for the new City public power utility were developed from wholesale markets. The power supply portfolio meets the City's goal of 100% renewable power supply for all City users by 2045. TEP system capital and operating costs are forecast based on their current rates and preferred power supply portfolio determined through their resource planning process. These are all described in further detail in the Public Power Utility Feasibility Section of this report.

Figure 1-1 below indicates the overall outcome of the public power utility feasibility showing that the projected City public power utility will achieve positive net operating revenues over a 10-year time horizon. The net revenues are maximized by setting City public power utility rates at least equal to projected TEP rates over time, or the City may lower public power utility rates to a desired level and reduce net revenues. The City public power utility rates cover the system purchase, legal and regulatory support, separation investment, financing, operations, power purchases, labor, administration and overhead, and escalation costs and achieves 100% renewable power supply by the year 2045.

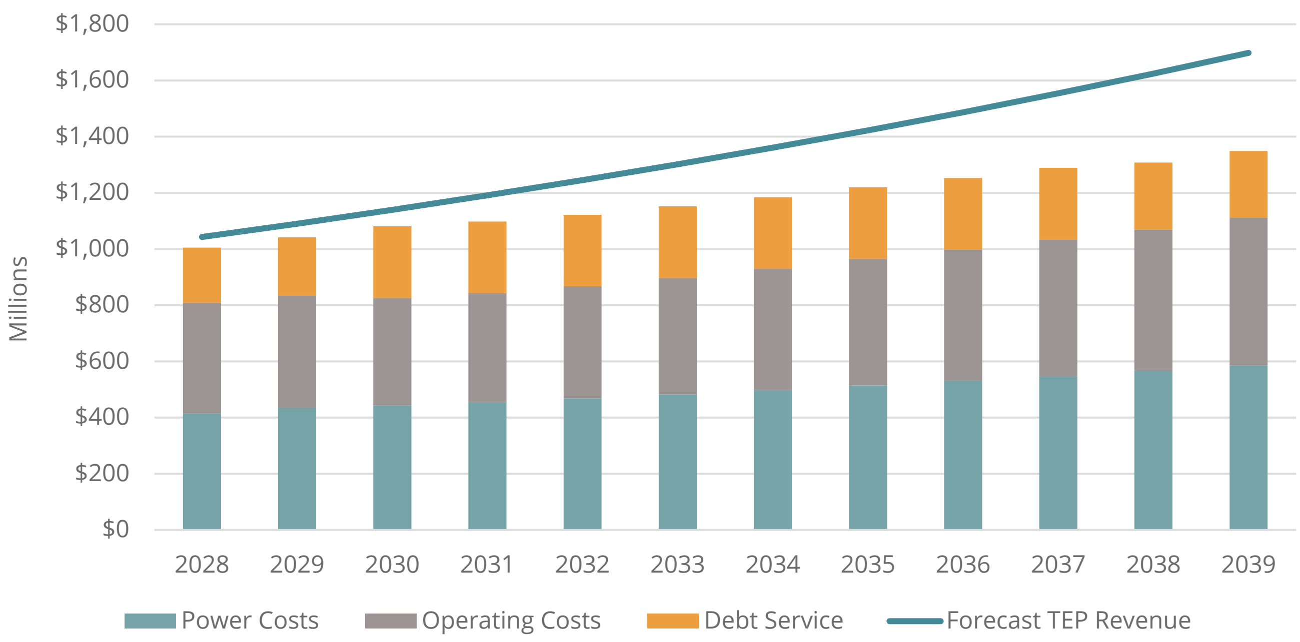

FIGURE 1-1. PUBLIC POWER 10-YEAR FEASIBILITY: TOTAL COST VS. REVENUE COMPARISON[3]

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[2] The system valuation was conducted using publicly available data, data from TEP, and generally accepted accounting principles for electric system valuation.

[3] Results in Figure 1-1 represent the highest valuation scenario for the system. This is the most conservative assumption for the purposes of demonstrating feasibility. Lower system fair market value would result reduce the public power utility costs and provide additional benefits to the City.

Finally, Figure 1-2 illustrates the potential ratepayer savings for residential customers. The savings potential depends on the fair market value of the plant (RCNLD = highest value and OCLD = lowest value). The lower market value results in lower costs for the public utility and lower rates to City ratepayers (greater savings).

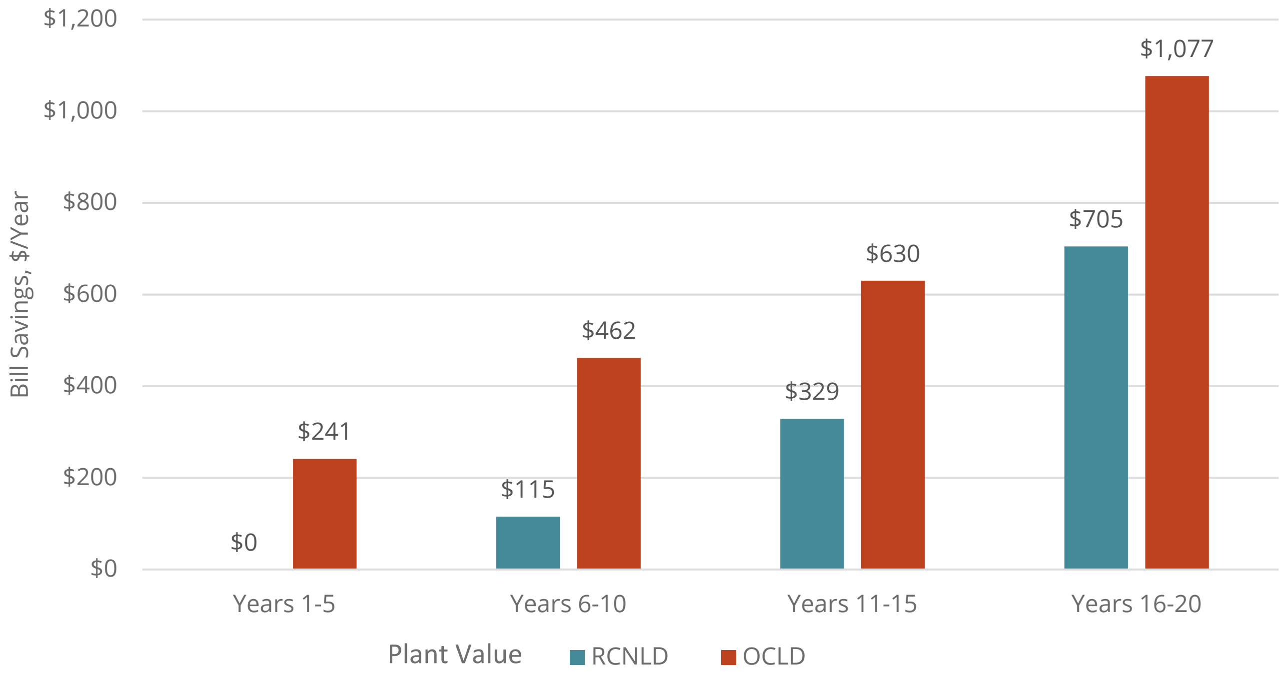

FIGURE 1-2. PUBLIC POWER AVERAGE ANNUAL RATEPAYER SAVINGS: RESIDENTIAL

While this feasibility analysis for a public power utility indicates promising outcomes, including forecasted lower customer rates and consistent positive net operating revenues throughout the evaluation period, pursuing and establishing a municipal utility entails significant risks and considerable effort. Ultimately it would require strong resolve and leadership from City officials.

Establishing the public power utility will necessitate substantial, additional due diligence as well as extensive engagement with TEP, potentially neighboring utilities, and other key stakeholders. It will also require the allocation of significant upfront capital for due diligence as well as the capital investment required to acquire TEP assets.

The likely opposition from TEP will also be a significant challenge. Creating a public power utility would redirect revenues currently received by TEP, prompting scrutiny and potential opposition. TEP may publicly highlight concerns about the City's operational readiness, infrastructure, resource adequacy, and leadership experience. These concerns could be broadly communicated to constituents, especially in advance of any public vote regarding the renewal of TEP's franchise agreement. The impact of potential TEP public outreach could shift the support from stakeholders such that the majority favor the current arrangement. Additionally, TEP may seek legislative or regulatory interventions to limit or delay the City’s efforts to establish its own public power utility.

While these risks are real, they are not insurmountable, and they must be carefully weighed and strategically managed as the City evaluates whether and how to proceed with establishing its own public power utility.

1.3 COMMUNITY CHOICE AGGREGATION

Community Choice Aggregation describes recent customer choice programs which have been legislatively authorized and implemented by various states throughout the country.[4] Under CCA, these states generally allow local governments (counties, cities, townships) to procure power for their residents instead of an incumbent IOU. The CCA program charges its customers retail rates that recover the program's costs. CCAs utilize the regional transmission systems and local distribution systems for power delivery and these functions are still performed by the IOU. CCAs have operated since the early 2000s. A handful of other states are considering legislation to authorize CCA. While CCA is not authorized in Arizona, local communities and interested stakeholders have expressed interest at the Arizona legislature.

A CCA program for the City of Tucson could be an alternative to achieving its goal of 100% renewable power supply and City-wide carbon neutrality by 2045. To implement a CCA in the City, the Arizona legislature must approve legislation allowing CCA formation and operation, and the Arizona Corporate Commission (ACC) would likely establish rules for CCA operation. The ACC had previously explored rules to establish competition in the Arizona electric utility market as early as 1996 and the state legislature fully opened the vertically integrated monopoly electric utility market to competition by statute in May of 1998 when the Electric Competition Act (ECA) was signed into law. However, a subsequent Arizona Court of Appeals decision in 2004[5] found some of the enabling regulations of the ECA to be unconstitutional and in 2022 the enabling language of the ECA that declared a competitive retail electricity market in Arizona and permitted the possibility of customer choice aggregation programs was removed from the Arizona Revised Statutes.

Despite the lack of enabling legislation and regulatory rules, this study presents a framework and feasibility analysis for Tucson that would be applicable for other, potential Arizona CCA programs. While the framework would be applicable to other areas in Arizona; however, the feasibility would be dependent upon the specifics of each IOU power provider. The City CCA would procure power for all program participants, just as it would under a City public power utility. The costs of procuring power over the forecasted time period for the public power utility are the same for the CCA. In addition, the costs to operate the CCA can be estimated based on best practices in other states. Due to GDS' experience in analyzing CCA feasibility for many jurisdictions, a detailed estimate of CCA non-power related operating expenses is provided. These costs include but are not limited to staffing, consultants, administration, and other overhead.

A key consideration in the determination of the City CCA is establishing the amount of stranded costs for remaining TEP ratepayers as described in the public power utility description above. In the case of a CCA, these stranded costs would be in the form of long-term power supply contracts held by TEP for City customers and generation plants owned and operated by TEP which were built to serve all TEP customers. GDS utilized publicly available information provided by TEP in their regulatory filings and current and projected power market prices to determine the amount of those stranded costs.

Just as for the City public power utility study, the necessary CCA rates were determined to cover all operating costs. If CCA rates were deemed lower than or equal to the TEP rates for power supply only, the City CCA is deemed feasible.

Figure 1-3 below indicates the overall outcome of the City CCA feasibility study showing that the projected City CCA will achieve positive net operating revenues over a 10-year time horizon. The net revenues, earned only on the power costs portion of the customer bill, are maximized by setting City CCA energy rates at least equal to

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[4] States include California, Illinois, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Ohio, Rhode Island and Virginia.

[5] *See Phelps Dodge Corp. v. Arizona Elec. Power Co-op., Inc.,* 207 Ariz. 95, 128, ¶ 152 (App. 2004), as amended on denial of reconsideration (Mar. 15, 2004) (failure of ACC to consider fair market value of alternative electric service providers and to set range of rates unconstitutional)

projected TEP rates over time. Or the City may lower CCA energy rates to a desired level and reduce net revenues. The City CCA rates cover all start-up, power purchases, financing, labor, administration and overhead, and escalation costs and achieves 100% renewable power supply by the year 2045. These benefits would be accomplished through either reduced retail electricity costs or community programs funded by CCA revenues.

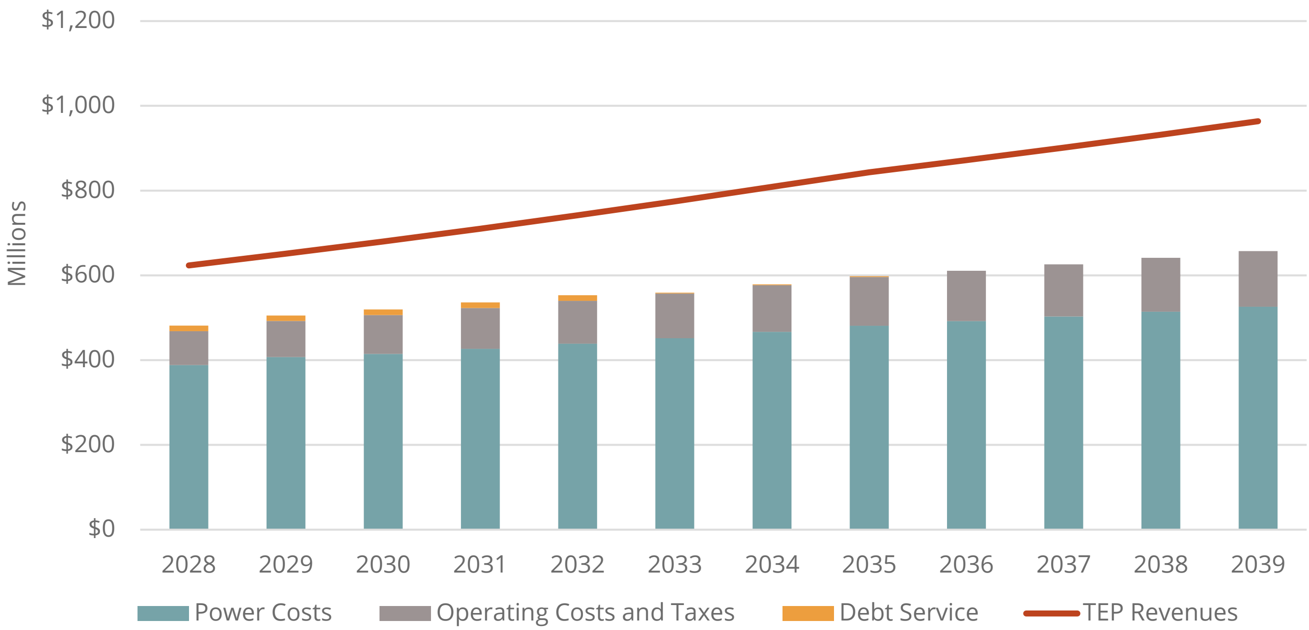

FIGURE 1-3. CCA PROGRAM 10-YEAR FEASIBILITY: TOTAL COST VS. REVENUE COMPARISON

Key statistics and program design characteristics of operating CCAs in other states are also described further in the CCA Section of this report. This information can be used by the City, other jurisdictions, and stakeholder groups in their further investigation or advocacy for CCA in Arizona. The economic feasibility outcomes found in this City CCA study may not be the same for other jurisdictions. Each jurisdiction would need to analyze its power supply costs and impacted IOU assets costs to determine CCA program feasibility. TEP's reaction to next steps by the City in potential CCA development will not be the same as described for municipalization. This is because CCA-enabling legislation does not exist in Arizona. Additionally, under CCA regulations from other states, IOU revenues are impacted much less when compared to the alternative of creating a public power utility. Should the Arizona legislature again address customer choice in its electric utility power supply industry, the details of how utilities will be impacted will be negotiated by interested parties.

1.4 SSA AND VPPA

As part of the City's objective to achieve 100% renewable power supply for municipal operations, the City is currently utilizing SSAs for renewable power generation at City-owned locations and is actively investigating utilization of VPPAs.

SSAs allow the City to install behind-the-meter solar energy systems on municipal rooftops, landfills, and other publicly owned properties. These systems directly offset a portion of the City's electricity use and require no upfront capital investment. With nearly 75 SSA systems installed and operating today, these facilities produce roughly 15% of the City's total municipal electricity consumption. SSAs offer a predictable, fixed energy rate to the City and visible proof of its commitment to clean energy. However, due to the City's ambitious development of SSA, most of the ideal locations have already been utilized which limits the potential for additional SSA deployments.

To offset other municipal energy needs that cannot be met via on-site solar, VPPAs would enable the City to support renewable energy development somewhere else in Arizona or other states while securing Renewable Energy Credits (RECs). These RECs, given the City's current standards and approach, count toward the City's sustainability reporting and emissions reduction targets.

To reach greater municipal renewable energy goals, the City can expand the number of SSA sites and contracts, pursue VPPAs, install battery storage onsite at SSA locations, and examine participation in TEP's Green Energy Tariff. This TEP program allows large energy users to purchase energy from new renewable projects, with varying levels of additionality and customization.

GDS evaluated the ongoing economic implications, duration and flexibility, environmental impacts, commercial availability, cost effectiveness, policy and legal considerations, and technical constraints of future, incremental utilization of SSAs, VPPAs and enrollment into TEP's Green Energy Tariff for achieving 100% renewable energy utilization for City municipal operations beyond its current 15% renewable energy utilization.

Table 1-1 below summarizes a comparison of the three different means of procuring renewable energy for City utilization.

TABLE 1-1. SUMMARY OF RENEWABLE ENERGY PROCUREMENT OPTIONS

Factor	TEP Green Energy Tariff	SSA	VPPA
Cost per kWh	$0.003-$0.02 above retail	11.7 cents	Variable (market)
Upfront Capital	None	None	None
Risk Exposure	Low	Low	Moderate-High
REC Ownership	Yes	Yes	Yes
Additionality	Depends on Option	Yes	Potentially
Location of Generation	Off-site (TEP territory)	On-site (City facilities)	Off-site (any U.S. grid)
Flexibility & Scale	Medium	Limited	High
Long-Term Cost Certainty	Medium	High	High

While all three options can contribute to meet the City's municipal operations objectives, it is recommended that the City continue its efforts to achieve carbon neutrality with these means and that it continually assess the optimal and most risk-adjusted cost-effective manner in which 100% renewable energy utilization may be achieved by each option. Such details to be further scrutinized include: potential, future changes to TEP tariffs; longevity of the TEP tariff terms and conditions; production capacities of potential SSA City locations and specific TEP site-integration restrictions; potential responses to VPPA solicitations for power and renewable energy credits issued by the City; and amount of renewable power and/or credits from available and planned VPPA providers and terms and conditions of potential VPPA providers.

1.5 MICROGRID

The City is evaluating microgrids, localized and integrated energy systems which may operate independently or alongside the traditional utility grid, to provide resilient, reliable, and sustainable power. Microgrids include renewable energy and energy storage systems, backup generation, and advanced control technologies to ensure continuous operation during outages and optimized overall energy usage.

The City's goals for microgrid deployment include enhancing community resilience, ensuring power reliability to critical facilities, increasing renewable energy use, and safeguarding vulnerable populations during extreme heat events.

Microgrids installed by the City, or other TEP customers, must adhere to TEP regulations and requirements for interconnection to the TEP grid. The City and TEP have already begun collaboration on a City microgrid installation at the City's Donna R. Liggins Recreation Center which has been through preliminary design involving both the City and TEP and is awaiting funding for implementation. TEP is presumed to have the capabilities to plan, develop, and integrate microgrids within complex operational environments.

GDS has reviewed maps of the City and identified potential microgrid locations for two categories of sites: critical infrastructure locations (including medical facilities, airports, military bases, government buildings, higher education campuses, utilities infrastructure) and community centers owned by the City which may serve as community cooling centers during high-temperatures and/or potential utility outages.

GDS has also developed microgrid sizing and cost estimates for example microgrid locations for a potential community cooling center (150 kW peak load) and a hospital campus (2 MW peak load) based on GDS' experience assisting clients develop microgrids at other client locations. Table 1-2 below summarizes the sizing and cost for these example installations. A critical factor in evaluating the financial viability of a microgrid is consideration of other direct and indirect costs of loss of power at these sites. Additionally, GDS has seen that generation installations, such as microgrids, provide system operation and planning benefits to utilities both for grid operations and power resource supply. Representative benefits to this utility integration of microgrid scenarios are shown. This synergy between the microgrid and broader utility infrastructure highlights significant potential cost savings and enhanced operational value achievable through strategic planning and integration. In most cases, battery storage used solely to support a microgrid during rare power interruptions within an otherwise highly reliable grid is not economically feasible or attractive. However, when the same battery system can also serve the larger grid as a capacity resource *and* function as a critical component of a microgrid to enhance the reliability of specific loads, its value and cost-effectiveness increase substantially.

TABLE 1-2. COMPARATIVE COST SUMMARY WITH AND WITHOUT UTILITY UTILIZATION:

Scenario	Community Cooling Center Cost	Hospital Critical Load Cost
Without Utility Integration	$1,155,000	$8,450,000
With Utility Integration	$462,000	$1,690,000

02 City of Tucson Background

The City of Tucson is located in Pima County and has a population of approximately 547,200.[6] Tucson is the second most populous city in the State of Arizona. Population growth has averaged nearly 1% per year since 2020. The climate is generally considered hot desert with two seasons: summer and mild winter. The average rainfall in Tucson is 10.6 inches per year generally occurring during the North American monsoon season in summer. Daily high temperatures during summer average near 100 degrees in the summer and 75 degrees in winter.

Major employers in/near Tucson include the University of Arizona, RTX Corporation (locally known as Raytheon) (aerospace and defense), Davis-Monthan Air Force Base, the State of Arizona, local school districts, Pima County, Banner University Medical Center, U.S. Customs and Border Protection, mining, and large retailers such as Walmart.

2.1 CURRENT ENERGY SUPPLY/SERVICE (TEP)

Tucson Electric Power currently provides electric service to businesses and residents within the City. TEP is a subsidiary of Fortis Inc. and is the third largest utility in Arizona. The utility employs approximately 1,500 people and serves over 450,000 customers in the Tucson metropolitan area. TEP's total service area covers 1,155 square miles. The utility operates a diverse energy portfolio, with an increasing focus on renewable energy sources; TEP's resource mix is approximately 20% renewable, 45% natural gas, 23% coal, and 12% unspecified (market purchases).[7] This energy mix is verified based on TEP's 2023 Edison Electric Institute Report.[8] TEP also operates several power generation plants, such as the Springerville Generating Station, and is investing in new technologies to advance its clean energy goals.

TEP plans to retire its two remaining coal plants by 2032 (approximately 900 MW from Four Corners and Springerville).[9] To replace these units and meet expected load growth, TEP plans to add renewable energy (mostly solar), short-term storage, and 400 MW of natural gas fired generation. TEP also recently announced that it was partnering with APS and Salt River Project (SRP) to explore nuclear generation. Because nuclear is not yet included in TEP's IRP as a preferred resource, this resource is not evaluated in this study. Overall, TEP plans to achieve carbon neutrality by 2050.

Currently TEP offers green tariff options (also discussed in Section 6.11of this report) for non-residential customers that wish to purchase renewable power supply at an additional cost. The three options under this tariff include:

1. ***Green Source.*** Purchase carbon-free energy from planned or existing TEP resources. Contract terms are for a period of 1 year.
2. ***Green Site.*** A multi-year agreement where customers purchase green power from a resource, or group of resources, located in a designated area or parcel.
3. ***Green Build.*** A partnership between participating companies and TEP to build new generation. This option requires long-term commitment.

The above options provide some additional flexibility for non-residential customers to purchase green energy supply at various risk profiles and contract terms.

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[6] City of Tucson population estimate for 2023 from the U.S. Census Bureau.
[7] 2023 TEP Energy Mix https://www.tep.com/our-energy-mix/
[8] It assumes that all sales for resale were sourced from coal or natural gas fired generation. See report section 4.10 for more detail. UNS Energy Corporation. Electric Company ESG/Sustainability Quantitative Information. June 2024. Available online: https://docs.tep.com/wp-content/uploads/TEP-EEI-ESG-2024.pdf
[9] TEP. 2023 Integrated Resource Plan available at: https://www.tep.com/2023-irp/

Not only is TEP a retail service provider, but it is also an energy Balancing Authority (BA). As a BA, TEP ensures that the power system and demand are balanced in real time throughout the balancing area. TEP is also responsible for maintaining operating conditions under the reliability standards issued by the North American Electric Reliability Corporation (NERC) and approved by the U.S. Federal Energy Regulatory Commission (FERC). A more detailed description of TEP's transmission and distribution systems are included in the City public power utility section.

2.2 CITY ENERGY GOALS

The City of Tucson has adopted a climate action and adaptation plan, Tucson Resilient Together,[10] which plans for carbon neutrality across City operations by 2030 and carbon neutrality community wide by 2045. In an effort to work towards those goals, the City recently began discussions with TEP for 100% GHG free energy supply across its operations (Green Source option). The contract would likely be for a 1-year term that would be renewed annually to maintain the renewable status for the City's power supply.

2.3 LOAD SUMMARY AND FORECAST

The electric load forecast is a key input to the feasibility analysis for the City public power utility and CCA options. TEP provided monthly energy use and number of service accounts within the City by rate class. Figure 2-1 shows the service account data for each rate class and Figure 2-2 illustrates the monthly retail sales for customers located within the City. In 2023, there were nearly 250,000 service accounts within the City compared with over 440,000 total retail customers served by TEP.[11] Total annual sales in 2023 were 4,908 GWh, or 46% of total TEP retail sales.

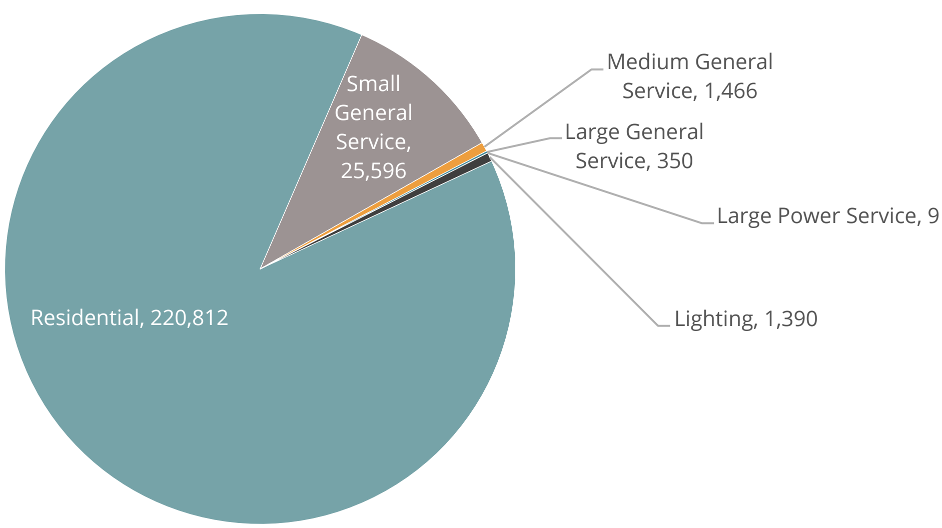

FIGURE 2-1. 2023 SERVICE ACCOUNTS IN CITY OF TUCSON

[10] City of Tucson. *Tucson Resilient Together Climate Action and Adaptation Plan.* February 28, 2023. Available at: https://climateaction.tucsonaz.gov/pages/caap

[11] Total TEP customer count is from TEP's 2023 FERC Form 1.

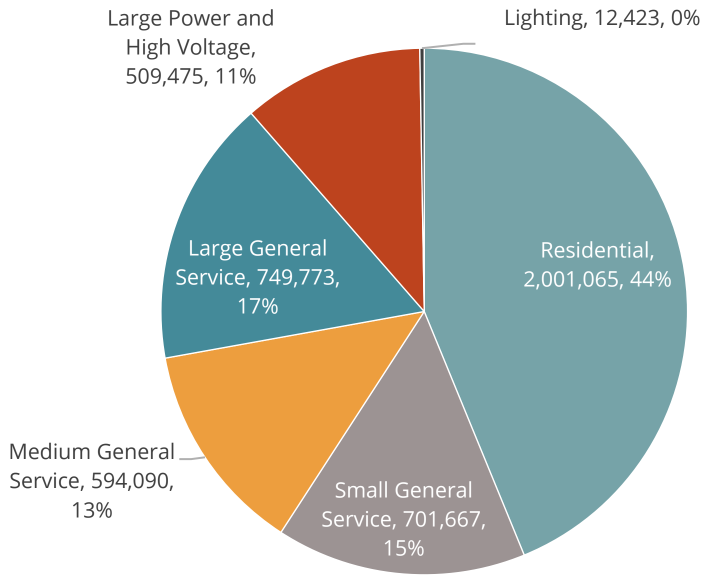

FIGURE 2-2. 2023 RETAIL SALES IN CITY OF TUCSON, MWH

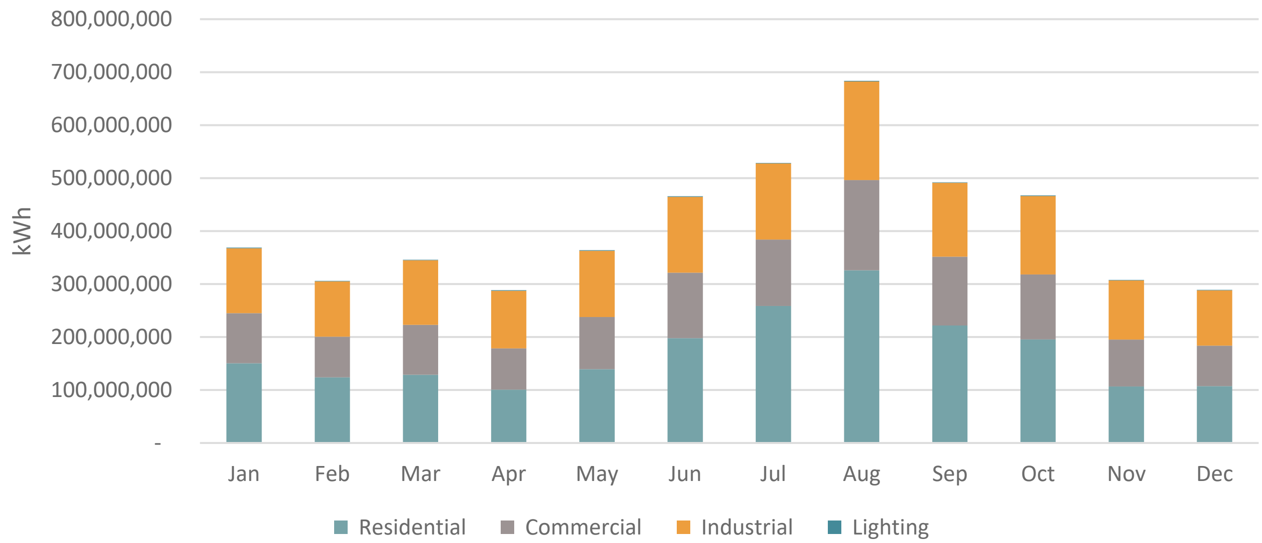

FIGURE 2-3. 2023 MONTHLY RETAIL SALES

The monthly retail sales are shaped based on hourly load profile data obtained from the Energy Information Administration for residential homes in Arizona.[12] Non-residential load profiles are estimated using hourly data from commercial and lighting customers in a similar climate zone.[13] Combined, these profiles are summarized in

[12] U.S. Department of Energy. Tucson hourly loads: USA_AZ_Tucson.Intl.AP.722740.TMY3_Base.xlsx. Updated June 19, 2024. Available at: https://catalog.data.gov/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-state-bbc75

[13] Southern California Edison 2024 Dynamic Load Profiles for GS-1, GS-2. https://www.sce.com/regulatory/load-profiles/dynamic-load-profiles and 2025 static load profiles for street lighting. https://www.sce.com/regulatory/load-profiles/2025-static-load-profiles

Figure 2-4 and Figure 2-5 for summer and winter respectively. These profiles are utilized for the power supply cost forecast for the City public power utility and CCA options.

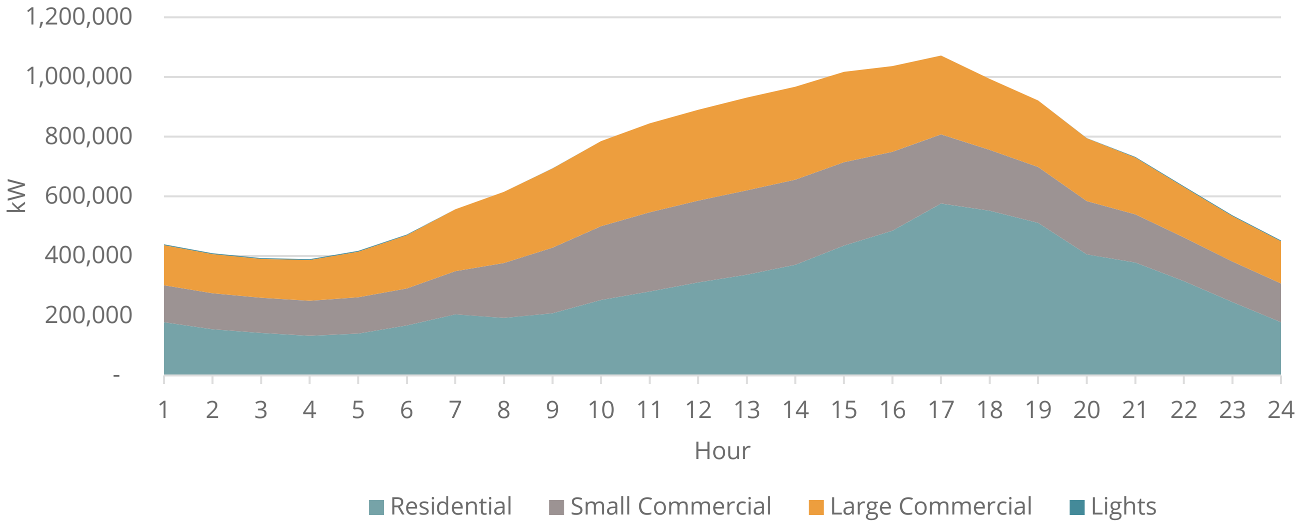

FIGURE 2-4. CITY/MUNICIPAL SUMMER WEEKDAY LOAD PROFILE

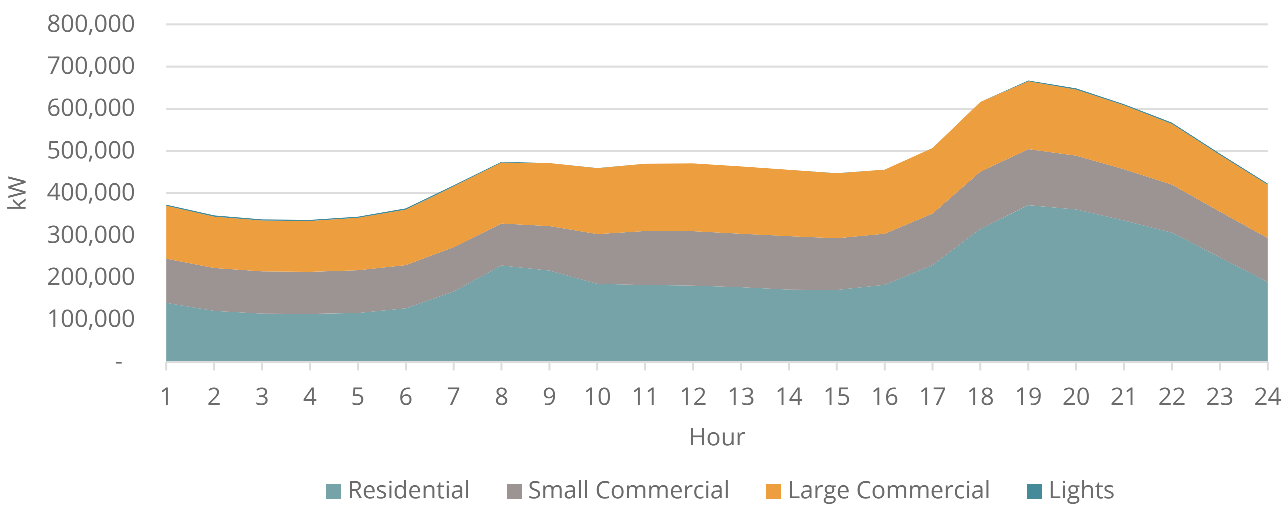

FIGURE 2-5. CITY WINTER WEEKDAY LOAD PROFILE

TEP projects load growth primarily for peak demand use with little to no growth in energy sales.[14] The forecast for the City follows the same assumptions TEP adopted in its IRP through 2040. The result is an average annual energy growth of 1.5%. This forecast is extended beyond 2040 assuming a 1% annual growth rate. Figure 2-6 illustrates the electric load forecast for residents and businesses located within the City.

[14] TEP 2023 IRP

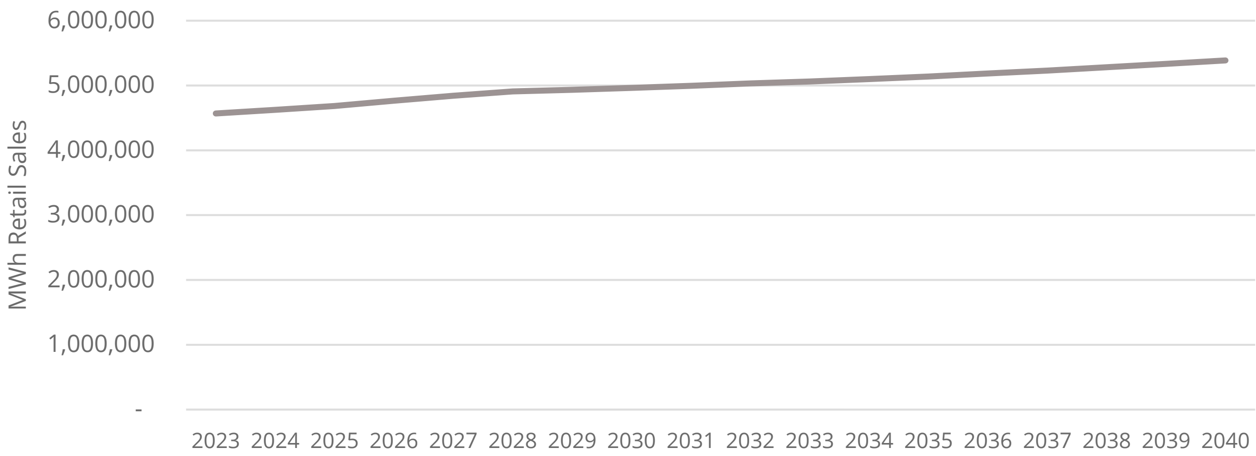

FIGURE 2-6. ELECTRIC LOAD FORECAST: CITY OF TUCSON

TEP's load forecast is based on expectations for energy efficiency savings, economic development, electric vehicle adoption and behind-the-meter solar adoption. With regard to electric vehicle adoption, TEP forecasts over 200% growth year over year in adoption.[15] TEP expects that adoption will result in over 46,000 EVs within Pima County by 2030. This adoption rate is accelerated compared with EV adoption expectations for other parts of the US primarily due to lower-than-average initial penetration in Arizona. Since the 2023 IRP was published, EV registrations have tripled in the state.[16] This is consistent with the high adoption rate anticipated by TEP.

[15] TEP 2023 IRP Appendix G page 2.

[16] Iruoma,Kelechukwu. Cronkite News. Number of electric vehicles in Arizona outpacing State's charging stations. October 18, 2024. Available online: https://tucson.com/news/state-regional/government-politics/number-of-electric-vehicles-in-arizona-outpacing-states-charging-stations/article_c9b9d4b3-bf54-59ad-a5bb-13bcb498464d.html

03 Public Power Utility Feasibility

3.1 FEASIBILITY FRAMEWORK/METHODOLOGY

The feasibility assessment is prepared from the perspective of the potential new public power utility. Costs and revenues are evaluated for the public power utility and for future ratepayers. The expense estimates cover the total cost of doing business for the City public power utility. The public power utility is deemed financially feasible if the analysis meets the following criteria:

1. The expected rates charged by the public power utility both recover the utility's expenses and also do not exceed the expected rates charged by TEP.
2. Customers that remain with TEP are not negatively impacted from the City's public power utility operations.
3. All impacted taxing districts are made whole.

In addition to the feasibility criteria, the analysis evaluates accelerating the renewable content of the City's electric supply. Finally, a side analysis is prepared for specific benefits related to carbon impacts of the City's power portfolio that reaches greenhouse gas neutrality sooner compared with TEP's current plan.

3.2 PUBLIC POWER UTILITY FUNCTIONS

Functions provided by electric utilities vary. Many investor-owned utilities are vertically integrated providing production (energy generation), transmission, and distribution. The proposed municipal utility would be a generation and distribution utility only. The analysis assumes that TEP would retain the majority of its transmission assets, and the public power utility would purchase transmission from TEP from its standard tariffs. The public power utility would, acquire, own and operate the local distribution system, provide customer service and billing, and acquire the power supply needed to serve customers through agreements or project ownership. Figure 3-1 below summarizes who would provide service to electric customers in the City of Tucson when a public power utility is formed.

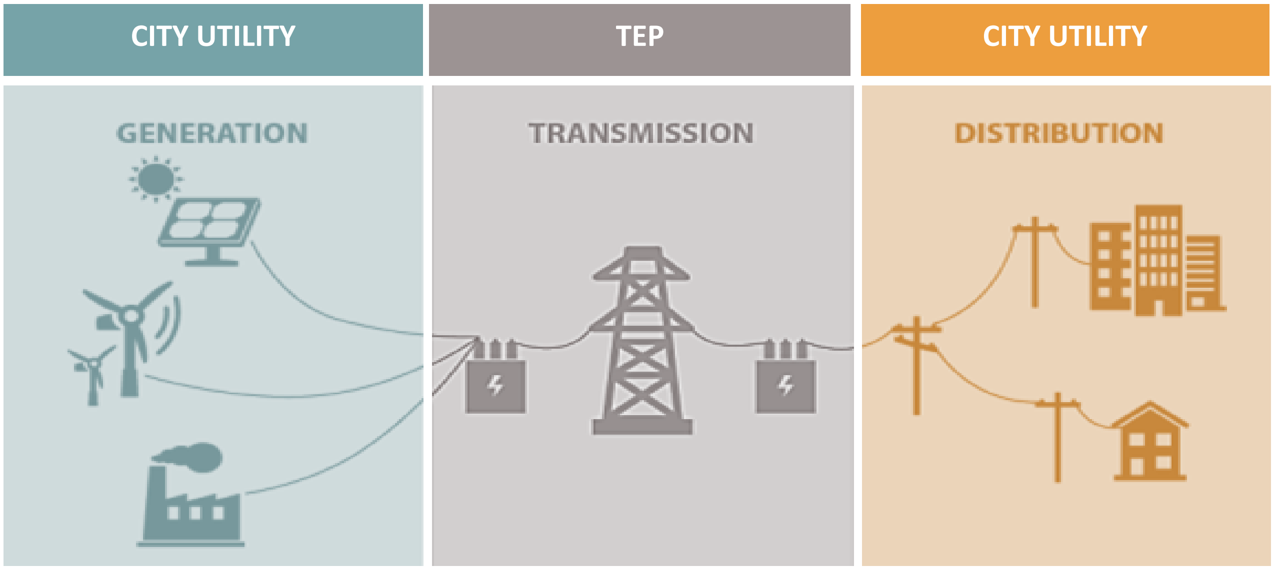

FIGURE 3-1. ELECTRIC UTILITY FUNCTIONS

3.2.1 Benefits and Challenges of Public Power

Public power includes municipal utilities, electric cooperatives, and utility districts. Public power can have many benefits to local residents and businesses. On average, electric rates for customers taking service from public utilities are lower compared with service from investor-owned utilities.[17] From a practical perspective, public utilities often have lower rates due to the following:

1. Public utilities are non-profit entities that do not pay dividends to shareholders.
2. In some regions public power utilities have better access to low-cost, public power supply. Examples include power supply from the Nation's federally-owned hydroelectric facilities.
3. Public borrowing rates are non-taxable, reducing the cost of capital investments for public utilities.
4. Generally, public power utilities are less regulated by state utility commissions. In cases where regulation persists, there is often a carve-out for smaller sized utilities or publicly owned utilities reducing the burden of compliance cost.

Conversely, public power entities are smaller in size on average compared to their IOU counterparts. Some utilities are small enough that aged infrastructure coupled with mismanagement of rate collection, and diminished economies of scale can create difficulties and in some cases rate shock for ratepayers as the utility responds to required plant investment or industry evolution. There is also greater risk that new regulations will significantly impact small utility rates. Larger public utilities, such as the potential City of Tucson public power utility, are more able to respond to changes in regulatory requirements, manage capital replacement, advocate successfully for public power customers, and spread costs across customers fairly and equitably.

The challenge of new public power (municipalization) primarily lies in establishing new entities where the incumbent utility is an IOU. Investor-owned utilities are not always willing to sell portions of their service area. Therefore, the process of municipalization can be costly and time consuming. Examples of successful and unsuccessful/attempts are provided in the next section.

3.3 SUMMARY OF PREVIOUS MUNICIPALIZATION ATTEMPTS/SUCCESS

Forming a municipal utility where service is currently provided by an IOU has been shown to be challenging. In our experience, successful implementation of public power is relatively rare, often hindered by a combination of political resistance, lack of sustained leadership commitment, difficulty securing the necessary financial and legal resources, and strong opposition from the incumbent utility. The American Public Power Association (APPA) reports that a total of 50 public power utilities have been formed in the last 30 years.[18] Only 12 of these have occurred in the past 20 years. A few case studies are summarized in the tables below.

[17] American Public Power Association. 2025 Statistical Report. Page 10. Available at: https://www.publicpower.org/system/files/documents/2025-Public-Power-Statistical-Report.pdf

[18] https://www.publicpower.org/system/files/documents/municipalization-successful_public_power_campaigns.pdf

TABLE 3-1. SELECT SUCCESSFUL PUBLIC POWER FORMATION

Public Entity	Incumbent Utility	Years from Vote to Service	Dates	# Customers
Jefferson County, WA	Puget Sound Energy	4	2008-2013	18,000
Winter Park, FL	Florida Power Corp.	6	1999-2005	13,750
Hermiston, OR	Pacific Power (PacifiCorp)	4	1997-2001	4,900
Long Island Power Authority	Long Island Lighting Co.	12	1986-1998	1,035,000
Clyde, OH Light & Power[19]	Toledo Edison	2	1987-1989	2,600
Emerald People's Utility District, OR	Pacific Power	5	1978-1983	20,000

TABLE 3-2. UNSUCCESSFUL/IN PROGRESS PUBLIC POWER EFFORTS

Public Entity	Incumbent Utility	Active Investigation	Detail
City of Boulder, CO	Xcel	2010-2020	Ceased Efforts after 2020 Election
City of Pueblo, CO	Black Hills Energy	2018-ongoing	Ballot Vote 2020: 74% against municipalization Next ballot vote Scheduled May 2025
City of San Francisco, CA	Pacific Gas & Electric	2019-ongoing	Purchase price offer not accepted by incumbent utility. The CA Public Utilities Commission is reviewing the fair market value
City of Chicago, IL	Commonwealth Edison	2019-2020	Feasibility Study predicted higher rates
City of San Diego, CA	San Diego Gas & Electric	2021-ongoing	Phase 1 analysis completed Summer 2023, Phase 2 study in progress

3.3.1 Keys to Successful Municipalization

The American Public Power Association (APPA) offers a variety of resources to assist cities evaluating the formation of a municipal electric utility. While each municipalization effort is shaped by its own legal, economic, and political context, successful initiatives tend to share several core strategies and conditions:

- ***Broad Public Awareness and Education:*** Policymakers, stakeholders, and the general public were thoroughly educated on the advantages of public power—such as local control, rate stability, reinvestment in the community, and improved reliability. Effective public outreach and transparent communication helped build trust and support for the transition.
- ***Strong Community and Business Leadership:*** Municipalization efforts often gain momentum when supported by respected civic leaders, advocacy groups, and local businesses. Their endorsements can help drive political will and public enthusiasm, particularly when the effort is positioned as a long-term investment in the community's future.
- ***Securing Financial Resources:*** The city was able to develop a credible financial plan, including identifying funding sources for the acquisition of utility assets and startup costs. This may involve issuing municipal bonds, leveraging public-private partnerships, or structuring phased investment strategies.

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[19] https://clydeohio.org/DocumentCenter/View/360/The-Clyde-Electric-Story?bidId=

- ***Persistence in the Face of Resistance:*** In instances where the incumbent utility declined to voluntarily sell its assets, the municipality demonstrated the legal and political resolve to pursue acquisition through eminent domain. This often requires years of legal proceedings, expert testimony, and unwavering public support.
- ***Robust Legal and Technical Expertise:*** Successful efforts typically engage experienced legal, engineering, and financial advisors early in the process. These experts guide feasibility studies, asset valuation, operational planning, and negotiations with the incumbent utility.
- ***Early Planning for Operational Transition:*** Cities that successfully municipalize begin planning for day-one operations well in advance, including workforce recruitment, utility governance, customer service platforms, and integration with existing infrastructure. Many partner with nearby municipal or cooperative utilities during the transition period.

Municipalization is a complex and resource-intensive endeavor, but when approached strategically, it can yield lasting benefits for local communities.

3.4 MUNICIPALIZATION IN ARIZONA

This section discusses the process and requirements that the City would need to follow in forming a municipal electric utility, including acquisition by purchase or condemnation of the facilities and associated property rights of the incumbent IOU, Tucson Electric Power.

3.4.1 Tucson Has the Authority to Create a Municipal Utility and May Do so with Bond Financing

Arizona law allows the City to form a municipal electric utility to serve customers both within and outside of its corporate limits.[20] The City may purchase or condemn real property (*e.g.*, fee-owned land, easements) and personal property (*e.g.,* TEP's electric distribution facilities) for this purpose.[21] The City's right to purchase or condemn TEP's property[22] extends beyond its corporate limits[23] and the City may use the property it acquires for utility rights-of-way and to "establish, lay and operate a plant [and] electric line" for a municipal utility.[24] In addition, the City's franchise agreement with TEP contemplates that the City can purchase or condemn TEP facilities in lieu of renewing the agreement, which expires in April 2026.[25]

The City may, for any and all purposes provided for in A.R.S. § 9-511, "issue and sell bonds bearing interest not to exceed nine percent per annum."[26] The City may not issue tax-exempt bonds to acquire electric utility assets from the IOU.[27]

[20] A.R.S. Const. Art. 13 § 5; A.R.S. § 9-511(A); A.R.S. §§ 9-521 - 9-522.
[21] A.R.S. § 9-511(A).
[22] Tucson has been granted the power of eminent domain by means of its charter, A.R.S. § 9-511, and §§ 9-516, 12-111, and 12-1112. *Citizens Utilities Water Co. v. Superior Court In and For Pima County,* 108 Ariz. 296, 497 P.2d 55 (1972).
[23] A.R.S. § 9-522(A)(1).
[24] A.R.S. § 9-511(C).
[25] Ordinance No. 9429, Sec. 23.
[26] A.R.S. § 9-512(A).
[27] 26 U.S.C. 141(d). As an alternative to issuing bonds, a city may "lease at a stipulated rental a public improvement or utility." A.R.S. § 9-513.

3.4.2 The Process for Forming a Municipal Utility Under Arizona Law

A. ***Obtain Voter Approval***

Prior to constructing, purchasing, acquiring, or leasing any plant or property devoted to public utility services, the City must be authorized to do so by a majority of the voters at a general or special municipal election.[28] Tucson may also satisfy the voting requirement by holding a bond election to finance the acquisition of the utility plant and property.[29]

B. ***Purchase and Take Over Utility Property and Plant***

Tucson must also "purchase and take over" TEP's property and plant, including TEP's certificate of convenience and necessity (CC&N), before establishing its own municipal utility.[30] TEP's property and plant will become the City's property upon payment of the fair valuation within 18 months after the value is determined. The valuation amount is determined by one of the following methods:

- By agreement between the City and TEP;
- By arbitrators chosen in a manner agreed upon at the time by the City and TEP; or
- By a court of competent jurisdiction determining the compensation for the taking of TEP's property for public use in the manner described below. The City and TEP retain the right of appeal of any valuation so determined.[31]

3.4.3 Acquisition, Condemnation and Valuation

The City must attempt to purchase TEP's facilities. If TEP rejects the City's offer, the City would need to exercise its right of eminent domain by filing an action for condemnation in the superior court in the county in which the property is located. The following is an outline of the general eminent domain process, including the statutory prerequisite to submit a written offer to TEP.

Step 1 – Submit a Written Offer

The City must submit a written offer to purchase TEP's property and to pay just compensation for the same at least 20 days before filing an action for condemnation. The proposed compensation amount must include the value of any compensable damages to TEP's remaining property and be supported by one or more appraisals.[32]

Step 2 – Post Notice

The City must post notice of the offer and appraisal(s) in plain sight at the property that may be subject to condemnation at least 20 days before filing the condemnation action.[33]

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[28] A.R.S. § 9-514(A).

[29] *Desert Waters, Inc. v Superior Court In and For Pima County,* 91 Ariz. 163, 370 P.2d 652 (1962). *See also,* A.R.S. §§ 9-521 - 9-540 giving cities the ability to acquire utilities by eminent domain and to issue bonds to finance the cost upon a majority vote at a bond election.

[30] A.R.S. § 9-515. *City of Casa Grande v. Arizona Water Co.,* 199 Ariz. 547, 20 P.3d 590 (App. Div.2 2001), explaining that a city already being served by a public utility must first purchase and take over that utility before it may establish its own, and *Sende Vista Water Co., Inc. v. City of Phoenix,* 127 Ariz. 42, 617 P.2d 1158 (App. Div.1 1980), explaining that a city's acquisition of a public utility must include that utility's certificate to provide service in the area to be served by the municipal utility.

[31] A.R.S. § 9-515(B), (C) and (D).

[32] A.R.S. § 12-1116(A).

[33] A.R.S. § 12-1116(B). This requirement applies "if no lease is recorded or if more than one lease is recorded for the property with the county recorder."

Step 3 – File and Serve the Complaint

The City may exercise its right of eminent domain by instituting an action pursuant to the condemnation statutes with the filing of a complaint in the superior court in which the property is located.[34] The complaint must set forth, among others, the location and general routes of rights-of-way and descriptions of each piece of land sought to be taken.[35] The City must serve the complaint pursuant to Arizona's rules of service. Filing of the complaint will institute a proceeding in which the court or jury shall ascertain and assess the compensation to be paid for the City's taking of TEP's plant and property.[36]

Step 4 (Optional) – Request for Immediate Possession

At the time of filing its condemnation action, or any time thereafter, the City may apply to the court for an order permitting the City to take possession of and use the property that is the subject of the condemnation proceeding.[37] Possession may not be had until the City deposits money or posts a bond with the clerk of the court or the state treasurer in the amount of the probable compensation amount, as determined by the court at the hearing described immediately below.[38] The actual value of TEP's property will be determined at trial and shall draw interest at the legal rate from the date the compensation is fixed by the court or jury.

Step 5 – Hearing to Determine Probable Damages

The court will set a time for hearing upon receipt of the City's complaint and serve notice of the same on the parties in interest. On the day of the hearing, and if it appears to the court that the use for which the property is sought to be condemned is a necessary use, the court will receive evidence as to TEP's probable damages and may issue an order allowing the City to take possession and make full use of the property upon depositing money or posting a bond.[39] The City and TEP may also stipulate to the deposit amount, subject to court approval.[40]

Step 6 – Trial to Ascertain and Assess Compensation

Actions for condemnation are brought as other civil actions and must proceed in accordance with the condemnation statutes.[41] The court or jury in the condemnation action will ascertain and assess the compensation to be paid for the taking of TEP's plant and property and the City must apply to the court for an order permitting it to take possession of the same when it pays the amount determined in the condemnation proceeding to the court.

3.4.3.1 Compensation For Taking Plant and Property

The City will need to compensate TEP for (i) the fair and equitable value of TEP's plant and property, including its value as a going concern, and (ii) the actual and consequential damages, if any, TEP sustains by reason of the severance of the condemned property from TEP's remaining plant and property.[42] Reproduction cost new depreciated is one standard method for determining the current value of utility assets.

Arizona courts have been less clear or consistent in defining and assessing the "going concern" value. The basic idea being that condemning utility assets differs from condemning, for example, commercial buildings, where "the

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[34] A.R.S. § 12-1116(A).
[35] A.R.S. § 12-1117.
[36] A.R.S. § 9-518.
[37] A.R.S. § 12-1116(E).
[38] A.R.S. Const. Art. 2, § 17. A.R.S. § 12-1116(H), (I), (J), and (K).
[39] A.R.S. § 12-1116(H).
[40] A.R.S. § 12-1116(M).
[41] A.R.S. § 12-111 *et seq.*
[42] A.R.S. § 9-518(B).

business would not be destroyed since it could be moved to another location."[43] Ultimately, the "going concern" value will be determined by the court or jury based on evidence presented at trial. The allowance of nine (9) percent of the value of the utility's physical properties has been upheld as "not unreasonable."[44]

Regardless of how the court assesses the value of the business as a "going concern," the City's compensation to TEP must reflect the value of its certificate to do business (*i.e.*, it's CC&N), which value may be reached by considering TEP's Arizona Corporation Commission ("ACC") authorized rate of return on "used and useful" (*i.e.* "rate-based") assets.[45]

3.4.3.2 Payment is Due Within Six Months

The City has six months after a judgment becomes final following appeal, or within six months after the expiration time to appeal, to pay the amount determined to the court. To receive the funds, TEP files a satisfaction of judgment. If the City fails or refuses to pay the amount of the judgment to the court by the six-month deadline, the court will vacate the judgment, dismiss the complaint and find in favor of TEP.[46]

3.4.3.3 Supplemental Judgment for Improvements

To account for "additions, betterments, improvements, or extensions" ("Improvements") that TEP makes to its facilities during the condemnation proceeding, TEP must file a verified report under oath within thirty days of a final judgment showing actual amounts spent on such Improvements.[47] The Improvements could include items such as good faith or ACC-ordered maintenance expenses, distribution line extensions, previously-scheduled upgrades and replacements, etc. TEP's initial report must include a forecast of amounts it will be required to incur for the subsequent six months and TEP must file supplemental reports every thirty days thereafter until the City pays the amount of the judgment (*i.e.,* the "just compensation") into the court. The court will hold an additional hearing to verify and set forth in an order the amount the City must pay to TEP for any verified Improvements, payment being due within 90 days after the judgment is deemed final, or after the expiration of the time allowed for appeal if no party appeals.[48]

3.4.3.4 Other Issues to be Considered on Determining Compensation

The City may, for any and all purposes provided for in A.R.S. § 9-511, "issue and sell bonds bearing interest not to exceed nine percent per annum."[49] The City may not issue tax-exempt bonds to acquire electric utility assets from the IOU.[50]

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[43]*City of Phoenix v. Consolidated Water Co.,* 101 Ariz. 43, 415 P.2d 866 at 868.
[44] *Id. at* 871.
[45] *See City of Tucson v. El Rio Water Co.,* (1966) 101 Ariz. 49, 415 P.2d 872, in which the court said the certificate's value may be reached by considering the income which would probably be earned by the tangible property of the water utility's plant and it would not question whether the earnings are justified, because that matter is exclusively within the domain of the ACC.
[46] A.R.S. § 9-518(D). Additionally, if the complaint is dismissed for these reasons, the City may not institute another action in court to acquire the same plant and property or any portion thereof within three years of such dismissal. *Id.* at (K).
[47] A.R.S. § 9-518(E).
[48] A.R.S. § 9-518(I) and (J).
[49] A.R.S. § 9-512(A).
[50] 26 U.S.C. 141(d). As an alternative to issuing bonds, a city may "lease at a stipulated rental a public improvement or utility." A.R.S. § 9-513.

3.4.4 Arizona Corporation Commission Jurisdiction Over Municipal Utilities

The ACC's jurisdiction over municipal utilities is extremely limited and in the context of Tucson's consideration of forming a municipal electric utility, effectively nonexistent.[51] The City's right to municipalize retail electric utility service is enshrined in the Arizona Constitution,[52] provided for by law,[53] and well documented in myriad legal precedent. The ACC cannot prevent the City from forming a municipal electric utility and plays only a tangential role in the process for condemning public utility assets.[54] Moreover, the ACC cannot require TEP to seek its approval of the City's condemnation of TEP property and plant (or CC&N, or any portion thereof).[55] The ACC lacks jurisdiction over municipal utilities in other important areas, too. Concurrently, the Arizona Corporation Commission (ACC) may not grant a new CC&N or franchise to any entity to provide the same kind of public utility service previously authorized, unless Tucson "refuses to provide utility service to a portion or part of the area or territory previously authorized to" TEP.[56]

3.4.5 The ACC Lacks Ratemaking Authority Over Municipal Utilities

Municipal utilities in Arizona fix their own rates for service and may impose other fees and charges.[57] The ACC has no ratemaking authority in this respect.[58] Conversely, municipal utilities maintain broad ratemaking authority, subject to two notable exceptions. First, a municipality using bond financing must fix its rates "as nearly as practicable" to pay the interest and not less than 3% per annum on the principal of the bonds, in excess of maintenance and operation expense.[59] Second, a city must have a reasonable basis for charging nonresidents more for utility services than it charges its own residents.[60] Otherwise, the city is free to set its own rates for municipal utility service.

3.4.6 Tucson's Municipal Electric Utility Would Not Be Subject to Renewable Energy, Resource Planning, or Resource Adequacy Requirements

A Tucson municipal electric utility would not be subject to state mandates for renewable energy resources, integrated resource planning, or resource adequacy (RA). Current regulations require public service corporations[61] to satisfy an annual renewable energy requirement (as a percentage of retail electric sales) by obtaining renewable

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[51] The ACC's primary responsibilities include prescribing just and reasonable rates and charges to be made and collected by public service corporations and making reasonable rules, regulations, and orders, by which such corporations shall be governed in the transaction of business within Arizona. Municipal corporations are excluded from the definition of public service corporations. A.R.S. Const. Art. 15 §§ 2. 3. Generally speaking, the ACC does not have jurisdiction over municipal utilities, with the notable exception of pipeline safety for municipal gas utilities. *See* https://azcc.gov/utilities. The ACC may however issue a new CC&N or franchise to a public utility to provide utility service in any portion of a municipal utility's service area previously served by a public utility if the municipal corporation refuses to provide service in that area. A.R.S.§ 9-516(D).
[52] A.R.S. Const. Art. 13 § 5.
[53] *Inter alia,* A.R.S. §§ 9-511 and 9-522.
[54] As noted above, the "going concern" value for which a municipality would need to provide compensation to a public utility may be based in part on the value of the public utility's ACC-issued CC&N and related authorized earnings.
[55] *See City of Surprise v. Arizona Corporation Commission*, 437 P.3d 865, 874.
[56] A.R.S. § 9-516(D).
[57] The municipality's power to adopt fees is necessarily implied in its right to own and operate public utilities. *Mountainside MAR, LLC v. City of Flagstaff,* 253 Ariz. 448, 73 Arizona Cases Digest 23, 514 P.3d 948 (App. Div.1 2022), review denied.
[58] The legislature alone has the right to regulate rates charged by a municipality operating a public utility and it has plenary power in that respect except as limited by the Constitution. *City of Phoenix v. Kasun,* 54 Ariz. 470, 97 P.2d 210, 127 A.L.R. 84 (1939).
[59] A.R.S. § 9-512(B).
[60] *Jung v. City of Phoenix,* 160 Ariz. 38, 770 P.2d 342 (1989).
[61] Defined at A.R.S. Const. Art. 15 § 2 to include, among others, *"[a]ll corporations other than municipal engaged in furnishing … electricity for light, fuel, or power[.]"*

energy credits from eligible resources.[62] These rules do not apply to municipal electric utilities. Neither do the ACC's resource planning and procurement rules,[63] which require load-serving entities[64] to submit annually for ACC review comprehensive data on load forecasts and generating resources in "Integrated Resource Plans."[65] The ACC does not maintain an independent "Resource Adequacy" program.

3.5 MUNICIPALIZATION STUDY PERIOD

The feasibility analysis includes assumptions about operation and implementation that will need to be better defined during a later phase. These assumptions are discussed in detail throughout the report, and they are needed in order to evaluate feasibility. The first assumption is with regard to the date at which the City would begin electric utility operations. This date would occur after the City has acquired the needed infrastructure from TEP, invested in separation and reintegration projects to fully separate the systems, procured power supply and the necessary overhead and systems for day-to-day utility operations. Based on the above successful attempts, once a vote for municipalization is achieved, it can take several years before the City is ready to begin serving customers. This timeframe will depend on multiple factors including but not limited to the transfer of TEP assets to the City, debt service funding, utility hiring and organizational requirements, power supply procurement, and any legislative or regulatory issue that may arise as a result of municipalization.

This study assumes a municipalization in-service date of January 2028. While this date is currently less than 3 years out, the date provides a basis for comparing the municipal operations to TEP operations. Moving the start date further into the future would be a reasonable approach in terms of technical feasibility, however, a start-date too far into the future requires longer-term forecasting for important input assumptions such as power supply costs and future TEP retail rates. Therefore, the 2028 start date should be viewed as illustrative for the purposes of understanding feasibility.

The feasibility assessment is viewed over a long-term planning period of 20 years or from 2028 through 2047. This length of time is selected to determine the impact of achieving GHG free power supply goals and because financing of the initial purchase price will need to be carried out via long-term debt of 20 to 30 years.

3.6 ELECTRIC DISTRIBUTION SYSTEM

The process of determining the estimated acquisition costs has two main steps: a) identify the assets to be acquired, i.e., the inventory; and b) determine the estimated cost of these assets. The electric facilities to be acquired consist of transmission poles and conductor, distribution substations, distribution poles and assemblies, overhead distribution conductor, underground conduit and conductor, transformers, meters, street lighting, and services. With respect to the distribution system, the City would need to acquire the assets from the electric meters on homes and business up to the substations. Most substations in the City Limits will be acquired so the City owns the high side of the 46kV substation as well as the low side (13kV or 25kV). For the 138kV substations, the City would take service at the high side of the power transformers and would also own the low side (13kV or 25kV). This point of demarcation creates a shared ownership for TEP's 138kV substation. In addition, the City would purchase the 46kV transmission lines within the City Limits. The City would acquire the distribution assets inside the City up to the City's municipal border. At the border, severance investments would be made to separate the City's customers from remaining TEP customers and assets.

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[62] A.A.C. R14-2-1801 *et seq.* The ACC initiated a proceeding on February 6, 2024 to eliminate its Renewable Energy Standard and Tariff (REST) rules.
[63] A.A.C. R14-2-700 *et seq*.
[64] In this context, a "load-serving entity" is a *"public service corporation that provides electricity generation service and operates or owns, in whole or in part, a generating facility or facilities with capacity of at least 50 megawatts combined."* A.A.C. R14-2-701.
[65] A.A.C. R14-2-703.

In order to mitigate any impact to remaining TEP customers, TEP's cost of service study was utilized to allocate the City's share of TEP rate base (plant). This methodology ensures that costs are equitably split between City and non-City customers regardless of the physical asset ownership. The cost of service method includes a share of local transmission assets that were deemed necessary based on GDS engineer review, and from the inclusion of these costs in TEP's retail rate model. Although these assets are assigned a "transmission" label, they are primarily used for distribution and are not included in TEP's formula transmission rate.

3.7 ELECTRIC GENERAL PLANT

If the City were to create a public power utility, TEP would have a large share of general plant that would no longer be needed to serve remaining customers. This study contemplates that the City would acquire its cost share of the general plant in addition to the distribution plant as described above. The acquisition of general plant avoids stranded asset issues and benefits all ratepayers. General plant that could be transferred includes items such as work yards, line trucks, equipment, tools, light duty vehicles, customer service centers, and other general use plant. The acquisition of general plant also reduces the cost to the City for start-up. The City would still need to acquire some general plant facilities such as customer information systems, metering infrastructure, office supplies, and other technologies.

3.8 FAIR MARKET VALUE

The study evaluates a range of fair market value of the TEP distribution and general plant assets. The range of value is typically determined based on two valuation approaches: Original Cost and Reproduction Cost. In the case of Original Cost, the original cost paid for the facilities is reduced by the depreciation that has accrued since these facilities were placed into service. This results in what is commonly referred to as the Original Cost Less Depreciation (OCLD) value or sometimes referred to as the "Net Book Value." This value usually sets the floor for utility valuations, assuming no contingent liabilities.

The Reproduction Cost Approach uses an estimate of the cost of reproducing the existing facilities as they are currently built as the basis for value. This system reproduction cost is then reduced to reflect the amount of depreciation, or age of the system. The valuation under such a method is generally referred to as the Reproduction Cost New Less Depreciation (RCNLD) value. This approach sets a ceiling for a system's fair market value. The likely asset purchase price generally falls between the two ranges. However, in Arizona, the issue of Going Concern is explicitly included in fair market value.[66] Going Concern is described more in this section including how it is added to the standard valuation methods.

3.8.1 Original Cost

The Original Cost Approach uses the original cost of the existing facilities as a measure of value. This valuation methodology is typically based on the utility's records of the original cost of plant and subsequent depreciation that has occurred over time. However, since the City would not acquire all TEP's distribution level assets, the TEP book value needs to be separated based on the infrastructure needed to serve electric accounts within the City. Ideally, a detailed review of TEP's system would produce the inventory, original cost, and age of all existing infrastructure needed to serve within the City. As this is a preliminary feasibility study, the valuation takes two approaches: 1) evaluate the cost share of plant to city vs. non-city customers using data provided by TEP and public documents, and 2) evaluation of specific substations and their estimated value using data provided by TEP and GDS engineering analysis. Combining these two approaches will result in a reasonable original cost value where the largest assets receive more detailed analysis.

[66] Arizona Revised Statutes: A.R.S. 9-518(b)

3.8.1.1 Cost Split between City of Tucson and Remaining TEP Customers

TEP provided a fully functional cost of service model which included the allocation of its rate base (plant) to each customer class. Using the methodology within the cost of service model, TEP's retail transmission, distribution and general plant assets are split between Tucson and all other customers. The resulting net book value for the City of Tucson customers is $829 million in distribution plant and $121 million in general plant (2021 values). Using the same cost of service methodology, these values are further adjusted for the book value reported in TEP's 2023 FERC Form 1. The resulting OCLD value totals $1,020 million for the plant that was recorded in 2023.

TABLE 3-3. ORIGINAL COST LESS DEPRECIATION VALUE, $MILLIONS

Description	FERC Account	TEP Total 2021 OCLD	Estimated City Share	City Only 2021 OCLD	City Only Adjusted 2023
Transmission Assets[a]	350-359	$70.4	49%	$34.2	$37.1
Distribution: Land & Land Rights	360	$8.5	51%	$4.4	$4.8
Structures & Improvements	361	$25.0	51%	$12.8	$13.9
Station Equipment	362	$274.0	51%	$140.9	$152.8
Poles, Towers, & Fixtures	364	$235.5	53%	$125.4	$135.9
Overhead (OH) Conductors & Devices	365	$167.7	52%	$87.9	$95.3
Underground (UG) Conduit	366	$63.3	56%	$35.2	$38.2
UG Conductors & Devices	367	$250.5	52%	$130.1	$141.1
OH Line Transformers	368	$94.4	52%	$49.1	$53.2
UG Line Transformers	368	$151.2	52%	$78.6	$85.2
OH Services	369	$21.7	56%	$12.1	$13.1
UG Services	369	$115.2	56%	$64.1	$69.5
Meters	370	$76.8	56%	$43.4	$47.0
Street and Traffic Lights	373	$13.7	79%	$10.9	$11.8
Total Transmission & Distribution		**$1,497.6**	**53%**	**$829.0**	**$899.1**
2023 Total Distribution [b]		**$1,700.6**			
2021/2023 Growth		114%			
2023 General Plant	390-398	$228.7	53%		**$121.3**
Grand Total (2023)					**$1,020.4**

(a) Estimated portion of transmission rate base allocated to retail customers.
(b) 2023 FERC Form 1

Since the system will not be acquired until 2028 at the earliest, TEP will continue to make investments and retirements and depreciation will continue. Using historical information, the distribution system within the City is adjusted for these factors through 2028. We estimate average annual plant additions at $48 million and annual depreciation expense at $44 million for both distribution and general plant. The resulting OCLD estimate for the combined distribution and general plant is $1,529 million in 2028.

3.8.1.2 Contributed Plant

During the public outreach process of this study, stakeholders raised the issue of customer-contributed plant. Contributed plant refers to assets paid by electric customers as part of their service extension or upgrade. The City should not have to pay for the assets that have been directly paid for by electric customers.

Customer contributions are excluded from the valuation methodology described above. For rate-setting purposes, the total rate base for TEP must subtract customer contributions, and the company's return on equity must not be applied to contributed plant.[67] Since our methodology sources TEP's cost of service rate base, customer contributions are removed from the distribution plant values.

3.8.2 Reproduction Cost Approach

The RCNLD value is based on the OCLD value except that original cost is adjusted to current construction values. The adjustment is based on the estimated original installment date for each asset category (FERC account). TEP's 2021 depreciation study is used to estimate system age based on remaining useful life. Specifically, the remaining useful life provides an estimate of the install date. The original cost values can then be adjusted using the Handy-Whitman index (HWI)[68] to determine reproduction cost. The HWI is a price inflator that tracks construction costs of public electric utilities.

TABLE 3-4. REPRODUCTION COST LESS DEPRECIATION VALUE

Description	FERC Account	TEP Total RCNLD	Estimated City Share	City Only 2021 RCNLD	City Only Adjusted 2023
Transmission Assets[a]	350-359	$222.0	49%	$107.9	$112.8
Distribution: Land & Land Rights	360	$41.3	51%	$21.1	$22.0
Structures & Improvements	361	$50.0	51%	$25.5	$26.6
Station Equipment	362	$480.0	51%	$244.8	$255.8
Poles, Towers, & Fixtures	364	$384.6	53%	$203.8	$213.0
OH Conductors & Devices	365	$527.3	52%	$274.2	$286.5
Underground (UG) Conduit	366	$142.0	56%	$79.5	$83.1
UG Conductors & Devices	367	$1,019.3	52%	$530.0	$553.8
OH Line Transformers	368	$645.7	52%	$335.8	$350.8
UG Line Transformers	368	$697.3	52%	$362.6	$378.9
OH Services	369	$46.2	56%	$25.9	$27.1
UG Services	369	$219.3	56%	$122.8	$128.3
Meters	370	$134.1	56%	$75.1	$78.5
Street and Traffic Lights	373	$43.4	79%	$34.3	$35.8
Total Transmission & Distribution		**$4,652.4**	**53%**	**$2,443.3**	**$2,552.9**
2023 Total Distribution [b]		**$4,861.1**			
2021/2023 Growth		104%			
2023 General Plant	390-398	$397.1	53%		**$210.7**
Grand Total (2023)					**$2,763.6**

(a) Estimated portion of transmission rate base allocated to retail customers.
(b) 2023 FERC Form 1

[67] Arizona Corporation Commission. Rate Base: Recording and Tracking Plant Assets. December 13, 2019. Available online: https://www.azcc.gov/docs/default-source/utilities-files/ombudsman/04-rate-base.pdf?sfvrsn=c8db9f9b_2
[68] Whitman, Requardt and Associates. Handy-Whitman Index of Public Utility Construction Costs. Bulletin No. 177. Baltimore, MD. 2013

The RCNLD value is adjusted for the investments and depreciation anticipated to occur prior to 2028, the acquisition date. Based on reproduction cost values, we estimate average annual plant additions at $70 million and annual depreciation expense at $46 million for both distribution and general plant. The resulting RCNLD estimate for the combined distribution and general plant is $3,390 million in 2028. All RCNLD values are adjusted to 2028 dollars.

3.8.3 Market Approach Benchmark

The Market Approach looks at a comparison of sales for comparable utilities. This approach is often difficult because sales of comparable utilities that are geographically close are infrequent. This approach generally looks at the percent premium over book value (also known as Original Cost Less Deprecation or OCLD) paid by the purchasing utility. Previous acquisitions of electric distribution plant have recognized premiums in the range of 19% to 36%. Based on a 36% premium, the market benchmark yields a value of $1.9 billion.

3.8.4 Going Concern

Going Concern is a value intended to compensate an IOU in cases of either condemnation or mutual agreement for the sale of utility plant. In Arizona, the related condemnation process ("Compensation for taking public utility; procedure for determining") explicitly includes the "value as a going concern" as part of the compensation that must be paid by a municipality when taking the plant and property of a public utility.[69] Relevant case law suggests that the fair market value must include the value of the certificate to do business (e.g., CPCN) as part of the going concern value.[70] The value is a factual question, reviewed under a reasonableness standard, and in one case the "allowance of nine percent of the physical properties as going concern value was not unreasonable."[71]

For this analysis, a Going Concern Value of 10% is added to the fair market value of the system to be purchased by the City.

3.8.5 Distribution System Asset Value

Table 3-5 below summarizes the estimated value of the system. The sensitivity analysis provides feasibility results using the value ranges below.

TABLE 3-5. ESTIMATED 2028 DISTRIBUTION SYSTEM FAIR MARKET VALUE, (MILLIONS)

Valuation Methodology	2028 System Value	Going Concern	Total
OCLD	$1,274	$127	$1,401
Average	$2,332	$233	$2,565
RCNLD ($2028)	$3,390	$339	$3,729
Market Approach Benchmark			$1,906

3.9 REVIEW OF PHYSICAL SEPARATION

3.9.1 Valuation of Physical Transmission and Substation Assets Needed for Service

The feasibility assessment relies on the system valuation as described above in Section 3.8. This section of the report evaluates whether the substation value is sufficient for utility separation and operation. Specifically, GDS engineers evaluated the system's high voltage assets to determine the specific plant that would be physically

[69] A.R.S. 9-518(b).

[70] See City of Tucson v. El Rio Water Co. (1966) 101 Ariz. 49, 415 P.2d 872.

[71] *City of Phoenix v. Consolidated Water Co.* (1966) 101 Ariz. 43, 415 P.2d 866.

acquired. It was determined that the values included in Table 3-5 sufficiently cover the assets that would be acquired based on the current separation plan.

3.9.1.1 Physical Description

For the transmission and substation facilities, all 46kV substations and 46kV transmission lines within the city limits would be acquired. The study assumes the separation of the 46kV transmission lines will be the point where the line crosses the City boundary. Because the City can only acquire facilities within the city limits, the separation is made at the edge of the City Limits. However, in the future, a point of demarcation could be determined such that ownership changes at the termination point of the transmission line such as at a substation or disconnect switch. GDS utilized Google Maps to establish the location of the 46kV substations and 46kV transmission lines within the City Limits. These assets are shown in the figure below.

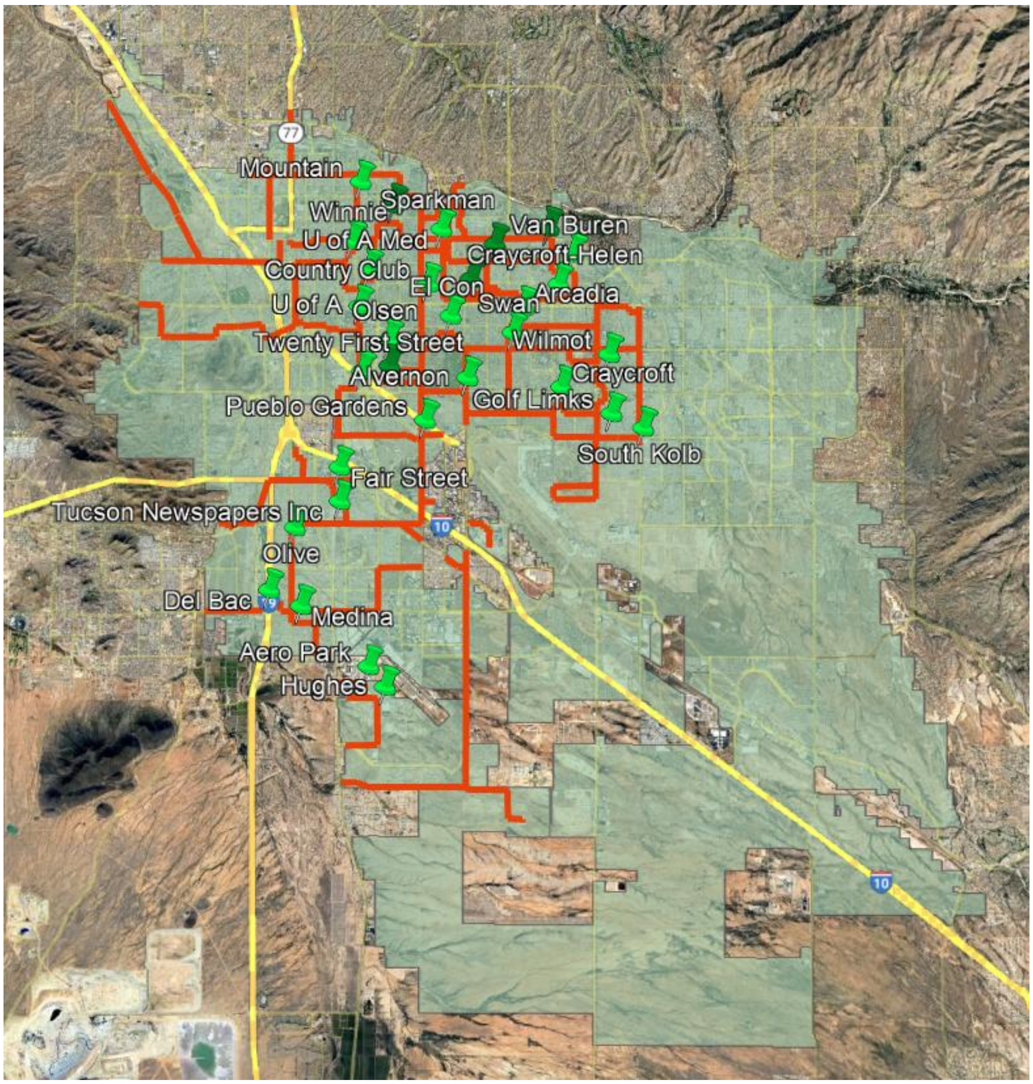

FIGURE 3-2. 46KV TRANSMISSION LINES AND 46KV SUBSTATIONS WITH THE CITY LIMITS

For 115kV transmission lines, it is assumed that TEP will continue to own and operate these facilities. For 115kV distribution substations located in the City Limits which serve customers within the City Limits, the assumption is the City will take transmission service at these substations. It is further assumed that TEP will continue to own and operate the 115kV breakers, 115 kV high side bus works, and that the point of delivery to the City will be the high side of the power transformer in the substation. The City will acquire and operate the power transformers, voltage regulation, and low side distribution protective devices such as breakers and relays. The following map depicts the 115 kV substations to be acquired.

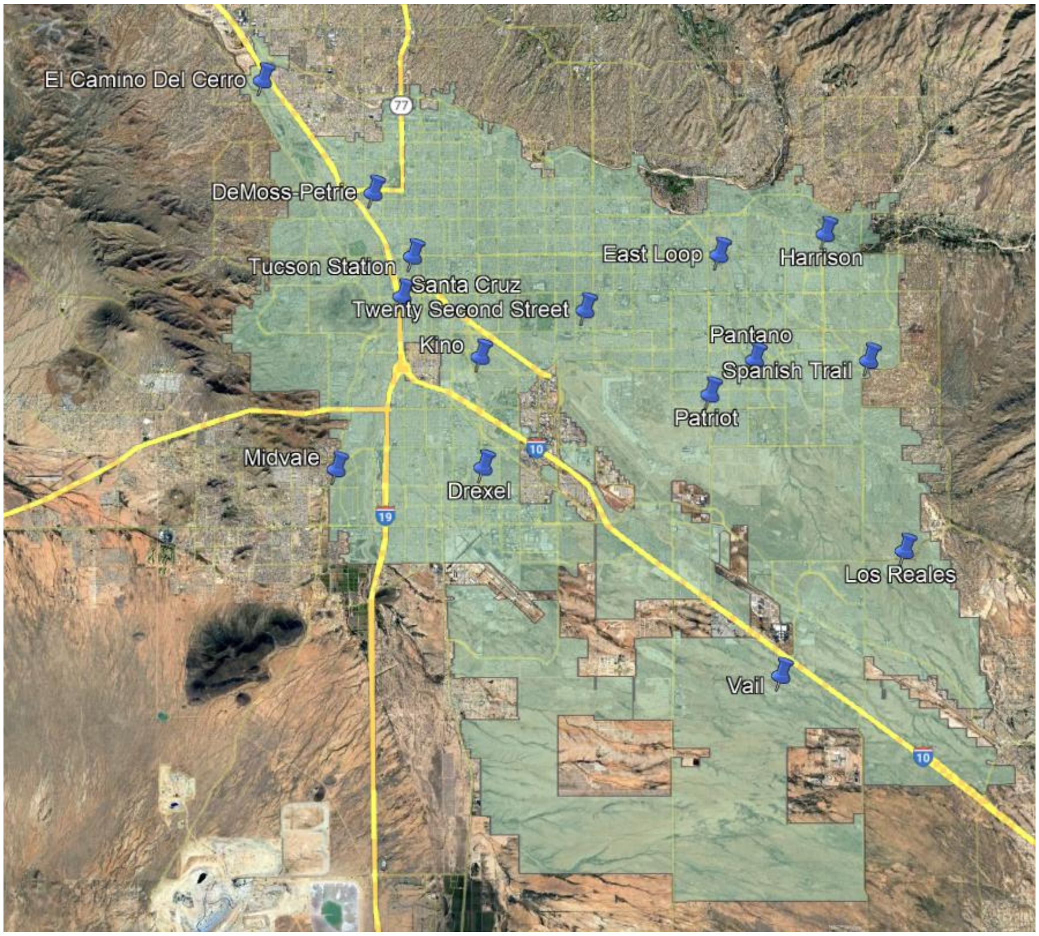

FIGURE 3-3. 115KV SUBSTATIONS WITH THE CITY LIMITS

The following is a list of the 46kV substations and 115kV substations to be acquired:

46kV Substations to be Acquired	
Substation	Voltage
Aero Park	46kV
Alvernon	46kV
Arcadia	46kV
Country Club	46kV
Craycroft	46kV
Craycroft-Helen	46kV
El Con	46kV
Fair Street	46kV
Golf Links	46kV
Grant	46kV
Hedrick	46kV
Hughes	46kV
Medina	46kV
Mountain	46kV
North Alvernon	46kV
Olive	46kV
Olsen	46kV
Pueblo Gardens	46kV
Sears	46kV
Shannon	46kV
South Kolb	46kV
Sparkman	46kV
Swan	46kV
Tucson Med Center	46kV
Tucson Newspapers Inc	46kV
Twenty First St	46kV
U of A Med	46kV
U of A	46kV
Van Buren	46kV
Warehouse	46kV
Wilmot	46kV
Winnie	46kV

115kV Substations to be Acquired	
Substation	Voltage
DeMoss Petrie	115kV
Drexel	115kV
El Camino Del Cerro	115kV
Harrison	115kV
Kino	115kV
Los Reales	115kV
Midvale	115kV
Pantano	115kV
Patriot	115kV
Rillito	115kV
Santa Cruz	115kV
Spanish Trail	115kV
Tucson Station	115kV
Twenty Second Street	115kV
Vail	115kV

In addition, we estimate that 136.87 miles of 46kV transmission lines would be acquired. Using Google Earth, GDS made an estimate of the major components in the substations to develop a reproduction cost new of the assets. Then GDS used their proprietary unit cost data set to value the assets based on current construction costs.

The age of these assets is unknown. GDS assumed the transmission substations are 50% depreciated. Other systems GDS has inspected have a system depreciation of 70% and other systems are relatively new with a deprecation of 25%. Thus, the selection of 50% is a conservative value for this initial valuation. This same assumption was used for the transmission lines to be acquired.

The following table is a summary of the RCN, RCNLD, Original costs and Book value for the transmission and substations assets to be acquired. These values are not used directly in the feasibility assessment. Rather they are included to show that the substations required for service within the City are in total value less than the City's COSA-allocated costs as discussed in Section 3.7. This means that using the COSA-allocated costs is a reasonable approximation of the physical asset value, and it is conservative in that the study is assuming more cost than is needed to operate the system. Additionally, the City is not leaving stranded assets and would not need to compensate remaining TEP customers.

TABLE 3-6. TUCSON ENERGY SOURCING STUDY VALUATION, MILLIONS

Item	FERC Account	Total Original Cost	Book Value: Original Cost Less Depreciation	Reproduction Cost New	Reproduction Cost – New Less Depreciation
Total Transmission Plan	350	$91.9	$41.9	$260.1	$118.5
Substations	362	$100.0	$45.3	$323.4	$147.3
Total Transmission & Substation Plan		**$191.9**	**$87.2**	**$583.5**	**$265.8**

The following conditions were assumed for the valuation of the substation and transmission assets.

- The analyses discussed herein were prepared using information that is generally available to the public, and available to the firm from prior engagements.
- It was assumed that there is no environmental contamination associated with the assets being valued and that such property is actively operated and will continue to be operated in accordance with all existing environmental laws and regulations.
- All existing liens and encumbrances have been disregarded, and the value of the property was assessed as though free and clear and under responsible ownership.
- It has been assumed that the City would operate the Electric Facilities in a reasonable and prudent manner reflective of accepted industry standards.
- It was assumed that the assessed assets conform to all applicable zoning laws and use regulations and restrictions, as well as all applicable federal, state, and local environmental regulations and laws.

3.9.2 Separation and Reintegration of Distribution Facilities

The circuits off of substations often serve loads inside and outside the City Limits. The general plan is for the City to acquire the distribution facilities within the City Limits to provide service to those electric customers within the City Limits. However, to separate the existing system will require reintegration of the services which exist outside of the City Limits.

3.9.3 Principles of Separation and Reintegration

3.9.3.1 Similar Quality of Service

Extracting portions of an operating distribution system for transfer of assets to a third-party such as a municipality should not impair the integrity of the remaining system. The criteria for making a system whole are similar to the planning criteria used by the utility. A distribution system has two key operational criteria: delivery voltage and capacity of the line. Thus, after separation, and as a system is reintegrated the delivery voltage and capacity of new or reintegrated lines must have sufficient capacity to serve the load. Further, the conductors used should be consistent with the utility's current standard wire sizes. It is important that a balance be maintained in that the reintegration should not make a "better" system but a system that is equivalent or similar in nature to the original.

Key consideration is to provide existing TEP cutomers with service of similar character as these customers received prior to the separation of the assets. Normally this means that customers that had access to back feed capabilities should have similar service in the future to the extent practicable. To accomplish this requirement, rather than building a new substation, GDS assumed that the two parties could agree on the use of bi-directional primary meters which normally would be open at the City Limits and allow power flow between the City and TEP. These primary meters could be closed to allow for emergency backup as needed in a contingency circumstance to assure safety and upstream system integrity.

Tucson Electric Power provided distribution system maps which GDS utilized to estimate the cost of reintegration and to determine the location of primary meters. GDS estimates 25 primary meters will be necessary.

In many instances the City Limits paralleled or otherwise followed natural barriers preventing distribution lines from crossing the City Limits. These include dry riverbeds or washes, railroad rights-of-way, and interstate rights-of-way.

For areas that require reintegration, the type of service is determined based on the current configurations. Specifically, if an area is primarily served via underground electric power, then underground lines are proposed. If the area had primarily overhead electric service, then overhead lines are proposed. A total of 19.7 miles of new 3-phase overhead distribution lines are required and 20.2 miles of 3-phase underground cables are required.

Based on the GDS assessment, the separation and reintegration will require the City to take service from two existing TEP substations: Robert Billis Substation and the Sonoran Substation. TEP would retain ownership of these substations and the City would own a transformer on the low side.

The total estimate cost for the reintegration is summarized below. These costs are incorporated into the feasibility assessment.

TABLE 3-7. TUCSON ENERGY SOURCING STUDY SEPARATION REINTEGRATION

Item	FERC Account	Construction Costs
Substations	362	$8,531,590
Distribution Poles & Assemblies	364	$4,600,831
Overhead Distribution Conductor	365	$5,011,090
Underground Conduit	366	$18,172,615
Underground Conductor & Devices	367	$18,468,630
Primary Meters	370	$255,495
Total Distribution Plant		**$55,040,250**

3.10 PUBLIC POWER UTILITY BUDGET

3.10.1 Power Supply

Power supply costs are calculated for the public power utility based on forecast costs for renewable energy, market purchases of non-renewable energy, capacity, and transmission and ancillary services. These costs are feasibility-level estimates based on the current market outlook and planning environment. It is assumed that the utility would procure a mix of short-term and long-term power supply contracts and, at least initially, fully hedge power purchases. The power costs are built up from the hourly load forecast for the entire City electric load requirements and take into account the generation profiles for specific generating resources.

Ultimately, the characteristics of the electric portfolio would be guided by the City Council or other governing board. For the purposes of the feasibility study, the baseline power portfolio analyzed for the City of Tucson municipal utility include the following:

- ***Base Case:*** Achieves 50% renewable energy supply in 2028 and 100% by 2045.
- ***Accelerated Renewables:*** Achieves 50% renewable energy supply in 2028 and 100% by 2035.

The power supply costs are based on variables and market expectations that change daily. The base case best represents a likely least-cost scenario provided tax credits and power supply markets continue at the current trends. To analyze the uncertainty of power costs, a high power cost scenario is developed. Each component of the power supply is described below and the assumptions for base case and high cost scenarios are provided.

3.10.1.1 Energy

The non-renewable portion of each portfolio is priced based on forecast wholesale market prices at Palo Verde adjusted for the Tucson area. The (Southwest) Palo Verde is the wholesale electric market closest to the Tucson area (see Figure 3-4).

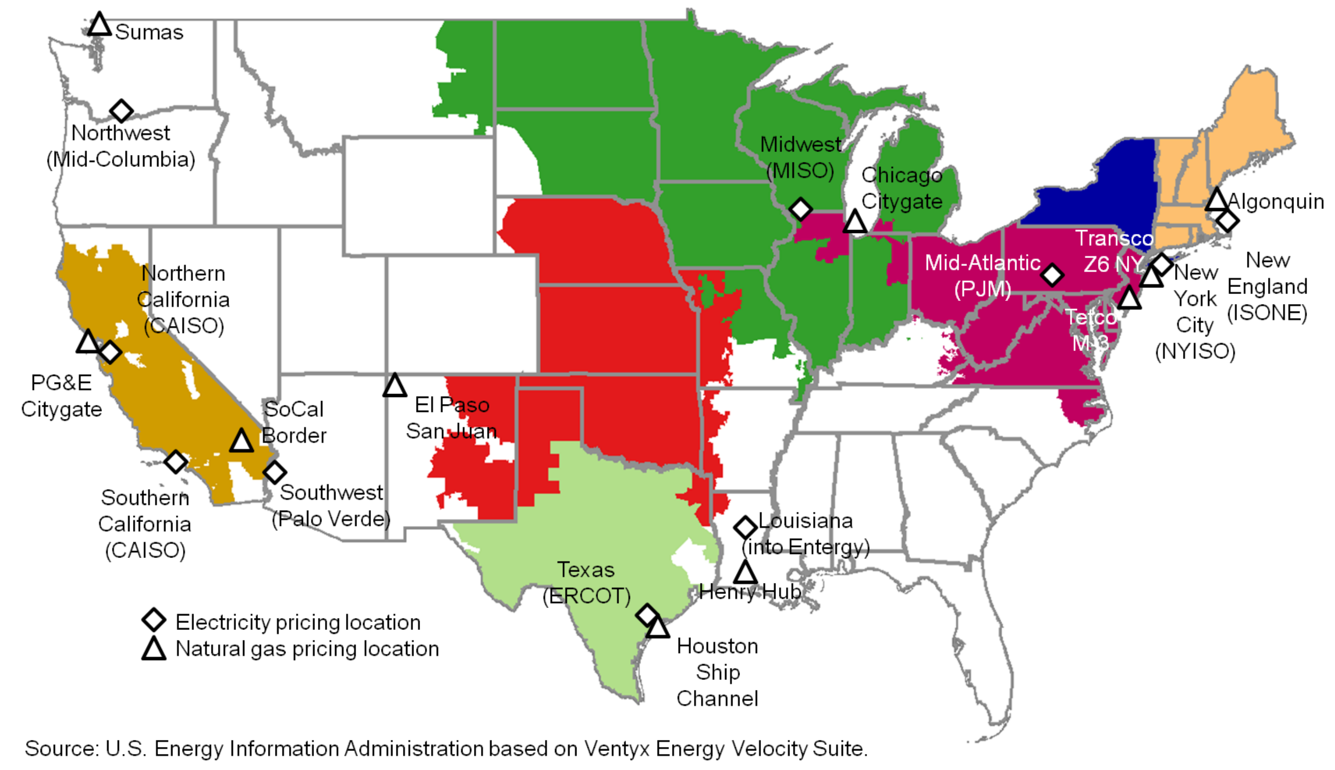

FIGURE 3-4. WHOLESALE ELECTRICITY AND NATURAL GAS PRICING LOCATIONS

The forecast is based on pricing forwards obtained in February 2025. [72] The forwards are provided for peak and off-peak periods where the peak period is for the hour ending 7 through hour ending 22. Off peak periods are all other hours. Market prices are applied to the hourly load forecast so that the timing of energy use can be valued based on its peak and off-peak shape.

[72] S&P Global. Palo Verde forward curve. Data Accessed February 6, 2025.

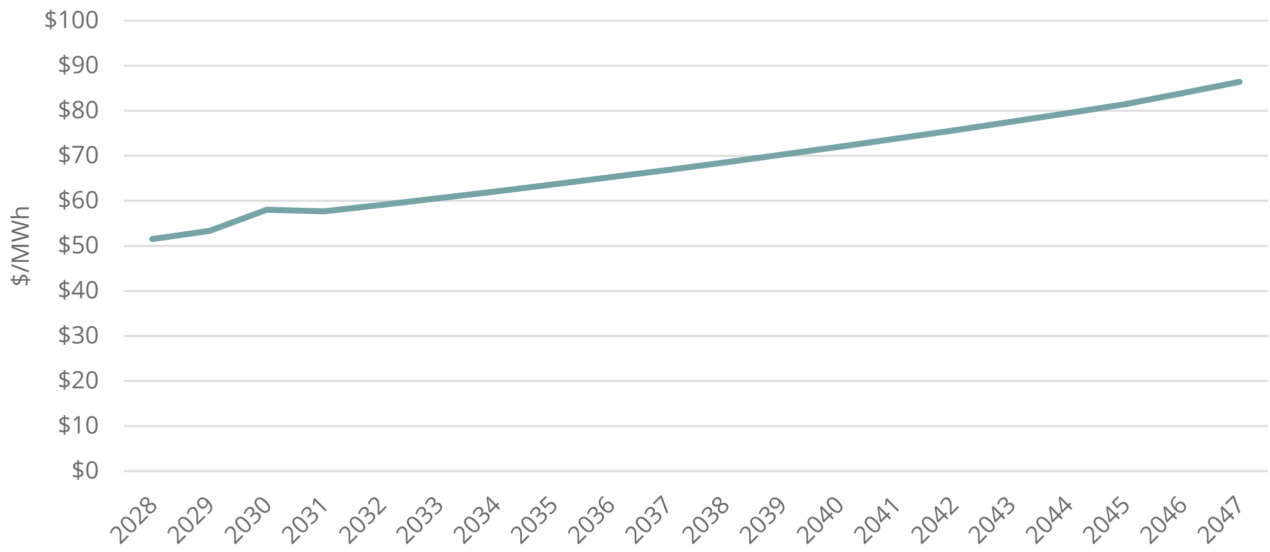

FIGURE 3-5. BASE CASE FORECAST WHOLESALE PRICE OF ELECTRICITY AT PALO VERDE

To model a high price scenario, five years of historical prices were analyzed to determine the variability for pricing during peak and off-peak periods and by month.[73] The high price is developed by calculating the 85th percentile to the forecast period prices. Figure 3-6 compares the high and base case price forecasts.

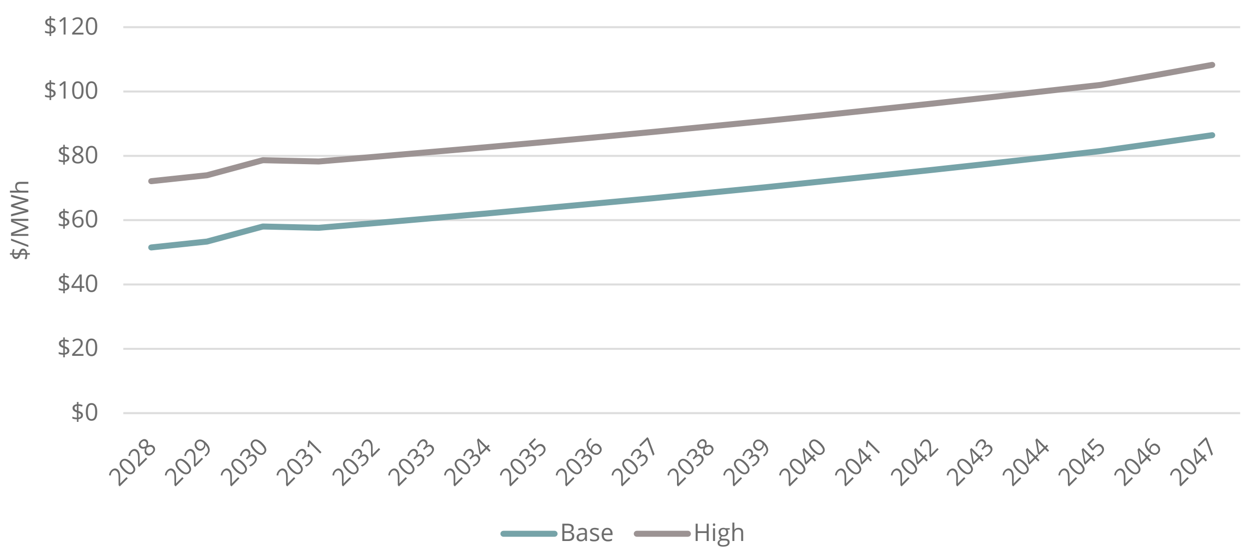

FIGURE 3-6. ENERGY PRICE FORECAST SCENARIOS

3.10.1.2 Capacity

Resource Adequacy is a regulatory construct that ensures there is enough capacity and reserves for the grid operator to maintain a balanced supply and demand across the electric system. Since Arizona is vertically integrated, individual utilities act as their own balancing authorities and manage the electrical grids within their territory. Thus, Arizona does not have its own Independent System Operator (ISO) or Regional Transmission Organization (RTO). As a result, there is not the same kind of RA market as in other states that have a competitive

[73] S&P Global. Palo Verde wholesale electricity historical prices April 1, 2019 through March 31, 2025. Data Accessed March 31, 2025.

energy retail market with active RA trading. RA is handled on a utility-by-utility basis through approval of their IRPs where the most reliable and cost-effective resources are identified to meet the energy needs over a 15-year period, updated every 3 years. Some Arizona utilities participate in the Western Resource Adequacy Program (WRAP) operated by the Southwest Power Pool, which allows participating utilities to swap RA capacity in real-time. In addition to spreading the reserve margin across WRAP participants, the program direct participants with excess capacity to hold back capacity during critical periods to support participants without enough power supplies to serve their load. WRAP has binding obligations enforced by penalties, but the penalties do not take effect until 2028. WRAP includes 26 utilities in AZ, WA, OR, ID, MT, WY, NV, UT, CO, and very small pockets of Northern CA. The feasibility study assumes a public power utility would participate in the WRAP.

The power supply cost forecast assumes that a new public power utility would need to meet RA requirements. In order to evaluate the potential cost of RA, the study assumes capacity planning margins consistent with the WRAP.[74] The requirement determines the amount of capacity each utility must procure, and it determines the resource capability for each type of resource depending on region. For example, a typical requirement would be for a utility to procure capacity equal to 110-120% of its maximum expected peak demand in each month. If that utility owns a 200 MW solar resource, the utility can use that resource to meet a portion of the requirement based on the resources' contribution at the time of the utility system peak. In Arizona, the capacity for a solar resource during the month of July is 24.2% of the total capacity, or 48.4 MW out of 200 MW.

The price for capacity in 2028 is based on an escalation of current pricing trends. Recently, investor-owned utilities in CAISO and Arizona have reported capacity costs for purchases and production averaging around $5/kW-month and $10/kW-month.[75] The lower value is associated with the production cost from existing infrastructure whereas, the $10/kW-month is representative of the average market value for bilateral transactions. For the purposes of feasibility, it is assumed that capacity is priced at the higher value of $10/kW-month. This value is escalated over the timeframe based on expected inflation. The high price scenario assumes a higher inflation estimate of 5% through 2032 and then 2.5% after. The high cost scenario reflects the marginal cost of capacity through investments in new plant such as battery storage.

3.10.1.3 Renewable Supply

The primary component of the City public power utility's renewable energy supply is utility-scale solar. Utility-scale solar in the non-ISO western U.S. has grown by approximately 1,400 MW per year across an average of 20 projects per year. Arizona currently has an annual solar capacity of over 3,200 MW. If used locally, this capacity is estimated to provide an estimated 8.6% of the total state electric load. In 2023 alone, 6 new solar projects were developed in the State. Not only is solar widely available, but the price of solar power purchase agreements (PPA) have continued to decline. Figure 3-7 illustrates national solar and wind PPA price trends from the Lawrence Berkeley National Laboratory (LBNL). These declines are consistent with the 8% decrease in installed costs since 2022.[76]

[74] Western Resource Adequacy Program (WRAP) New Participant Info Session. October 14, 2022.

[75] Based on proprietary information.

[76] Lawrence Berkely National Laboratory. Utility-Scale Solar, 2024 Edition. Berkely Lab October 2024. Available at: Utility-Scale Solar

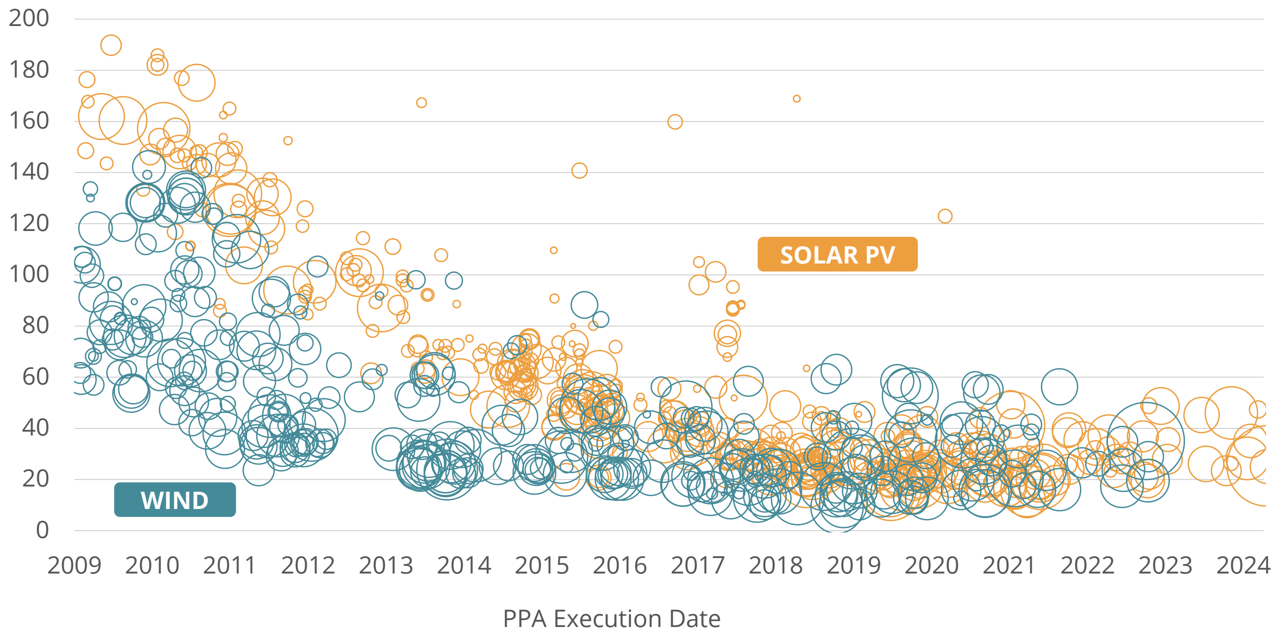

FIGURE 3-7. RENEWABLE PPA PRICE TRENDS ($2023/MWH)[77]

Figure 3-8 compares solar PPA prices across the various regions. Arizona is located in the West (non-ISO) region. Solar PV PPA prices for this region averaged $27/MWh in 2024.

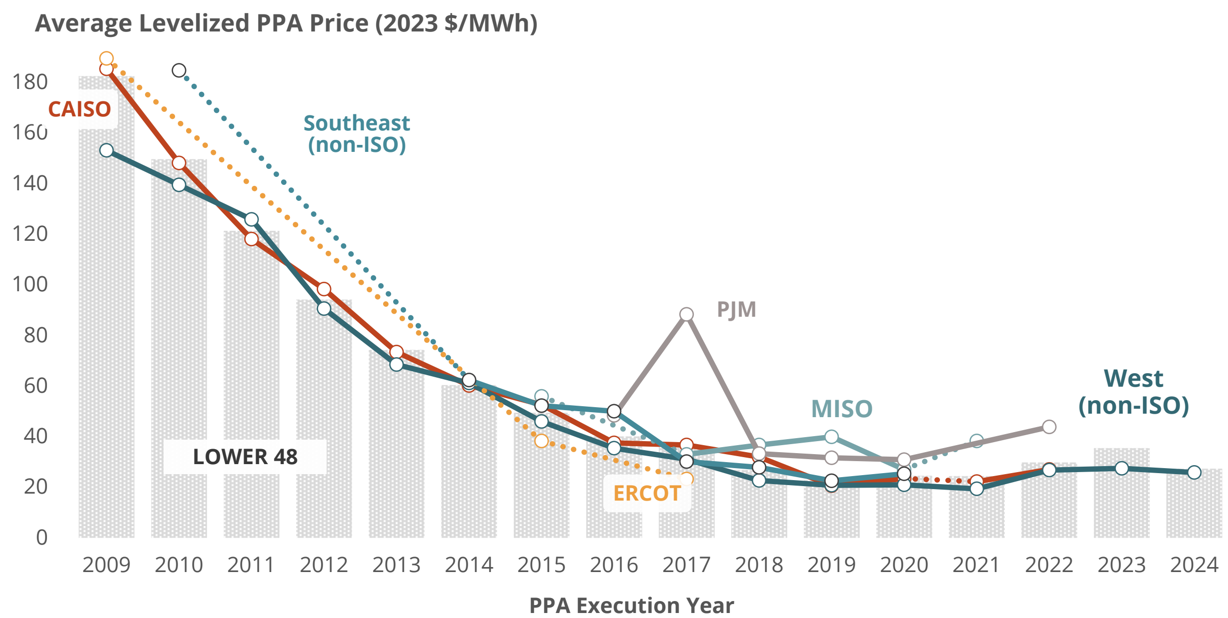

FIGURE 3-8. SOLAR PPA PRICES BY REGION

[77] Prices are levelized. Source: Lawrence Berkely National Laboratory. Utility-Scale Solar 2024 Edition Database. Available at: https://emp.lbl.gov/utility-scale-solar/

Solar resources are often paired with battery storage. The pairing helps with grid reliability and in reducing overall power supply costs since the batteries can be discharged during high priced periods for electricity. The price for solar combined with significant battery storage (50% or more) in 2024 averaged $45/MWh in Arizona. The LBNL reports that solar PPA pricing in the $38-$45/MWh range for the most recent pricing period in the California Independent System Operator (CAISO) region.[78] Prices and installed costs are expected to decline into the future. Because the CAISO region is often higher-priced than Arizona, the study assumes a solar PPA price of $35/MWh starting in 2028. This price is conservatively higher than the $27/MWh price for regional solar and allows for some battery storage optionality and transmission integration in the cost.

The high power cost scenario assumes solar prices at $45/MWh. This value represents the loss of tax credits as well as higher construction costs and potential transmission integration costs.

3.10.1.4 Renewable Energy Standard

The Arizona Corporate Commission has jurisdiction over renewable energy via the Renewable Energy Standard and Tariff (REST) program, originally approved in 2006. REST required that regulated electric utilities generate 15 percent of their energy from renewable resources by 2025. At the February 6, 2024 meeting, the Commission voted 4-1 to initiate a proceeding that repeals the REST rules and eliminates gas and energy efficiency and demand side management rules citing market distortion and higher energy costs for customers. The Commission does not regulate municipal utilities (except regarding gas pipeline safety), and there are currently no statewide renewable energy requirements for municipal utilities in Arizona.

3.10.1.5 Transmission/Ancillary

The City public power utility would need to obtain transmission services to transport the procured power supply from its delivery point to the distribution system. TEP projects its 2025 formula rate at $1.99/kW-month.[79] This rate is forecast based on TEP's transmission revenue requirement and total kW in reservations and firm network service. The transmission revenue requirement is forecast to increase at 5% annually based on the previous 3-year average increase. The kW forecast is based on a 4% escalation which is the average growth rate from 2021 through 2025. The resulting transmission rate is expected to increase by approximately 1.3% annually through 2045.

3.10.1.6 Power Supply Cost Summary

The figures below summarize the power supply cost forecast for the first 10 years of the study. The high case is 19% higher than the expected, or base case.

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[78] Nominal prices. Source: see id.

[79] 2025 TEP OATT Projection. September 25, 2024. Available at OATI OASIS.

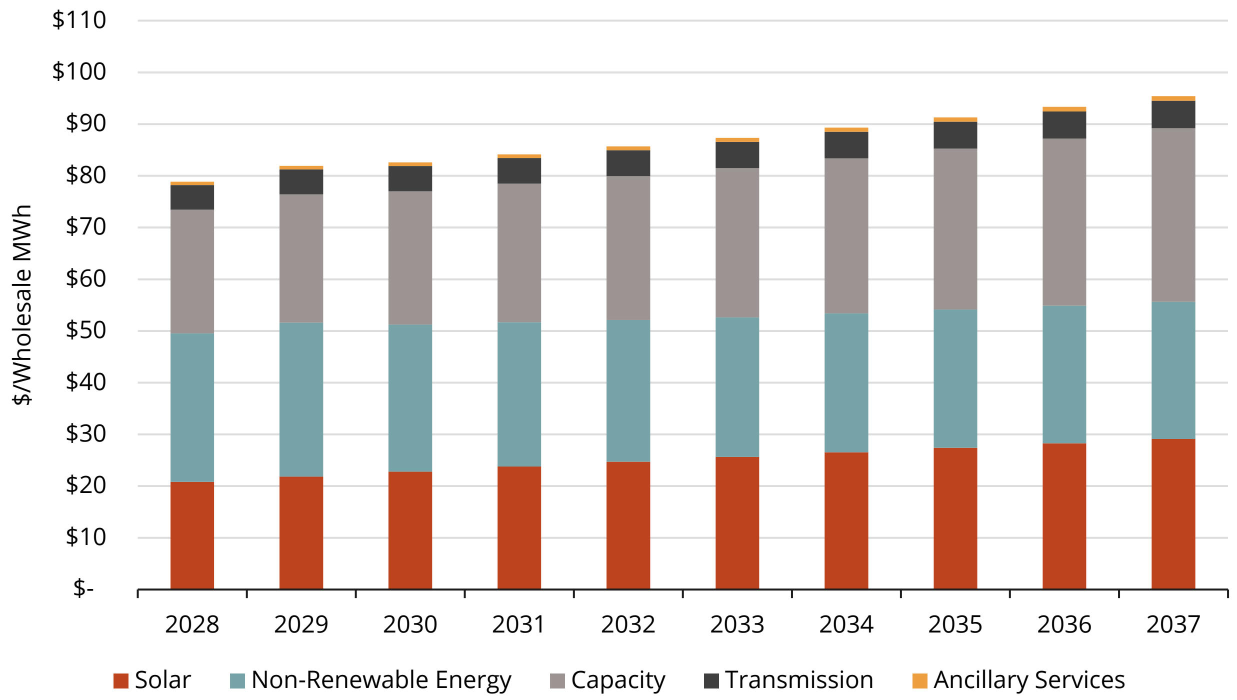

FIGURE 3-9. BASE CASE POWER COST FORECAST

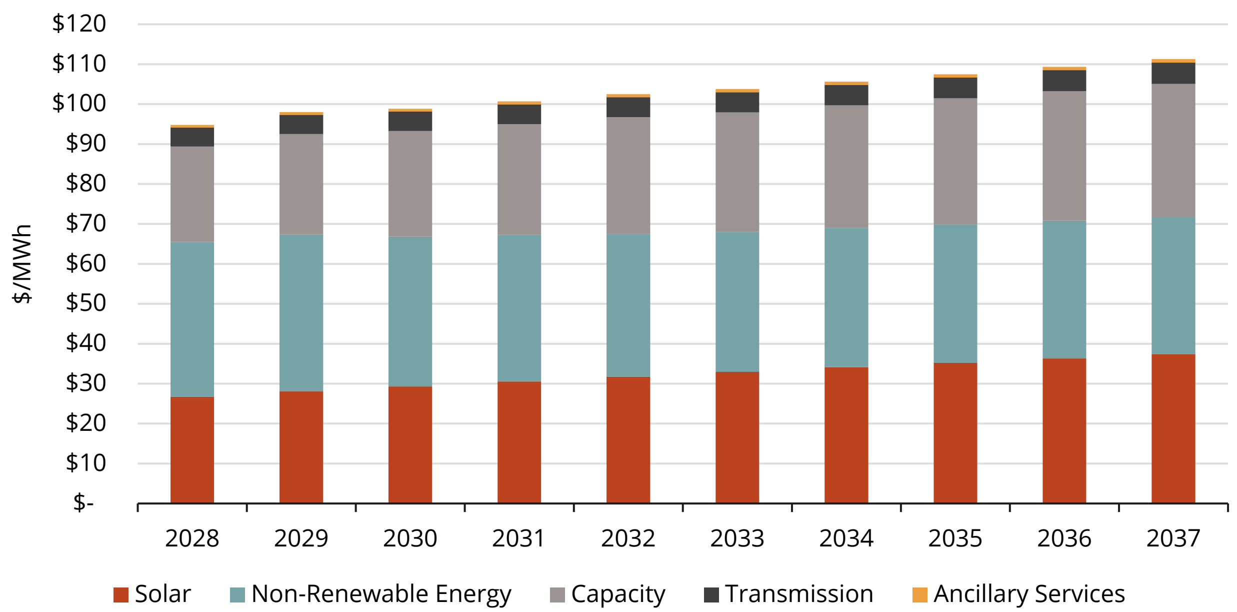

FIGURE 3-10. HIGH CASE POWER COST FORECAST

3.10.2 Other Operating Costs

Three other operating cost categories are included in the public power Utility budget. These include the following:

(a) ***Distribution Operation and Maintenance:*** Annual expenses related to operating and maintaining the current distribution system. Example costs include reliability replacements, streetlight maintenance, underground maintenance, overhead maintenance such as tree trimming and pole replacements among other regularly performed operations.

(b) ***Customer Service and Billing:*** Costs associated with customer service and billing including staff costs for customer service call center, meter reading and bill preparation, information systems, uncollectable or bad debt, marketing, energy efficiency programs, low-income programs, and key account activities.

(c) ***Administrative and General (A&G):*** Expenses for A&G include items such as property taxes, insurance, staff salaries and benefits, maintenance related to general plant such as line trucks and work yards.

Typically, the above costs scale with the size of utility (number of customers or electric load size). GDS reviewed both our internal database of municipal system operating costs as well as publicly available data for regional municipal utilities to develop estimated operating costs.[80] Total costs ranged from $341/service account to $878/service account. Average costs are $600 per account. For reference, TEP costs for these same services were $570 per service account in 2023.[81]

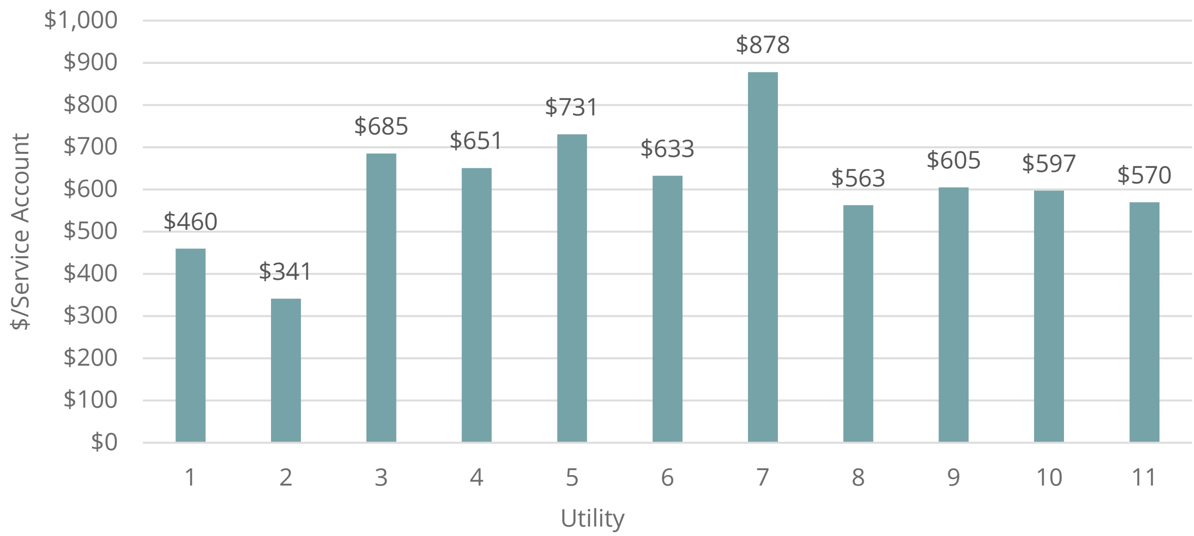

FIGURE 3-11. OPERATIONS & MAINTENANCE COST SURVEY

3.10.2.1 Labor Costs

Labor costs are a large share of electric utility non-power operating costs. The public outreach portion of this study identified a concern regarding the continued support for relevant labor unions[82] under a municipalization scenario. While this study does not contemplate specific operating scenarios (hire of union or non-union workers), we found that the issue regarding labor costs would be relevant to the feasibility assessment. Based on the

[80] Publicly available data included City budgets posted on websites and audited financial statements for the Town of Thatcher, AZ; Mesa, AZ; Colorado Springs, CO; and Farmington, NM.

[81] TEP 2023 FERC Form 1.

[82] Relevant labor unions include but are not limited to the International Brotherhood of Electrical Workers (IBEW) and Utility Workers Union of America (UWUA).

comparison of municipal overhead costs with TEP expenses, it was determined that the estimated operations and maintenance (O&M) costs for the municipal utility were sufficiently high enough to account for the cost of labor regardless of union membership.

3.10.2.2 Capital Improvements

The City public power utility would need to routinely undertake capital projects to ensure the continued safe and reliable operation of the distribution system. The City's governing entity could choose to either fund the needed capital improvement projects directly from retail rate revenues or fund the program through borrowing. Public utilities often utilize both strategies to balance year-to-year rate impacts. It is assumed that capital project costs would remain at a consistent level over the forecast period. The public power budget assumes half of Capital Improvement Projects (CIP) would be debt financed and the other half would be rate-funded. The estimated Capital Improvement Projects expense for the public power utility is provided in Table 3-8 and is based on 3.8% of the estimated reproduction cost. This assumption is conservatively high because it assumes a physical useful life of equipment at 26 years. TEP's depreciation study states that the weighted average useful life of equipment is 50 years.

TABLE 3-8. CAPITAL IMPROVEMENT BUDGET ESTIMATE, $MILLIONS

	Distribution	General Plant	Total
Total Capital Expenditure (3.8% Depreciation)	$101.5	$23.0	$124.5
Rate-Funded			$62.2
Debt Funded			$62.2

3.10.2.3 Payments in Lieu of Taxes

TEP collects funds for taxes levied by various regulatory and government authorities. These taxes apply to City of Tucson customers, and various entities could lose revenue if the public power utility did not make payments on par with the current TEP payments. The study conservatively assumes that the Municipal Utility would continue to collect and make payments for all current taxes currently paid by TEP electric customers. This includes the Public Utility Tax, Franchise Fee, City Sales tax, State Sales tax, and regulatory charges. The total estimated payment in lieu of taxes (PILOT) is estimated at 13%. These expenses are included in the public power utility operating costs.

3.10.3 Non-Operating Expenses

Non-Operating Expenses include debt service and miscellaneous revenues. These are discussed below.

3.10.3.1 Debt Service

Debt service costs are estimated based on typical costs for taxable and tax-exempt debt. [83] The study assumes taxable financing for the purchase of the utility assets from TEP and tax-exempt financing for all other requirements. Currently, the tax-exempt bond rates for municipal utilizers are about 4.1%[84] and taxable financing is estimated at 4.7%.[85] The bond issuance is assumed to include the following costs:

- Debt Service Reserve (1 month debt service)
- Capitalized Interest (2 months debt service)
- Accrued Interest (1/2 month debt service)

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[83] National Association of Bond Lawyers. *Protecting Bonds to Build Infrastructure and Create Jobs.* January 2025 Available at: https://www.nabl.org/wp-content/uploads/2025/01/2025-Bonds-Data-Brief.pdf

[84] 30-year tax exempt rate for AAA municipal bonds as of March 2025. https://www.fmsbonds.com/market-yields/

[85] Equal to the 30-year treasury bond yield https://econforecasting.com/forecast/t30y plus the difference in 30-year treasury rate (https://www.treasurydirect.gov/marketable-securities/treasury-bonds/) and AAA rated Moody's borrowing rate. https://fred.stlouisfed.org/series/AAA

- Bond Insurance ($0.91%)[86]

Table 3-9 shows the components of the bond issue.

TABLE 3-9. INITIAL BOND REQUIREMENTS

	Borrowing Term Years	Borrowing Rate	Value ($2028, Millions)
Distribution System Acquisition Cost	30 Interest Only Payments Made for First 2 Years	Taxable	**RCNLD: $3,729** **OCLD: $1,401**
Separation and Reintegration Costs	30	Tax-Exempt	**$55**
Start-Up and Transaction Costs	10	Tax-Exempt	**$134**
O&M Reserve (90 Days)			$88
CIP Reserve (2 Months)			$21
Start-Up Costs			$15
Transaction Costs			$10

The O&M Reserve is equal to 90 days (3 months) operating costs for the public power utility. The typical lag between collecting revenue from customers and paying operating costs is 60-90 days. The O&M reserve provides the cash needed for working capital. Similarly, the CIP reserve is funded for 2 months so that service can continue prior to revenue collection.

Start-up costs are the costs of beginning utility service and may include the cost of purchasing equipment, supplies, software, management systems, and hiring employees. Start-up costs here are adjusted for the assets that would be acquired from TEP through the purchase of TEP's general plant that would no longer be needed.

Transaction costs include legal and professional fees incurred during the negotiation of the system purchase from TEP. Legal and other transaction costs can be significant for Cities that follow through with a condemnation process. For example, in Boulder, Colorado, the city spent over $28 million over the course of 10 years working toward establishing a municipal utility.[87] In Winter Park, Florida, the city paid much less than this amount despite the contentious process.[88] From a sensitivity perspective, the City could pay multiples of the budgeted $10 million and still easily achieve economic feasibility.

[86] Based on large bond amounts above $10 million.
Joffe, Marc. *Doubly Bound The Costs of Issuing Municipal Bonds*. UC Berkely. December 2015.
https://belonging.berkeley.edu/sites/default/files/haasinstituterefundamerica_doublybound_cost_of_issuingbonds_publish.pdf

[87] Best, Allen. *As costs rack up in Boulder's push to split with Xcel, voters to have the final say.* October 29, 2020. Available online: https://coloradonewsline.com/2020/10/29/as-costs-rack-up-in-boulders-push-to-split-with-xcel-voters-to-have-the-final-say/

[88] Winter Park issued $49 million in bonds to cover all transaction and acquisition costs. Kury, Ted. *Maine voters don't like their electric utilities, but they balked at paying billions to buy them out.* Available online: https://news.warrington.ufl.edu/faculty-and-research/maine-voters-dont-like-their-electric-utilities-but-they-balked-at-paying-billions-to-buy-them-out/

3.12 ANNUAL BUDGET

The resulting budget is shown for years 1, 5, 10, and 20 in the table below.

TABLE 3-10. PUBLIC POWER UTILITY REVENUE REQUIREMENT, MILLIONS

	2028	2032	2039	2047
Power Supply & Transmission	$415	$469	$585	$770
Distribution O&M	$51	$62	$85	$112
Customer Service & Uncollectible	$18	$22	$30	$43
A&G	$84	$102	$140	$184
Capital Improvement	$62	$72	$93	$122
Debt Service: Capital Projects	$5	$25	$68	$123
Debt Service: Acquisition (RCNLD)	$177	$235	$235	$235
Debt Service: Start-Up Costs	$17	$17	$0	$0
Debt Service: Separation & Reintegration	$3	$3	$3	$3
PILOT	$135	$153	$187	$247
Stranded Generation	$51	$1	$1	$49
Revenue Requirement	**$1,018**	**$1,160**	**$1,428**	**$1,890**

3.13 TEP RATE FORECAST

TEP charges customers for service through both base rates and a combination of rate riders and applicable taxes. **Error! Reference source not found.** The Table below provides the detailed assumptions regarding the rate components. The customers served by the Municipal Utility would avoid the total TEP rate with the exception of cost stranding (discussed more below). Not all TEP rate components and riders apply to all customer classes.

TABLE 3-11. TEP RETAIL RATE COMPONENTS

Function	TEP Rate Component or Rider
Transmission	– Transmission Base Rate – Transmission Cost Adjustor – Energy Imbalance: Open Access Transmission Tariff (OATT)
Delivery/Distribution	– Customer Charges – Base Delivery Rate – Rider 2: Demand Side Management Surcharge – Rider 8: Lost Fixed Recovery Energy Efficiency and Distributed Generation – Rider 9: Environmental Cost Adjuster – Rider 17: Tax Expense Adjustor Mechanism[a]
Power Supply	– Base Power Supply – Generation Capacity Charges – Fixed Must Run – Ancillary Services – Rate 6: Renewable Energy Program Expense Recovery (REST) – PPAFC: power cost adjustor
Tax	– Arizona Independent Scheduling Administrator Assessment (AZISA) – Franchise Fee – Public Utility Tax – City Sales Tax (Tucson) – State Sales Tax

Function	TEP Rate Component or Rider
	− Arizona Corporation Commission Assessment − Residential Utility Consumers Office Assessment

(a) The TEAM rider accounts for income tax adjustments. Likely these adjustments apply, in part, to all functions, however, the impact is de minimis, so it is assumed to be included in the Delivery portion of the bill. This assumption impacts only the evaluation of the CCA program and is unlikely to impact the results due to the charge's relative size.

A forecast of TEP rates is needed in order to determine the feasibility of alternative options. The forecast begins with current rate levels based on the rate schedules provided on TEP's website. The schedules are applied to the average customer characteristics for each rate class based on TEP's 2022 Cost of Service analysis. Table 3-12 compares TEP unbundled rates with the revenue collected based on TEP 2023 FERC Form 1. TEP's system average rate was $0.147/kWh in 2023 and increased to $0.196/kWh in 2025. The 2025 average system rate is estimated based on TEP's published rate schedules and customer characteristics. The resulting average annual rate increase between 2023 and 2025 is 8.7% per year.

TABLE 3-12. TEP: CURRENT 2025 RATES EXCLUDING TAXES, $/KWH

	2025 Delivery Rate	2025 Power Supply Rate	Bundled Rate 2025 (a)	Bundled 2025 Rate with Taxes	TEP 2023 FERC Form 1 (b)
Residential	$0.063	$0.116	$0.179	$0.202	$0.165
Small General Service	$0.065	$0.121	$0.186	$0.210	$0.168
Medium General Service	$0.079	$0.113	$0.191	$0.216	$0.161
Large General Service	$0.074	$0.100	$0.175	$0.197	$0.129
Large Power	$0.021	$0.099	$0.120	$0.135	$0.103
Lighting			$0.144	$0.163	$0.170
Total System			**$0.173**	**$0.196**	**$0.147**

(a) Sourced from: https://www.tep.com/affordable-rates/
(b) Includes $140 million in Other Electric Revenue related to rate riders.[89] Equal to revenue divided by retail sales.

Delivery and power supply rates are forecast separately. TEP's future power supply rate is based on the revenue requirement from TEP's 2023 IRP. It is estimated that TEP's resource costs will increase by an average of 3.4% per year through 2038. The non power supply cost is escalated at the 7-year average inflation rate based on the Consumer Price Index for all urban consumers in the Pacific region. The average rate of inflation from 2017 to 2024 was 3.7% per year. Therefore, the bundled TEP retail rate is forecast to increase at an average rate of 3.5%.

[89] TEP FERC Form 1: Annual Report of Major Electric Utilities, Licenses and Others and Supplemental Form 3-Q: Quarterly Financial Report. March 19, 2024. page 119/228.

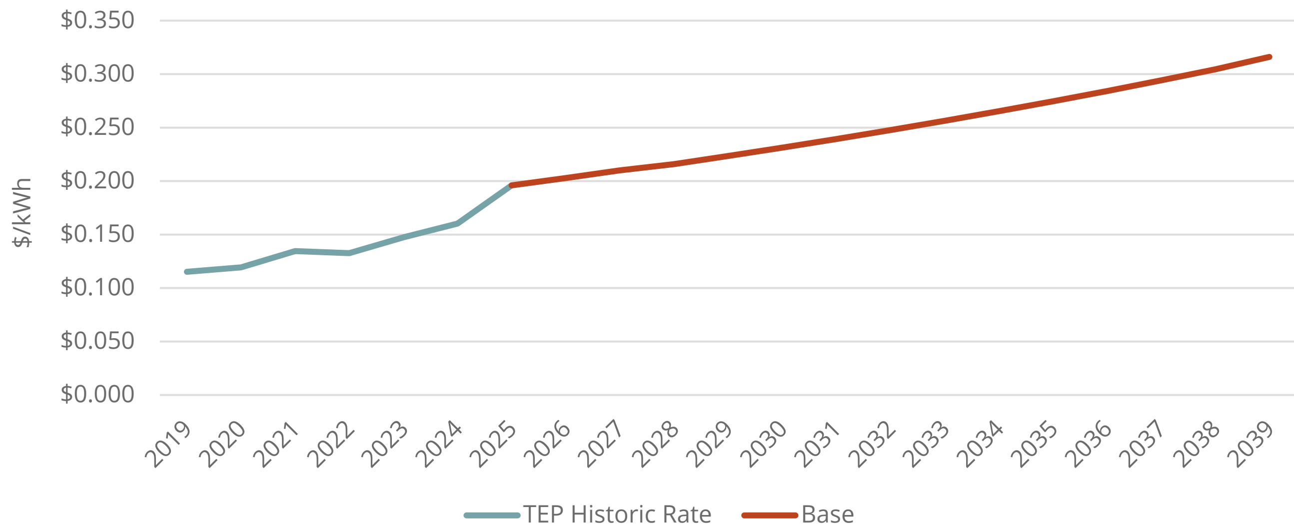

FIGURE 3-12. HISTORICAL AND FORECAST TEP SYSTEM RETAIL RATES

3.14 STRANDED POWER SUPPLY COSTS

Once the City forms a public power utility, City electric customers are responsible for their share of TEP's power supply costs stranded as a result of load departure. TEP would sell excess generation from its portfolio to recoup a share of the cost. The difference between TEP's resource costs and the market value of those resources is the stranded cost. The stranded cost estimate will change over time as market values fluctuate and TEP's resource portfolio changes. The components of the portfolio that are valued include:

1. ***Energy Value:*** valued at forecast market prices
2. ***Capacity:*** valued at forecast capacity price
3. ***Renewable Attributes:*** valued at unbundled renewable energy credit price.

For consistency with the power supply cost estimate, TEP assets are valued using the same assumptions. This means that in the case where power supply costs are higher for the municipal utility, the stranded cost estimate will also be adjusted using the higher value of TEP's resources.

TEP's future resource portfolio is based on its 2023 Integrated Resource Plan where TEP selected the Balanced Portfolio as the preferred option. In the Balanced Portfolio, TEP proposes to reach its goal of 100% GHG free energy by 2050 by adding wind, solar, battery storage, and distributed generation. TEP also proposes adding natural gas resources to meet capacity requirements. Figure 3-13 illustrates how TEP's renewable energy content is forecast through 2038 based on the IRP and then a straight-line forecast is extended to reach 100% renewable by 2050.

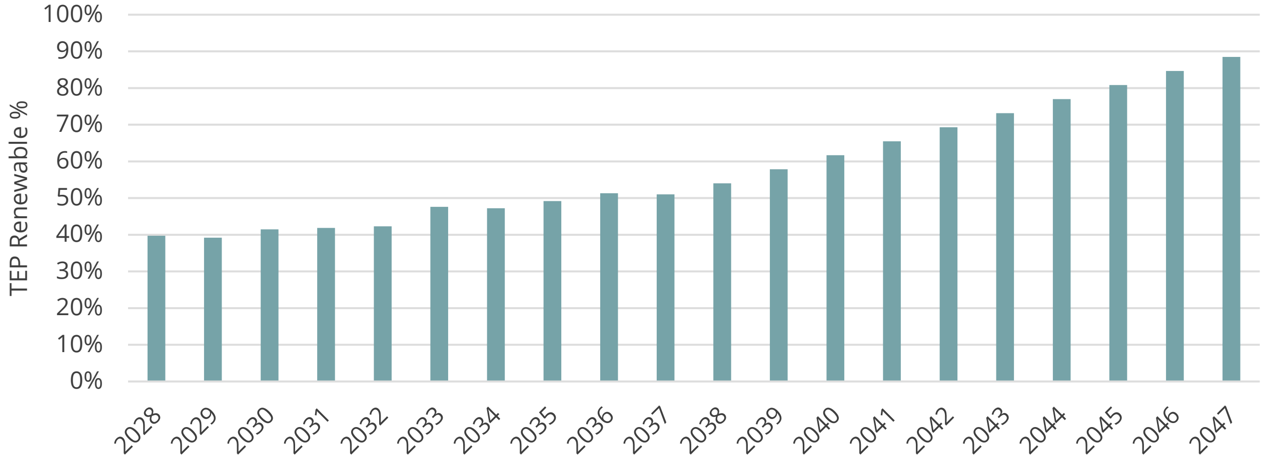

FIGURE 3-13. TEP PREFERRED PORTFOLIO, % RENEWABLE ENERGY

TEP will also need to meet capacity requirements as forecast in Figure 3-14. Capacity requirements beyond 2038 are forecast at an annual growth rate of 0.7%. TEP's resource portfolio will provide both the hourly energy requirements and peak capacity needs for the utility's retail load. Therefore, TEP's resources have both an energy value and a capacity value. The forecast below is valued at a capacity value of $120/kW-year escalated at inflation.

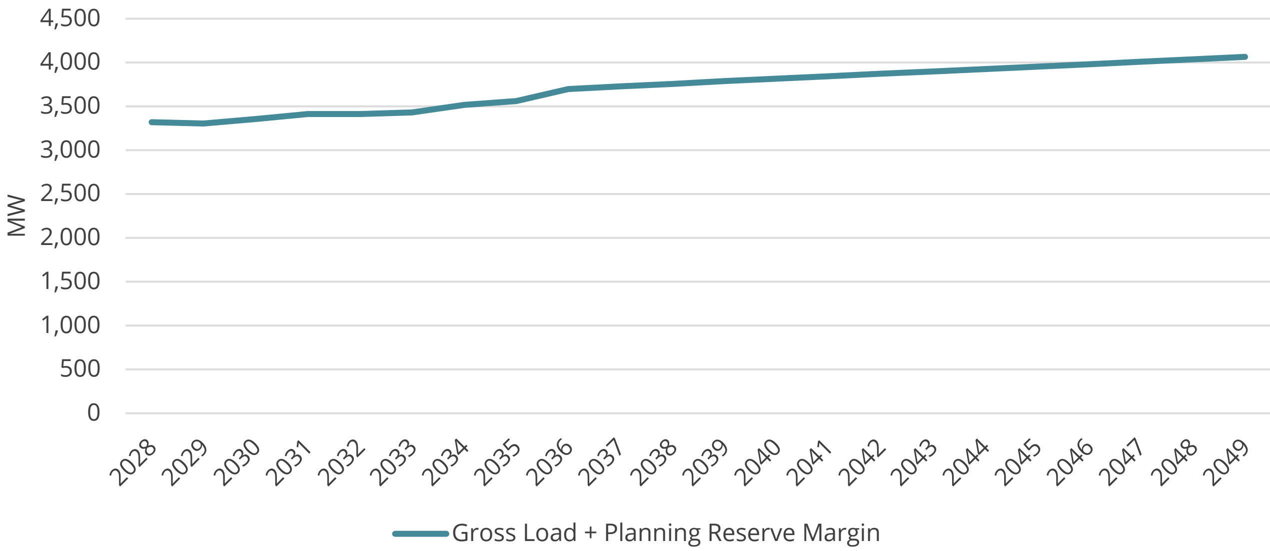

FIGURE 3-14. TEP CAPACITY REQUIREMENTS

The value of energy needed to serve TEP's load is based on the market price forecast described earlier. The renewable value for TEP's anticipated solar, wind, and distributed resources is based on forecast prices for unbundled renewable energy credits. The most often traded market for unbundled RECs is the California Market where these resources have been priced in the $6-$8/MWh range since 2021. California load serving entities have forecast 2025 unbundled RECs at $8/MWh. This value is conservatively used for 2028 and beyond.

TEP's 2023 IRP estimates the net present value of its future generation revenue requirement at $14.3 billion[90] or $95/MWh (wholesale) when levelized over the period 2024-2038.[91] To compare with current generation costs, TEP reported an average wholesale power cost of $75/MWh in its 2023 FERC Form 1 filing.[92]

After 2028, the $95/MWh is escalated at 5% annually after 2038 to represent increasing costs and changes to TEP's resource mix after 2038. This escalation rate is considered conservatively high based on declining cost of renewable capital costs. Non-renewable steam generation construction costs have increased by an average annual rate of 7% since 2015.[93]

Table 3-13 demonstrates the estimated stranded generation cost.

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[90]TEP. *2023 Integrated Resource Plan Dashboard Summary*. Page 2. Available online at: https://docs.tep.com/wp-content/uploads/TEP-Portfolio-Dashboard-Summary.pdf

[91] The net present value is estimated based on TEP's weighted average cost of capital of 7.31% reported in its general rate case application available at: https://docket.images.azcc.gov/E000019730.pdf?i=1728600575789.

[92] Calculated as (Total Production Expense - Wholesale Revenue + Production Depreciation Expense + 6.93% Rate of Return)/Retail Sales.

[93] Estimate based on the Handy-Whitman Index for the Plateau Region. Whitman, Requardt and Associates. *The Handy-Whitman Index of Public Utility Construction Costs.* Baltimore, MD. July 2024 edition.

TABLE 3-13. STRANDED GENERATION COST ESTIMATE

	TEP Portfolio Renewable Share	Energy Value, $/MWh Weighted Based on Load Shape	Renewable Value $/MWh	Unbundled REC Value Weighted for Renewable %	Resource Adequacy , $/MWh	Total Market Value, $/MWh	TEP Preferred Portfolio Cost, $/MWh	Stranded Cost, $/MWh	Stranded Cost $/Retail kWh
column	*a*	*b*	*c*	*d = a × c*	*e*	*f = b+d+e*	*g*	*h = g - f*	*i = h ÷ 1,000 ÷ (1-5%)*
2028	40%	$55.37	$8.00	$3.18	$26.86	$85.41	$95.36	$9.95	$0.010
2029	39%	$57.31	$8.00	$3.14	$27.09	$87.53	$95.36	$7.83	$0.008
2030	41%	$61.92	$8.00	$3.32	$27.93	$93.17	$95.36	$2.19	$0.002
2031	42%	$62.50	$8.00	$3.35	$28.49	$94.33	$95.36	$1.03	$0.001
2032	42%	$64.06	$8.00	$3.38	$27.93	$95.38	$95.36	-$0.02	$0.000
2033	48%	$65.66	$8.00	$3.81	$28.07	$97.54	$95.36	-$2.18	-$0.002
2034	47%	$67.30	$8.00	$3.78	$29.16	$100.24	$95.36	-$4.88	-$0.005
2035	49%	$68.99	$8.00	$3.93	$29.83	$102.75	$95.36	-$7.39	-$0.008
2036	51%	$70.71	$8.00	$4.11	$31.33	$106.15	$95.36	-$10.79	-$0.011
2037	51%	$72.48	$8.00	$4.08	$32.11	$108.67	$95.36	-$13.31	-$0.014
2038	54%	$74.29	$8.00	$4.32	$32.84	$111.45	$95.36	-$16.09	-$0.017
2039	58%	$76.15	$8.00	$4.63	$33.62	$114.39	$100.13	-$14.27	-$0.015
2040	62%	$78.05	$8.00	$4.93	$34.38	$117.36	$105.13	-$12.23	-$0.013
2041	66%	$80.00	$8.00	$5.24	$35.15	$120.39	$110.39	-$10.00	-$0.011
2042	69%	$82.00	$8.00	$5.55	$35.94	$123.49	$115.91	-$7.58	-$0.008
2043	73%	$84.05	$8.00	$5.85	$36.74	$126.64	$121.70	-$4.94	-$0.005
2044	77%	$86.16	$8.00	$6.16	$37.55	$129.87	$127.79	-$2.08	-$0.002
2045	81%	$88.31	$8.00	$6.47	$38.38	$133.16	$134.18	$1.02	$0.001
2046	85%	$90.52	$8.00	$6.77	$39.23	$136.52	$140.89	$4.36	$0.005
2047	89%	$92.78	$8.00	$7.08	$40.10	$139.96	$147.93	$7.97	$0.008

The above estimates rely on many assumptions and would likely be adjusted based on input from TEP as well as when market conditions change. Generally higher stranded cost values reduce the ability for the Municipal Utility to charge rates lower than TEP's rates. In addition, if the City were to purchase some of TEP's generating assets, those assets would no longer be part of the stranded cost adjustment. The construct of this study results in indifference between the City paying TEP the stranded cost adjustment or purchasing TEP assets at their market value.

3.15 NON-BYPASSABLE CHARGES: COAL PLANT RETIREMENT

Similar to stranded generation, City electric customers would need to compensate TEP's remaining customers for their share of TEP's coal plant retirement costs. This charge is already included in TEP's revenue requirement from the 2023 IRP. An estimate of the coal plant cost recovery is calculated below. These values are collected even when the stranded cost is lower than the coal rate. This adjustment is necessary since the physical retirement of the remaining coal plants occurs earlier than the currently approved cost recovery through retail rates. Once the plants are physically retired, there no longer exists an opportunity for TEP to sell the output on the market, yet TEP must still include cost recovery for these plants in its retail rates.

TEP provided details in the 2022 Rate Filing[94] about their 2022 Depreciation Study: net salvage reserve, dismantlement cost share, and retirement year by steam plant unit. The remaining un-recovered cost per unit is the difference between dismantlement costs and net salvage reserve. Years until retirement were factored in to result in the annual estimated recovered costs by unit. In some cases, the retirement year (full depreciation) for the purposes of rate making is different from the physical plant retirement. Future rate cases may allow TEP to recover plant costs in a shorter time frame; however, the most recent rate case is used as the basis for the cost stranding analysis.

Total retail sales were obtained from the EIA Form 861[95] for 2022-2023, and TEP's 2023 IRP[96] submission provided energy estimates for 2024 through 2038. The compound average growth rate (CAGR) for 2033 to 2038 of 0.7% from TEP's forecast was applied to determine energy for the remaining years through 2042. Estimated cost per kWh for coal plant retirement takes the estimated recovered costs, divided by annual retail energy.

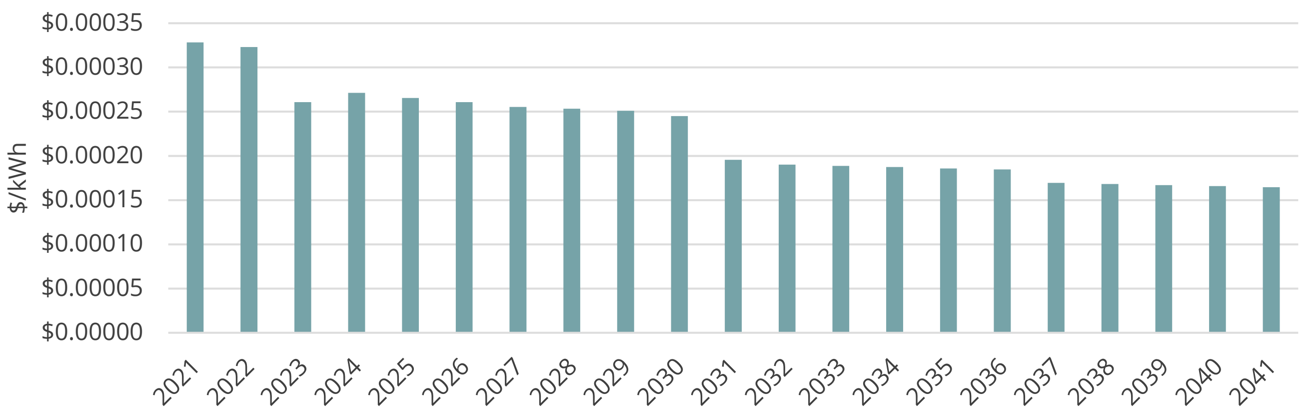

FIGURE 3-15. ESTIMATED COAL RETIREMENT COSTS, ($/KWH)

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94 "Docket Details E-01933A-22-0107", *Arizona Corporation Commission*, https://edocket.azcc.gov/search/docket-search/item-detail/26329

95 "Annual Electric Power Industry Report, Form EIA-861 detailed data files", *U.S. Energy Information Administration*, https://www.eia.gov/electricity/data/eia861/

96 "2023 Integrated Resource Plan", *Tucson Electric Power*, November 2023, https://www.tep.com/2023-irp/

The cost per kWh in 2024 is lower than 2023 because TEP's 2024 forecasted energy is 20% higher than the actual 2023 loads reported in EIA Form 861. Other unit cost ($/kWh) decreases correspond to coal plant retirement dates: Four Corners Units 4 and 5 are depreciated by 2031, Springerville Unit 1 is depreciated in 2037, and the remaining Springerville assets including Unit 2 are depreciated in 2042.

3.16 COMBINED STRANDED COSTS AND NONBYPASSABLE CHARGES

The feasibility construct conservatively assumes that TEP would not pay the public power utility in the case that its resources are valued greater than TEP's actual costs (negative stranded costs). This assumption builds upon the other conservative assumptions throughout the report to demonstrate the level of feasibility. While the study takes this approach, the reality is that TEP's City ratepayers should be compensated when stranded generation calculations results in a credit to them. This is because the City's ratepayers created the basis for, and have contributed to, the payment for all TEP's acquired generation resources. Therefore, it is justified that the City has a right to the value of its share of any generation assets. This is a parallel argument from which the City is obligated to compensate TEP in the event that the assets are negative in value relative to market.

Therefore, the combined stranded costs and non-bypassable charges are equal to the stranded cost (if positive) plus coal plant decommissioning costs. Based on forecast 2028 loads within the City, the annual cost to the utility is $50 million. The stranded cost is added to the public power utility's budget as an expense paid monthly to TEP.

3.17 PROFORMA RESULTS/RATE COMPARISON

The results of the feasibility assessment are summarized in Figure 3-16 below. The figure shows the average rate comparison between the public power utility and TEP. Negative values indicate that the public power utility rates are higher than TEP rates. Positive values indicate that the public power utility rates are lower than TEP rates. The results address the acquisition cost (in billions) and uncertainty in the power supply costs for the public utility.

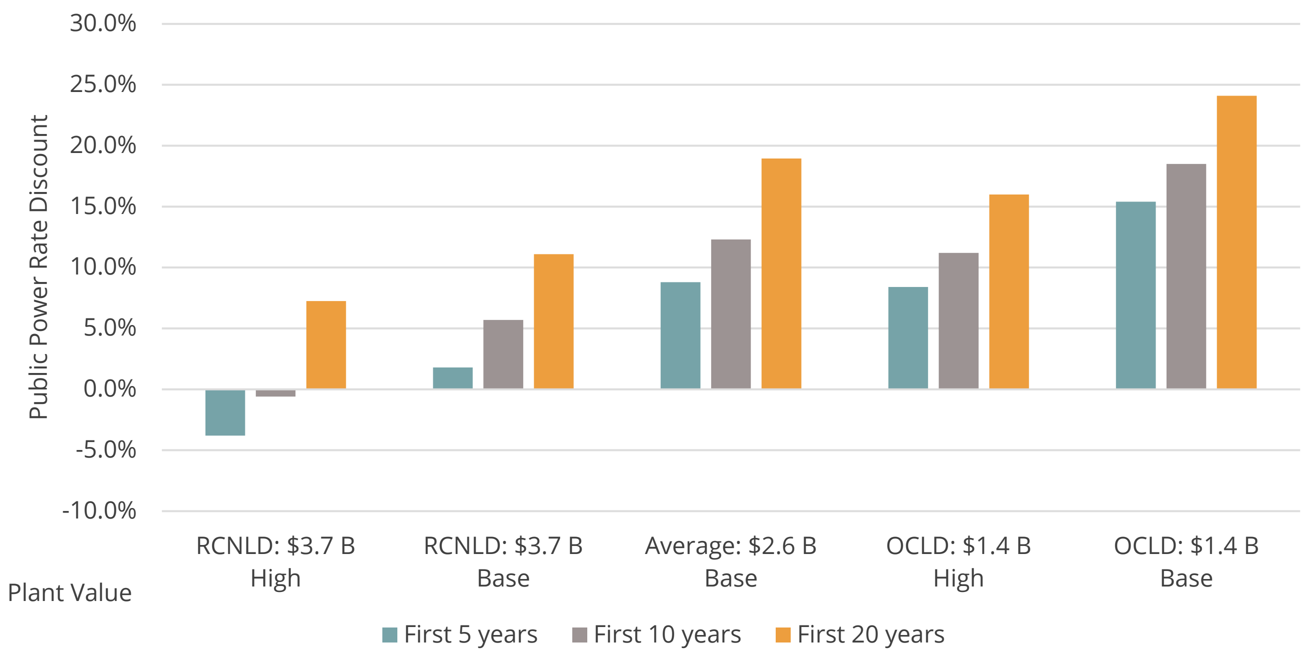

FIGURE 3-16. PUBLIC POWER FEASIBILITY RESULTS

The high power supply cost scenarios do not take into account the changes in TEP's stranded generation costs resulting from increased market values. The study conservatively presumes that if stranded costs are negative, TEP would not compensate the public utility. In practice, stranded cost credits (payments from the IOU to the public power entity) have been made since ratepayers have paid and provided the basis for the generating asset investments.

Additionally, high power costs would likely not be sustained for the 20-year period. Utilities operate in changing power supply environments. It is expected that power costs would be relatively high from time to time. The results show that even when paying the ceiling price of $3.7 billion for the system, the public power utility rates could still be below TEP rates after year 7 even if high power costs persist.

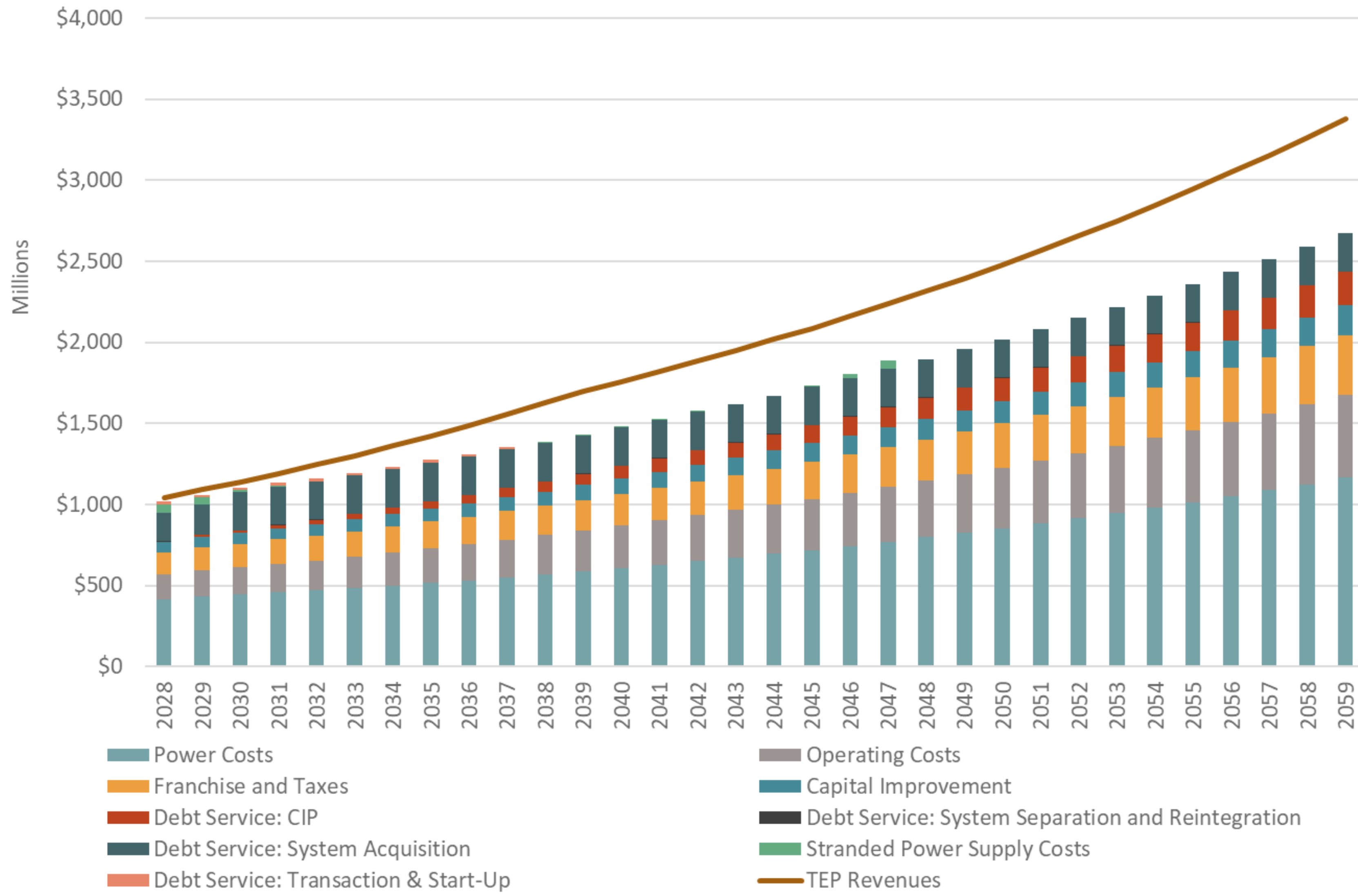

FIGURE 3-17. FEASIBILITY RESULTS: RCNLD AND EXPECTED POWER SUPPLY COSTS

3.18 FINDINGS

The City public power utility is feasible under most of the scenarios modeled. The value of the plant needed to serve customers in the City is likely between the two values presented in this study: $1.4 and $3.6 billion. A value within this range would result in rate savings to City electric customers. Figure 3-18 shows that the average residential customer using 9,000 kWh per year (750 kWh per month) would have the potential bill reductions of up to $241 per year within the first 5 years with the public power utility.

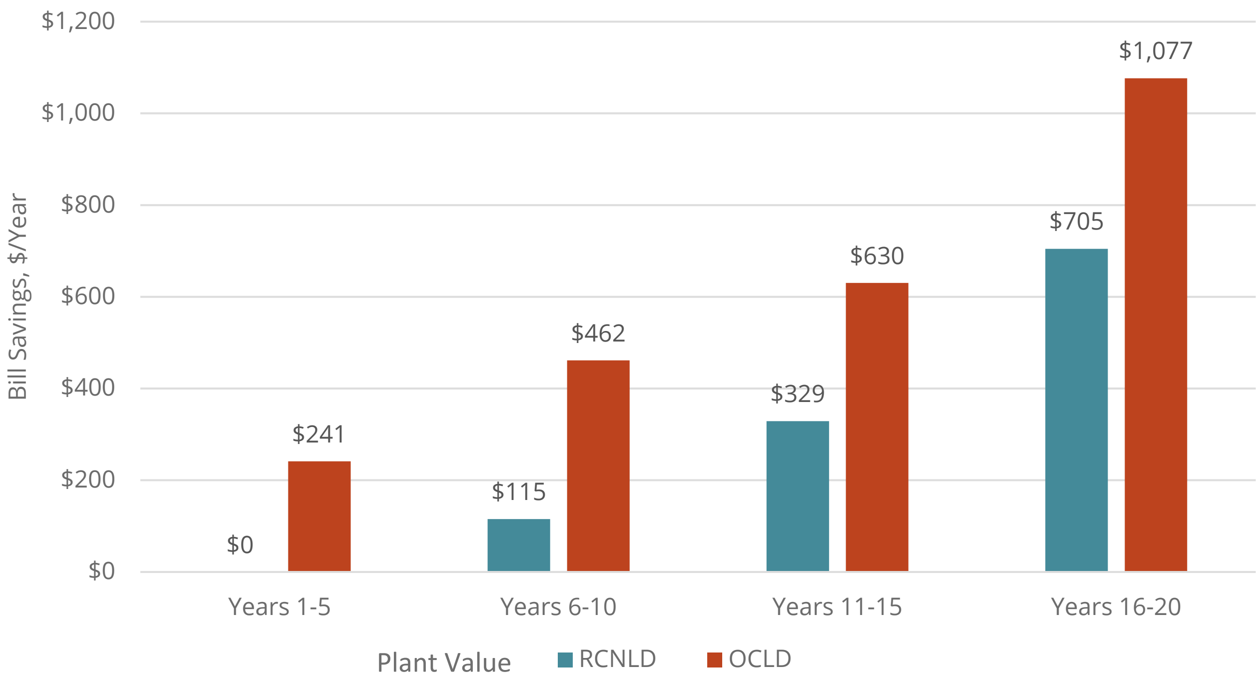

FIGURE 3-18. ESTIMATED RESIDENTIAL BILL SAVINGS, $/YEAR

The base case analysis assumes the public power utility would meet its goal of GHG neutral power supply for the entire City by 2045. The Accelerated Renewable scenario achieves this goal by 2035. The cost difference between the two portfolios is approximately 9% in the first 10 years. This cost difference is relatively small and it suggests that accelerating GHG neutrality goal could be feasible for the public power utility. Ultimately, the power supply portfolio would need to be continually evaluated by the public power utility's staff and governing board so that sustainability goals and rate levels are balanced.

04 Community Choice Aggregation Feasibility

4.1 WHAT IS COMMUNITY CHOICE AGGREGATION?

Community choice aggregation, also known as community choice energy or municipal aggregation, is a program that allows local governments (such as a city or county) to procure power on behalf of their residents and businesses, have it delivered through existing transmission and distribution electrical systems to customers, and establish customer rates (for power only). CCAs across ten states in the U.S. purchase this bulk power either directly from power suppliers and generators or from third-party power marketers. CCAs themselves or their power suppliers may coordinate delivery of power through utility transmission systems, while paying the appropriate tariffs. IOU distribution utilities then have the power delivered to CCA customers through their distribution systems. Distribution system charges are billed to and collected from CCA customers by the IOU. Figure 4-1 provides an illustration of how CCAs function within the traditional electric utility industry supply infrastructure.

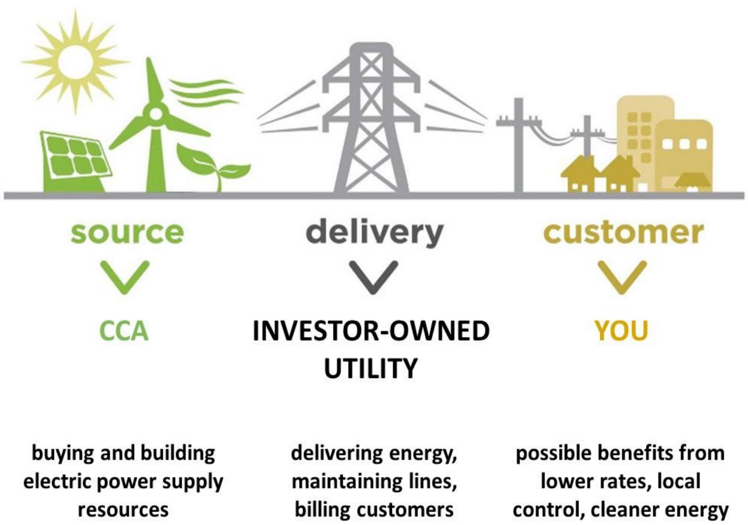

FIGURE 4-1. CCA BUSINESS MODEL CONSTRUCT

4.2 COMMUNITY CHOICE AGGREGATION IN ARIZONA

Community choice aggregation is not currently a viable option for Tucson. The regulation of competitive electric utility providers in Arizona is controlled by three principal bodies of law: the Arizona State Constitution, Arizona Revised Statutes, and Arizona Administrative Code. These are described below in detail. Ultimately these bodies of law would require significant changes before CCA in Arizona could be viable.

Lastly, a review of relevant cost stranding law is provided as it pertains to potential CCA in Arizona. The feasibility assessment (described later in this section) has been developed based on a cost stranding methodology consistent with the essence of the current law; however, the study does not go into great detail regarding cost recovery by each rate class. In other states, the IOU undertakes the analysis of cost recovery across the different rate classes. This work would be needed if a CCA program opportunity were enabled in the future.

4.2.1 The Arizona State Constitution

Article 15, § 3 of the Arizona Constitution grants the Arizona Corporation Commission (the Commission) full authority over electric utility ratemaking and allows the Commission to make and enforce reasonable rules regarding electric utilities.[97] The Arizona Supreme Court in *Johnson Utilities, L.L.C. v. Arizona Corporation Commission* describes the Commission's authority to set just and reasonable rates and charges as the Commission's "ratemaking authority" while the Commission's authority to make and enforce reasonable rules is described as the Commission's "permissive authority."[98] The Commission's ratemaking authority and permissive authority are distinct and unrelated.[99] The Commission's ratemaking authority is plenary and self-executing, meaning that it does not require legislative action to exercise its ratemaking powers.[100] In contrast, the Commission's rulemaking authority is permissive and exercised concurrently with the authority of the Arizona Legislature.[101] Furthermore, the Legislature has the authority to override the regulations of the Commission, and in the event that legislation conflicts with Commission rules promulgated under its permissive authority, the legislation controls.[102]

4.2.2 Legislation and the Arizona Revised Statutes

While the Commission had explored rules to establish competition in the Arizona electric utility market as early as 1996,[103] the Arizona Legislature fully opened the state's vertically integrated monopoly electric utility market to competition by statute on May 29, 1998 when House Bill (HB) 2663, known as the Electric Competition Act (ECA), was signed into law. In 2022, however, the enabling language of the ECA that allowed competition in the electricity market was removed from the Arizona Revised Statutes (A.R.S.) by HB 2101, enacted on April 26, 2022. Among other provisions, HB 2101 specifically removed the statutory language added by the ECA that had declared that it was Arizona public policy to have a competitive retail electricity market.[104] HB 2101 also removed statutory language that previously authorized the Commission to permit CCA programs.[105]

Specifically, HB 2101 removed A.R.S. § 40-202(B) regarding supervising and regulating competitive public service corporations; § 40-202(C)(7) regarding customer aggregation; § 40-207 regarding rules for electricity suppliers; §

[97] Ariz. Const. art.15 § 3, stating: "The corporation commission shall have full power to, and *shall*, prescribe just and reasonable classifications to be used and just and reasonable rates and charges to be made and collected, by public service corporations within the state for service rendered therein, and make reasonable rules, regulations, and orders, by which such corporations shall be governed in the transaction of business within the state, and *may* prescribe the forms of contracts and the systems of keeping accounts to be used by such corporations in transacting
such business, and make and enforce reasonable rules, regulations, and orders for the convenience, comfort, and safety, and the preservation of the health, of the employees and patrons of such corporations."

[98] *Johnson Utilities, L.L.C. v. Arizona Corporation Commission*, 249 Ariz. 215, 468 P.3d 1176, 1181-1182 (2020) which states: "The first clause of section 3, which describes the Commission's authority to "prescribe just and reasonable classifications . . . rates and charges" for PSCs is referred to as the Commission's "ratemaking authority." The second clause describes the Commission's power to regulate PSCs to protect the health, safety, comfort, and convenience of their customers, employees, and the public, and is referred to as the Commission's "permissive authority"

[99] *Johnson Utilities* at 1183, stating: "The Commission's permissive authority is distinct from, and unrelated to, its ratemaking powers."

[100] *Johnson Utilities* at 1182, stating: "The Commission's ratemaking authority under article 15, section 3 is plenary. . .ratemaking authority is also self-executing. Specifically, because section 3 grants the Commission authority to make rules, regulations and orders, no legislative action is necessary to enable the Commission to exercise its ratemaking powers."

[101] *Johnson Utilities* at 1183, stating: "The Commission's permissive authority is also not exclusive. The permissive clause does not, either expressly or impliedly, limit or divest the legislature of its police power to protect the health, safety, and welfare of the public."

[102] *Johnson Utilities* at 1183, stating: "when there is a conflict between a Commission regulation and a statute, the legislature's police authority is "paramount," meaning it has the authority to override the regulations of the Commission."

[103] See Arizona Administrative Code (A.A.C.) R14-2-1601 et seq. Adopted effective December 26, 1996, under an exemption as determined by the Arizona Corporation Commission (Supp. 96-4). Current through rules published in Arizona Administrative Register Volume 31, Issue 12 March 21, 2025.

[104] Former A.R.S. § 40-202(B) which states: "It is the public policy of this state that a competitive market shall exist in the sale of electric generation service"

[105] Former A.R.S. § 40-202(C)(7) which states: "7. Permit the aggregation of loads by multiple customers."

40-208 regarding the opening of service territories to competition, and large portions from other sections of the A.R.S. which made any reference to a competitive electric market.[106]

Section 40-202(B) previously contained the enabling language allowing a competitive electric generation market that was to be regulated by the Commission under its permissive authority. This section stated:

> *"It is the public policy of this state that a competitive market shall exist in the sale of electric generation service. In order to transition to competition for electric generation service, the commission's authority is confirmed to: . . ."*

The statute then provided an extensive list of regulatory activities which the Commission was authorized to undertake. Those activities included:

- Opening the full service territories of incumbent vertically integrated electric utilities and co-ops to competitive access.[107]
- Establishing requirements for certificating and regulating competitive electricity suppliers.[108]
- Maintaining the current service territory boundaries for electric distribution service.[109]
- Requiring incumbent electric distribution utilities to provide billing and collections services for competitive electric generation providers.[110]
- Requiring incumbent electric distribution utilities to act as the provider of last resort (POLR).[111]
- Providing for the recovery of just and reasonable electric distribution costs.[112]
- Investigating and imposing sanctions on subsidization of competitive services by any regulated rate or charge for any noncompetitive electric service.[113]
- Decoupling the regulation of electric distribution cost recovery from electric generation cost recovery, except as provided for the recovery of stranded costs.[114]

Section 40-202(C)(7) had also confirmed the Commission's authority to adopt rules to "permit the aggregation of loads by multiple customers." This is the only existing instance which references the concept of aggregation of customer load in the A.R.S., and it clearly refers to a CCA program. By explicitly removing this section of the A.R.S., the Arizona Legislature clearly stated that the Commission should not take regulatory action to permit the aggregation of customer load such as a CCA.

Section 40-207 had established that competitive electric suppliers must obtain a certificate of convenience and necessity from the Commission prior to offering retail electric sales to customers, and directed the Commission to adopt rules providing minimum standards of disclosure and complaint procedures. The statute authorized, but did not require, the Commission to adopt, amend and repeal rules regarding certificates of convenience and necessity, and to impose conditions such as reports, bonds, and deposits on certification of competitive electric suppliers in order to assure their financial stability. By explicitly removing this section of the A.R.S., the Arizona Legislature clearly stated that the Commission should not issue certificates of convenience and necessity to competitive electric suppliers such as CCA.

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[106] *See also* A.R.S. §§ 9-520, 40-201(3), 40-202(D), 40-202(M), 40-202(C)(2), 10-2057(A)(4), 10-2081, and 10-2127(A)(5).
[107] Former A.R.S. § 40-202(B)(1)
[108] Former A.R.S. § 40-202(B)(2).
[109] Former A.R.S. § 40-202(B)(3).
[110] Former A.R.S. § 40-202(B)(4).
[111] Former A.R.S. § 40-202(B)(5).
[112] Former A.R.S. § 40-202(B)(6).
[113] Former A.R.S. § 40-202(B)(7).
[114] Former A.R.S. § 40-202(B)(8).

Section 40-208 had established that once a competitive electric supplier had obtained a certificate of convenience and necessity from the Commission, it was eligible to offer services in any incumbent utility's territory. The Arizona Legislature removed this section.

In removing the Commission's authority, HB 2101 effectively closed the door on retail electric competition activities. While the ECA had at the time clearly allowed the Commission to promulgate rates and rules enabling retail electric competition, such as CCA, HB 2101 reversed that authority. In the absence of state legislation allowing retail electric competition, there is not an existing statutory pathway to form a CCA.

4.2.3 Arizona Administrative Code

Arizona Administrative Code (A.A.C.) §§ R14-2-1601 through R14-2-1618 are Commission administrative rules that address retail competition. The rules were adopted on December 26, 1996 under a Commission exemption (Supp. 96-4), amended numerous times between August 1998 and October 2000, and are currently published in Arizona Administrative Register Volume 31, Issue 12 March 21, 2025. The rules addresses key issues that must be resolved for the success of a competitive retail electric generation market. Those issues include:

- The opening of electric utility service territory to competition[115]
- Certificates of convenience and necessity[116]
- Phasing and timing of competitive service offerings[117]
- Requirements for offering competitive services[118]
- Services that shall be offered[119]
- Recovery of stranded costs[120]
- System benefits charges[121]
- Equal transmission and distribution access[122]
- In-state reciprocity[123]
- Establishing rates and tariffs[124]
- Service Quality, Consumer Protection, Safety, and Billing Requirements[125]
- Reporting Requirements[126]
- Administrative Requirements[127]
- Decoupling of monopoly services from competitive services[128]
- Utility code of conduct[129]
- Disclosure requirements for pricing and generation resources[130]
- Environmental Portfolio Standard surcharge tariff[131]

[115] R14-2-1602.
[116] R14-2-1603.
[117] R14-2-1604.
[118] R14-2-1605.
[119] R14-2-1606.
[120] R14-2-1607.
[121] R14-2-1608.
[122] R14-2-1609.
[123] R14-2-1610.
[124] R14-2-1611.
[125] R14-2-1612.
[126] R14-2-1613.
[127] R14-2-1614.
[128] R14-2-1615.
[129] R14-2-1616.
[130] R14-2-1617.
[131] R14-2-1618.

Although these rules are currently published, they are outdated. The rules would require significant updates to reflect current conditions and prices, as well as subsequent Commission proceedings in order for them to be successfully utilized in implementing a competitive electric generation services market today.

Furthermore, in *Phelps Dodge Corp. v. Ariz. Elec. Power Co-op, Inc*., the validity of the rules and the Commission's authority to issue them were challenged by a group of affected utilities, electric cooperatives, the Arizona Consumers Council, and other plaintiffs.[132] The Arizona Court of Appeals found that while certain rules (R14–2–1602, –1607, –1613, –1615(B), and –1616) were promulgated under the Commission's plenary ratemaking authority and were therefore valid and lawful, certain other rules (R14–2–1603, –1605, –1609, –1610, –1612, –1614, and –1617) required certification by the Arizona Attorney General and were invalid because the Commission had not submitted those rules for certification.[133]

4.2.4 Stranded Costs for Retail Competition in Arizona

Stranded costs are the difference between the net original cost of assets necessary to furnish electricity, such as generating plants and fuel contracts, and the market value of such assets as affected by the introduction of competition in the market. These stranded costs include the above-market costs of longer-term energy generation contracts that an incumbent utility entered into but which it no longer needs once customers move to a competitive retail electric generation supplier such as a CCA. Often, the customers of a CCA pay a monthly charge for the costs remaining to the incumbent utility for power purchased or generation constructed on that customer's behalf. Such charges or "exit fees" are established to protect the remaining incumbent utility customers from paying for the costs of the departing customers.

Commission regulation A.A.C. § R.14-2-1607 addresses stranded costs. Although the regulation is still current, it is somewhat moot without a legislative mechanism to create a competitive entity where stranded cost would apply. To the extent it is applicable to departing load, under the rule, an affected utility must take every reasonable, cost-effective measure to mitigate or offset their stranded costs by reducing costs, expanding wholesale or retail markets, or offering a wider scope of permitted regulated utility services for profit.[134] In other words, an affected utility has a duty to mitigate its expenses. The rule requires affected utilities to file estimates of their stranded costs and request Commission approval to recover those costs via distribution charges, and may propose a discounted stranded cost exit methodology that a consumer may choose to use in lieu of monthly distribution charges, *i.e.*, a "buy-out."[135] After analysis and a hearing, the Commission determines the magnitude of the affected utility's stranded cost and an appropriate recovery mechanism based on at least the following factors:[136]

1. The impact of stranded cost recovery on the effectiveness of competition;
2. The impact of stranded cost recovery on customers of the affected utility who do not participate in the competitive market;
3. The impact, if any, on the affected utility's ability to meet debt obligations;
4. The impact of stranded cost recovery on prices paid by consumers who participate in the competitive market;
5. The degree to which the affected utility has mitigated or offset stranded cost;
6. The degree to which some assets have values in excess of their book values;
7. Appropriate treatment of negative stranded cost;

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[132] *Phelps Dodge Corp. v. Ariz. Elec. Power Co-op, Inc*., 207 Ariz. 95 (App. 2004).
[133] *Phelps Dodge Corp* at 129.
[134] A.A.C. § R.14-2-1607(A).
[135] A.A.C. § R.14-2-1607(C), (D).
[136] A.A.C. § R.14-2-1607(E).

8. The time period over which such stranded cost charges may be recovered. The Commission shall limit the application of such charges to a specified time period; and
9. The applicability of stranded cost to interruptible customers.

A Competition Transition Charge (CTC) may also be assessed on all retail customers on the amount of generation purchased from any supplier. Any reduction in electricity purchases from an affected utility which can be attributed to any causes other than competitive retail access, such as demand management or self-generation (*e.g.*, solar), is not able to be recovered as a stranded cost.[137] Affected utilities are required to recover stranded costs from the same rate class of customers responsible for those stranded costs, and are not allowed to use the CTC for double recovery of costs.[138] The Commission may also consider securitization as a financing method if it will result in lower costs to customers.

4.3 CCA IN OTHER STATES

CCA programs exist in several other states. Some states have enabling legislation but no programs (Virginia), while other states have a range of programs. Much of the information in this section is available directly from LEAN Energy US (LEAN). LEAN is a national 501(c)3 non-profit organization dedicated to accelerating the country's transition to clean and renewable power, supporting competition and customer choice in the energy sector, and maintaining affordable electricity rates. In this role, LEAN has collected operating data, state CCA development milestone activities, and descriptions of CCA programs in states where CCAs are operating. Other information sources come from each State's energy regulatory agency website describing Community Choice Energy programs.

Should the City decide to take a position on CCA development and wish to engage in legislative and regulatory activities for the formation and direction of CCA in AZ, the LEAN website provides a wealth of additional information in support of such a position.

4.3.1 CCA Operating Characteristics

There are currently 10 states with CCA available: California, Illinois, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Ohio, Rhode Island, and Virginia. Currently, CCA-enabling legislation does not exist in the State of Arizona. Other States who are considering or have considered CCA legislation include Colorado, Michigan, New Mexico, and Pennsylvania.

Table 4-1 compares key CCA operating characteristics across states where CCA is enabled. Note that while CCA legislation was enacted at a certain date, most states have since passed additional legislation to further define or modify CCA regulations. In all cases, communities allowed to participate in a CCA include counties, cities, townships, and unincorporated communities.

Table 4-2 describes program participation as either opt-in or opt-out. For opt-in programs, customers must proactively join the CCA and may opt out later. Opt-out customers are automatically enrolled into the CCA and must proactively opt out if they don't desire CCA service. The opt out program design is a critical factor for CCA operations. Opt-out programs generally have higher participation levels and can benefit from economies of scale.

Additionally, whether or not a state has a Direct Access (DA) program can influence CCA programs. DA means the state allows energy supplier competition and third parties exist to supply energy to customers outside of the IOU. Note that DA does not exist for municipal utility customers. Where DA programs are allowed, customers already have choice and are not required to be served by a utility. However, a CCA program would present customers with another choice outside of the IOU.

[137] A.A.C. § R.14-2-1607(F).
[138] A.A.C. § R.14-2-1607(H).

The Tables below delineate between programs that require CCAs to purchase power supply from licensed power sellers or through an open market. The ability to purchase power supply directly from an open market is a key benefit to CCA programs. Additionally, some states require power contract term limits for wholesale power supply. Contract term limits or requirements are important in that longer-term contracts typically result in lower prices for power. However, longer term power supply contracts pose risk if customers opt out in great numbers or are voluntarily returned to default IOU service.

The administrative model for CCA program operation differs across states as well. The administrative models include Public Entity where individual CCAs administer operations themselves as non-profit organizations, JPA where multiple communities form a single CCA through JPA agreement, Private Entity where CCA programs are administered by a for-profit company.

Finally, the formation of a CCA program is legally created through different actions. Either the local elected officials (e.g., city councils, county boards) vote to approve a program or a community-wide vote is held. This is important to CCAs as forming a CCA should be easier through an elected body vote versus a community-wide vote. While elected official action is likely an easier method to enable a program, it should be noted that in Ohio, where ballot vote is required, there is significant CCA program participation (46% of the State's total customers).

TABLE 4-1. STATE-BY-STATE COMPARISON OF CCA PROGRAM DESIGN

Data As of	State	Year CCA Enacted	Number of Active Communities	Service Accounts (1,000s)	Share of Statewide Customers	Annual Load, GWh	Program Participation	Eligible Customer Class	Direct Access State
2023	CA	2002	729	6,100	38%	61,800	Opt-Out	All	partial
2022	OH	1999	354	2,300	46%	19,400	Opt-Out	Residential, Small Business	yes
2022	MA	1997	144	1,130	41%	7,000	Opt-Out	All	yes
2022	IL	2012	379	734	14%	78	Opt-Out	Residential, Small Business	yes
2022	NY	2014	101	352	5%	1.5	Residential & Small Business: Opt-Out Large Business Opt-In	All	yes
2024	NH	1996	46	78	15%	1	Opt-Out	All	yes
2023	RI	1996	7	100	23%	0.85	Opt-Out	Residential, Small Business	yes
2022	NJ	1999	1	33	4%	0.5	Residential: Opt-Out Non-Residential: Opt-In	All	yes
2023	VA	1999	0	0	0%	0	TBD	All	yes
2023	MD	2021	0	0	0%	0	Opt-Out	Residential, Small Business	yes

TABLE 4-2. STATE-BY-STATE COMPARISON OF CCA PROGRAM DESIGN

State	Power Market Operations Model	Program Administration Model	Legal Creation Mechanism	Power Contract Term Limit
CA	Open Market	Public Entity, Joint Powers Authority (JPA)	Local Approval by Elected Officials	None
OH	From Licensed Sellers Only	JPA, Private Entity	Ballot Vote	Annual
MA	From Licensed Sellers Only	JPA, Private Entity	Local Approval by Elected Officials	None
IL	From Licensed Sellers Only	JPA, Private Entity	Ballot Vote	2 Years
NY	From Licensed Sellers Only	JPA, Private or Public Entity	Local Approval by Elected Officials	1-3 Months
NH	Open Market	Public Entity, JPA	Local Approval by Elected Officials	3-30 Months
RI	Open Market	Private Entity	Local Approval by Elected Officials	None
NJ	Open Market	Public Entity, JPA	Local Approval by Elected Officials	None
VA	TBD	TBD	Local Approval by Elected Officials	TBD
MD	TBD	TBD	Local Approval by Elected Officials	TBD

The list below summarizes some of the recent trends in the CCA enabled states:

- **CA:** Direct Access is currently limited and is being phased out as the CA Public Utility Commission has deemed that DA does not meet its goals for 100% carbon-free power by 2045.
- **NH:** Initially mandated opt in for all customers, in 2019 NH transitioned to opt out status.
- **RI:** Currently all CCAs contract with a private company for power supply and administration under 56-month contracts.
- **NJ:** Initially mandated opt in for all customers, in 2023 transitioned to current opt out/in status as noted.
- **VA:** CCA is legally enabled. No participants as of yet. Loudon County conducted Feasibility Study in 2022.
- **MD:** Pilot program in Montgomery County is authorized by state and is planned for service not earlier than June 2026.

4.3.1.1 Analysis of Statistics and Operating Characteristics

Judging CCA performance solely by annual load served, number of active communities, and total accounts, the following characteristics stand out as common to those higher performing CCAs:

- The more customer types that are automatically enrolled and may opt out later produces higher performance numbers.
- Having all customers eligible for CCA service is important to higher performance in combination with opt-out status.
- Having customer choice in electric supply is important to CCA. All CCAs operate in Direct Access states where customer choice is available outside of utility service. California's situation is unique in that Direct Access is capped.
- Local approval by elected vote would seem more advantageous than approval by all voters, but OH and IL have high performance numbers even with a ballot vote.
- As noted earlier, longer-term power contracts typically produce lower prices. Some states mandate contract terms. But also, CCAs sometimes opt for shorter-term contracts due to increased risk of holding longer-term contracts should customers leave.

4.3.1.2 Additional Comments on CCA Operations

For the most part, all of these CCAs were legislatively enabled and operate under an objective to provide lower customer rates and/or supply more renewable energy to customers and the states in which they operate. Below are general statements about rates and renewable energy supply applicable to operating CCAs in other states.

CCAs in other states typically offer lower energy rates than utilities or market competitors. The LEAN website as described above provides CCA rates compared to utility rates or other state-mandated benchmark energy rates. Also, CCA rates compared to utility rates are required to be provided on CCA websites. At times, CCA rates are higher than utility or market rates. Customers have the option to return to utility service or choose another supplier. In the case of California CCAs, they have the option of utilizing financial reserves to maintain rates equal to or lower than utility rates through rate subsidies to customers. Because of this many CCAs in states other than California have ceased operations. In California, only two CCAs have ceased operations.

CCAs typically offer power supplies with higher levels of renewables. This is especially prevalent in California where CCA initially grew through a desire for providing renewables in greater amounts than utilities provided under the state's mandate for achieving greenhouse gas free power by 2045. In some cases, renewable energy options are offered at rates lower than the standard IOU rate; again in California where the state mandate drives higher renewable production and also in New York. In other cases, the rates for higher renewable energy content power supply is priced higher than the standard IOU rate; e.g. in Massachusetts, Some states require that all or a portion of the renewable requirement must be procured within that state. Some CCAs offer renewable rates using unbundled RECs (i.e., RECs purchased separately from their power source – or unbundled). Again, all this information may be found at the LEAN website which also provides weblinks to all CCAs in these states.

4.4 CCA FEASIBILITY FRAMEWORK/METHODOLOGY

CCA is not currently enabled in Arizona. Therefore, the feasibility of a potential City of Tucson CCA program is analyzed based on models from other states. GDS has performed dozens of CCA feasibility studies on behalf of cities and counties throughout the country. GDS' feasibility study methodology follows these fundamental elements:

1. A potential CCA is deemed feasible if revenues generated by the CCA are equal to or greater than operating costs.
2. CCA revenues are generated from the electric rates charged and collected from the CCA customers. For the feasibility study, CCA rates are set equal to, or lower than, TEP rates to establish the potential amount of CCA revenues.
3. CCA operating costs are split into two major components: power supply costs and non-power costs. Power supply costs are estimated and forecasted from public and proprietary industry sources. The power supply costs from the City public power feasibility are used to develop CCA power cost estimates. Non-power costs are estimated from examples of past studies and existing CCAs operations.
4. The feasibility of a CCA program is determined over a 10-year period. The period includes initial costs as well as long-term and on-going revenues and expenses required for CCA operation.
5. A sensitivity analysis is performed to evaluate CCA financial feasibility under a conservative variance of input assumptions.

Because GDS has performed the City public power utility feasibility study using data provided by and ascertained for TEP regarding their power supply costs, non-power costs, TEP customer energy usage profiles, and forecasted customer rates; the determination of the energy rate component for TEP customers is the same for the City CCA analysis. The City CCA rates are then determined using the power supply costs and non-power costs needed to determine whether the City CCA is financially viable.

The assumptions used in the City public power utility and CCA feasibility studies are shown in Table 4-3 below.

TABLE 4-3. FEASIBILITY STUDY KEY INPUT ASSUMPTIONS

Factor	Description
CCA Power Supply Costs	The cost of power supply inclusive of renewable energy purchases, capacity and energy needs. Costs are based on data from recent contracts executed by power producers and projections of future market prices.
CCA Non-Power Supply Costs	Administrative costs (labor and overhead, office expenses, general administration, legal and regulatory), CCA start-up costs (labor, fees), financing costs for line of credit and power supply collateral.
Non-Bypassable Charges (TEP Rate)	Charges due to TEP which are required to be paid by customers regardless of power supply provider (CCA or TEP). Coal plant retirement costs are assumed to be non-bypassable.
Stranded TEP Generation (TEP Rate)	A non-bypassable charge for each CCA customer that reimburses TEP for power contracts procured to their benefit by TEP. The stranded cost do not negatively impact the remaining TEP customers due to customer migration to CCA service.

Factor	Description
TEP Power Supply Rate (Generation)	TEP generation rates are forecasted in the future as part of the Study. This metric is compared to the CCA rate.
CCA Rate	The rate for energy-only that would be charged by the CCA to recover its operating and non-operating costs.
Opt-Out Rate	CCA customers have the option to not receive service from the CCA by opting-out. The opt-out rate refers to the percentage of eligible customers who opt out of CCA service. Conversely, participation rates are the share of customers who are automatically enrolled and continue to be served by the CCA.

4.5 CCA BUDGET

4.5.1 Power Supply

Power supply for the City CCA is determined as was described in Section 3.8.1 of the City public power feasibility study analysis and represents resource strategy, projected power supply costs, and resource portfolios based on the City of Tucson's projected CCA loads.

Long-term resource planning involves load forecasting and power supply planning on a 10- to 20-year time horizon. This analysis focuses on a 10-year study period. Prior to launch, the City CCA planners would develop integrated resource plans (IRPs) and associated procurement strategies that meet their supply objectives and balance cost, risk, and environmental considerations. Integrated resource planning also considers demand side energy efficiency, demand response programs, and non-renewable supply options. The City CCA would require staff or a consultant to oversee planning even if the day-to-day supply operations are contracted to third parties. This staff or consultant would ensure that local preferences and objectives regarding the future composition of power supply and demand side resources are planned, developed, and implemented.

4.5.1.1 Portfolio/Resource Strategy

The City CCA's electric portfolio would be guided by the City CCA policymakers with input from its portfolio manager, scheduling coordinator, and other power supply experts. The scheduling coordinator would obtain enough resources each hour to serve all the City CCA customer loads. The City CCA policymakers would guide the power supply acquisition philosophy to achieve the City CCA's policy objectives. The baseline power portfolio analyzed for the City of Tucson CCA feasibility includes the following:

- ***Base Case:*** Achieves 50% renewable energy supply in 2028 and 100% by 2045.
- ***Accelerated Renewables:*** Achieves 50% renewable energy supply in 2028 and 100% by 2035.

It should be noted that City CCA policymakers, as part of their resource planning due diligence, could investigate other portfolios. Depending on the results of analyses prepared closer to time of procurement, City CCA policymakers may opt for other resource portfolios. However, the following baseline portfolio provides a reasonable estimate of costs for power supply that would meet the needs of the residents and businesses served by the City CCA.

4.5.1.2 Power Costs

Power supply costs are identical to those described in detail under the City public power utility section of this report. City CCA power costs exclude transmission and distribution costs since City CCA customers will continue to pay for this service via the TEP delivery rate. Figure 4-2 shows the power cost estimate. Total annual power supply costs are estimated at $388 million in the first year, escalating to $503 million by year 10. These total costs incorporate the 90% program participation assumption (90% of both customer accounts and load).

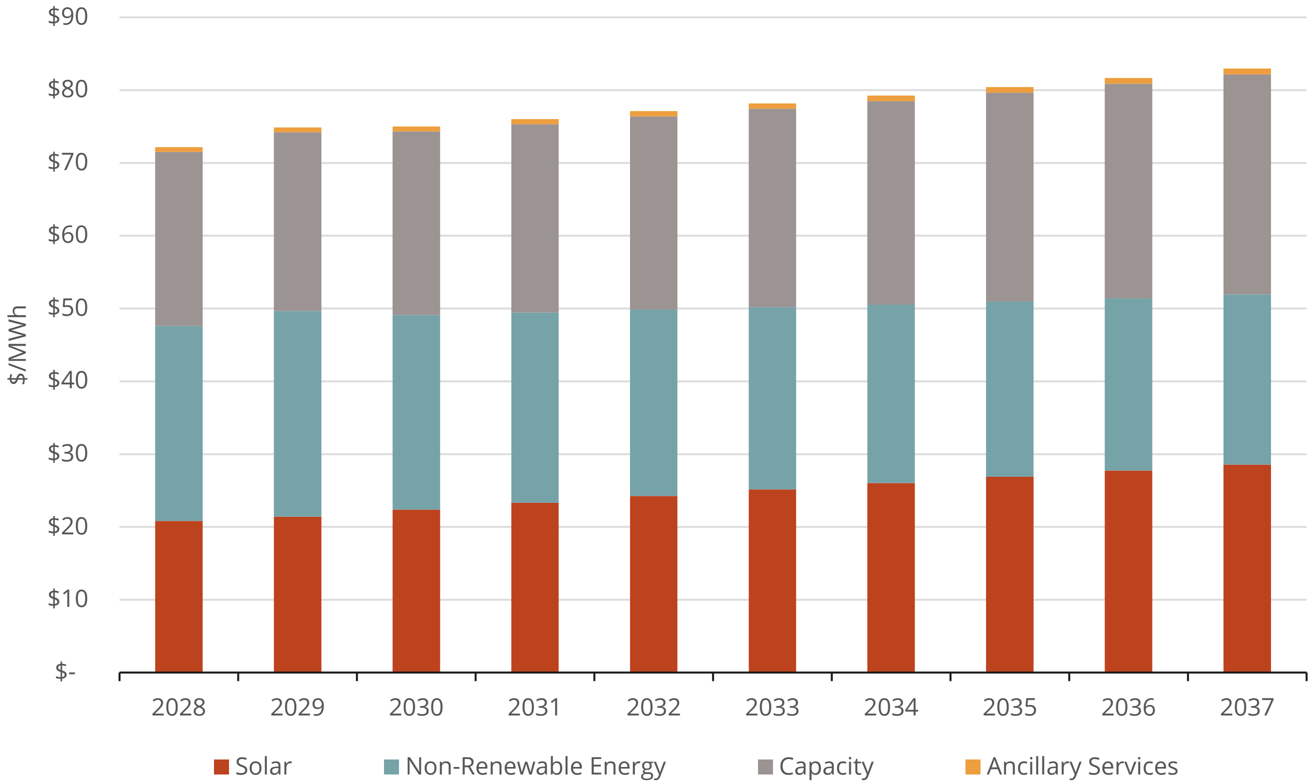

FIGURE 4-2. BASE CASE CCA POWER COST FORECAST

4.5.2 Other Operating Costs

The City CCA non-power supply, or other operating costs, are described in further detail here and are based on GDS' experience developing feasibility studies and implementation plans for many jurisdictions who have investigated and implemented CCAs. These Other Operating Costs are representative of other CCAs similar in size to a potential City CCA and include estimates of staffing and administrative costs, consultant costs, power supply costs, uncollectable charges, and TEP charges. In addition, it provides an estimate of start-up working capital and longer-term financial needs.

While power supply costs would make up the vast majority of costs associated with operating the CCA (power supply costs are roughly 95% total operating expenses for larger CCAs and around 90% for smaller CCAs based on our experience developing CCA budgets in California), there are additional cost components that must be considered in the proforma financial analysis. These additional non-power supply costs are summarized in Table 4-4 and then described below. Program start-up costs may include technical consulting to meet regulatory requirements for establishing a CCA and finalizing CCA budgets, working capital to procure initial power supplies and cover other operating costs while waiting (typically several months) for revenues to be collected from customers, and power supply credit management to satisfy lenders' security requirements for initial loans and working capital lines of credit (debt service). These non-power supply costs are representative of other CCAs roughly the size of a City CCA.

TABLE 4-4. SUMMARY OF ANNUAL NON-POWER SUPPLY COSTS ($1,000)

	2028
Data Management and Customer Service Call Center	$3,525
Power Management Consultant	$833
Schedule Coordinator/Dispatch	$486
Technical Consultants and Financial Services	$717
Marketing & Outreach	$347
Legal/Regulatory	$231
TEP Fees, Billing	$869
General & Administrative expenses	$5,484
Uncollectable	$2,302
Total O&M and A&G	**$14,794**
Debt Service	$12,242
PILOT(Payments in Lieu of Taxes)	$67,704
Total Non-Power Costs	**$94,740**

4.5.2.1 Outside Consultant Costs

Consultant costs would include outside assistance for legal and regulatory compliance, power supply management, scheduling coordinator, communication and marketing, data management, financial consulting, technical consulting, information technology, and implementation support.

CCA data management providers supply customer management system software and oversee customer enrollment and service, as well as payment processing, accounts receivable, and verification services. The cost of data management is charged on a per customer basis and has been estimated based on existing contracts for similarly sized CCAs. For this Study, the cost for data management is estimated at $1.00 per account per month.

The cost for other consulting support such as human resources, legal, customer service, marketing, technical support, accounting, information technology is estimated based on costs experienced by other CCAs. Consultant costs are increased by inflation every year. Table 4-5 summarizes the function of each key consultant role. Some roles are filled by one firm while other roles include services provided by more than one firm.

TABLE 4-5. SUMMARY OF CONSULTING SUPPORT SERVICES

Consultant Category	Key Functions
Power Management	– Short-term and long-term resource planning – Power procurement – Resource planning documents/Filings – Load Forecasts – Risk Management
Schedule Coordinator	– Daily/hourly balancing of loads and resources
Data Management and Customer Service Call Center	– Interface with TEP for data and billing – Staff customer service call center for CCA – Manage meter data
Financial Consulting	– Assist with banking services – Accounting/Audits
Technical Consultants	– Rate setting and rate making – Proforma management

Consultant Category	Key Functions
	– Information Technology, Website
Marketing and Outreach	– Develops and disseminates marketing materials and work products – Provides notices for opting out at program start
Legal/Regulatory	– Contracts, Board Meeting Support, Regulatory Support

4.5.2.2 Billing & Metering Costs

Under the proposed City CCA model, we assume TEP would provide billing and metering services to the City CCA. The estimated costs payable to TEP for services related to CCA start-up include costs associated with initiating service with TEP, processing of customer opt-out notices, customer enrollment, post enrollment opt-out processing, and billing fees. Billing fees are estimated at $0.27 per customer per month based on similar services provided by other IOUs. Annual costs for TEP billing and metering are estimated at $869,000.

4.5.2.3 Uncollectible Costs

As part of its operating costs, the CCA must account for customers that do not pay their electric bill. While TEP would attempt to collect funds, approximately 0.4% of revenues are estimated as uncollectible.[139] This cost is therefore included in the CCA operating costs, or expense budget. During the COVID-19 pandemic, uncollectible costs increased significantly across utilities; however, these costs have since returned to a more typical level.

4.5.2.4 Administrative & General Expenses

Administrative and general expenses include all other labor and expenses necessary to run the electric utility. Labor includes personnel in billing/customer service, accounting, information systems, and management. Office supplies and equipment includes the cost of purchasing (in the case of consumables such as paper and toner) or depreciation (in the case of depreciable assets such as computers, printers, and furniture). Facilities O&M includes the cost of operating and maintaining office space to house new employees. Miscellaneous costs include other A&G expenses not included in the categories listed above.

Staffing is a key component of operating a CCA. The City CCA would have discretion to distribute operational and administrative tasks between internal staff and external consultants in any combination. For this study, a moderate staffing scenario is modeled. This staff scenario relies on several dedicated full-time staff members and the use of technical consultants for support. As CCA programs mature, they typically add staff and services. This study provides a staffing level that is reasonable given the customer base; however, staffing levels could be adjusted in future years.

It is typical for a new CCA to initially rely on staff from member cities while hiring CCA positions in the first 2 years. Key staff members that would be hired prior to program launch include Chief Executive Officer, Chief Financial Officer, and Director of Power Supply. Once CCA launches, it is anticipated that staffing could increase to approximately 24 employees within the first two years of operation based on GDS' experience working with and observing other CCAs. These additional employees would cover functions such as key account services, customer outreach and programs, technical analysis, finance, marketing, and administrative staff.

Overhead needed to support the organization includes computers and other equipment, office furnishings, office space, utilities, and miscellaneous expenses. These expenses are estimated at $350,000/ year and escalated at inflation.

[139] Based on 2022 TEP cost of service study revenue requirement.

4.5.2.5 Customer Service

Customer service expenses include labor and expenses incurred to provide customer service such as billing, meter reading, customer information and advertising, records and collection. Customer service costs may vary by type of account based on usage profile or meter type. For example, a large industrial customer with a special contract for rates would require significantly more resources to bill compared with the average residential customer on a general rate schedule.

4.5.2.6 Payments in Lieu of Taxes

Similar to the City public power utility evaluation, PILOTs are assumed for the City CCA program. Since TEP applies tax rates to the total bill (delivery plus generation), PILOT must be included in the City CCA program expenses so that taxing authorities are held harmless. The PILOT includes payment for the Public Utility Tax, Franchise Fee, City Sales tax, State Sales tax, and regulatory charges. The total estimated PILOT is estimated at 13%. These expenses are included in the City CCA operating costs.

4.5.3 Non-Operating Expenses

Non-Operating Expenses include debt service and miscellaneous revenues. These are discussed below.

4.5.3.1 Debt Service

Debt service is assumed here to finance start-up and initial operations working capital, ongoing operating reserves, and financing security or collateral arrangements. It is assumed the CCA would obtain a line of credit for working capital equal to 3 months of O&M costs. Start-up costs for the program are estimated at $7.5 million. This value does not include the costs that might be incurred to fully define Arizona rules and regulations around CCA implementation or enabling legislation. This debt service is financed over 5 years at the tax-exempt rate.

4.5.4 Power Supply Credit Management

Prior to program launch in 2028, the City CCA will likely need to enter into multiple power supply contracts including long-term, medium and short term contracts as recommended by the Power Supply Management consultant. Credit support for power supply is assumed to cost $0.40/MWh to finance the contracts needed to serve the anticipated load. Credit support typically costs in the range of $0.30-$0.50/MWh. Other credit structures could also be used such as flat fee or percentage of the contract. These other options would be explored during the start-up phase. Annual costs are estimated at $3.8 million for the first 6 years. After year 6, the City CCA would likely have credit available to not need additional support.

4.6 STRANDED COSTS

City CCA customers would pay a stranded cost rate to TEP for their share of resource costs that cannot be recovered from the market. The cost stranding estimates developed in the City public power utility Section 3.10 also apply to the City CCA option. In the case of the City CCA, rather than the City CCA making payments direct to TEP to cover the stranded cost, City CCA customers would be charged for the stranded cost on their monthly power bills. This means that the City CCA must consider this stranded cost rate when setting its retail rates for power supply service. In order for the City CCA rate to be equal or lower than TEP's rate, the City CCA can charge up to the TEP power supply rate less the stranded cost rate.

Also as in the City public power utility study, non-bypassable charges for coal plant decommissioning are included in the stranded cost for City CCA customers. These were discussed in detail in Section 3.13.

4.7 TEP GENERATION RATE FORECAST

The City public power utility feasibility analysis forecasts TEP's power supply rate in Section 3.8.1; this was done separate from the transmission and distribution delivery portion of the rate. Based on TEP's historical costs and forecast revenue requirement developed for the preferred portfolio in its IRP, it's estimated that TEP's power supply rate will increase at an average of 3.4% annually.

4.8 PROFORMA RESULTS/RATE COMPARISON

Figure 4-3 compares the projected City CCA power supply costs with forecast TEP power supply costs. Based on the analysis, the City CCA costs are, on average, 18% lower than TEP's power supply rates. This 18% difference can be used to offer rate discounts or community programs such as energy efficiency. The City CCA would have the choice of determining the balance between the amount to lower customer rates and the amount of net operating revenues to realize.

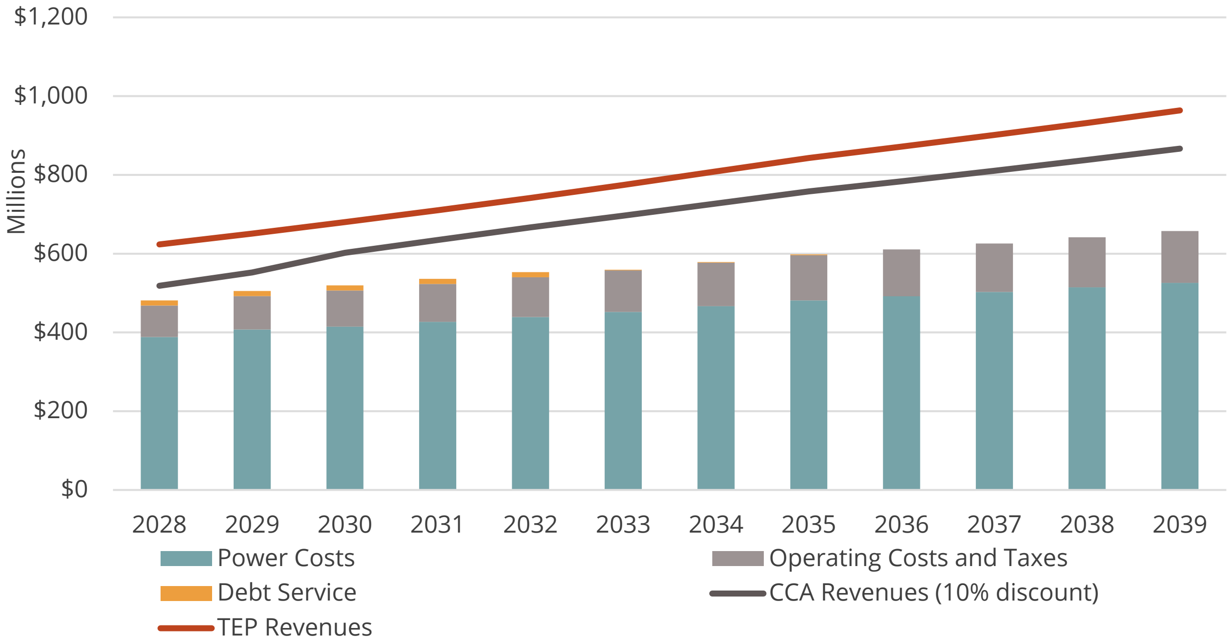

FIGURE 4-3. BASE CASE CCA FEASIBILITY RESULTS

4.9 SENSITIVITY

The base case and high case power supply costs are described in Section 3.10.1 of this report. A sensitivity analysis is performed with the power supply cost scenarios. Changes in power supply costs would typically affect TEP rates since the CCA and TEP would be transacting in the same market. So, if power supply costs are higher for the CCA, they will also be higher for TEP to the degree TEP relies on new resource prices and market transactions. As long as changes in power supply costs are reflected in the stranded rate, and the stranded cost rate is regularly updated, the impact from power market fluctuations is mitigated.

Figure 4-4 illustrates the impact of the high-power supply cost scenario. The CCA would reduce its rate discount temporarily to fully recover its operating costs; however, the program remains feasible.

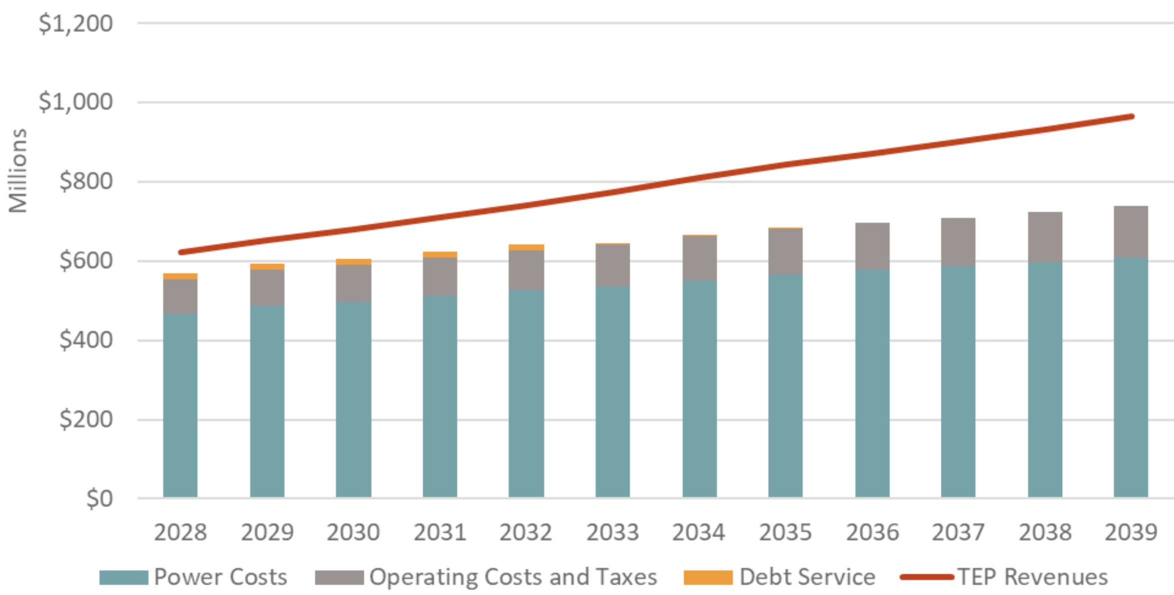

FIGURE 4-4. HIGH POWER COST CCA FEASIBILITY RESULTS

4.10 SUMMARY OF CCA PROGRAM UNCERTAINTIES

The CCA analysis is based on best practices from other states. If those best practices are not achieved within the enabling legislation and regulatory framework, the CCA program feasibility could be diminished. Table 4-6 summarizes some of the key assumptions and resulting impact on financial feasibility.

TABLE 4-6. KEY ASSUMPTIONS

Key Assumption	Impact
Power procurement through open markets	CCA may not be able to obtain competitive power supply.
Requirement of IOU to share electric load data to CCA prior to program start.	If the incumbent utility is not required to share electric load and customer information, forming a CCA would result in risks associated with unknown load profile and power supply costs. This would reduce the CCA program's ability to procure adequate and efficient power supply.
Generation cost stranding methodology includes all applicable market values and a requirement for transparency with the CCA	If the generation cost stranding methodology does not reflect all values associated with IOU portfolios, the stranded cost would be over-valued reducing feasibility for CCA programs and would harm consumers. If the stranded cost methodology is not transparent, the CCA will have difficulty in forecasting future changes leading to bill uncertainty for program participants.
Timing of IOU Rate Adjustments	Regular updates to IOU rates such as the stranded cost help CCA's maintain lower rates. If power supply costs increase and the increase is not reflected in the stranded cost, CCA customers would overpay for cost stranding resulting in inequitable allocation of costs between IOU and CCA customers.
Stranded Cost through Competitive Transition Charge (CTC) and cost Mitigation	Our analysis relies on a CTC charge billed monthly to CCA customers. There may be benefit of financing these charges over time through other mechanisms. Additionally, the analysis assumes that TEP would make efforts to reduce stranded investments and the process allows for review of such actions by CCA programs and the Commission.
Opt-Out Program Design	An opt-out program maximizes program participation and enables the CCA program to achieve economies of scale in its operating costs.

05 Societal Benefits of Reduced Emissions

Electricity generation is associated with several polluting emissions including carbon dioxide, nitrogen oxide, sulfur dioxide, and mercury. While TEP reports its emissions for each of these annually, this analysis attempts to quantify only the carbon dioxide component of TEP's resource portfolio compared with the public power options. Additionally, this analysis addresses only the carbon dioxide associated with power generation and does not consider lifetime emissions associated with construction and decommissioning.

For the public power utility and CCA options, the base case power supply portfolio estimates power costs for a portfolio that is 50% renewable in the first year of operation and 100% renewable by 2045. The carbon dioxide content of the portfolio is compared with the estimated TEP portfolio over the same time period.

5.1 TEP EMISSIONS ESTIMATES

TEP reported that its portfolio was 20% renewable in 2023.[140] GDS confirmed this information by calculating the renewable energy generation for 2023 as a share of total generation less wholesale sales from TEP's Electric Company ESG/Sustainability Quantitative Information.[141] Table 5-1 presents this calculation.

TABLE 5-1. TEP 2023 POWER CONTENT[A]

	2023 MWh	% of Retail Load
Coal	3,727,000	
Natural Gas	7,694,000	
Other (Market Purchases)	1,551,000	
Total Non-Renewable	12,972,000	
Wholesale Sales (FERC Form 1)	5,820,972	
Net Non-Renewable	**7,151,028**	**79%**
Solar	918,000	10%
Wind	1,031,000	11%
Total Renewable	**1,949,000**	**21%**
Total Retail Load	**9,100,028**	**100%**
(a) Includes owned generation and purchases.		

TEP states that its emissions for 2023 were 7,445,000 metric tons of carbon dioxide. TEP does not state whether these emissions include those associated with wholesale sales or if they are for native load only. To verify this value, GDS estimated emissions for TEP's retail load based on power plant emissions data and energy production reported in 2023. Emissions data for each of TEP's non-renewable resources is provided in Table 5-2. The average coal fired plant emissions factor is 1.03 MT/CO_2 per MWh. CO2 emissions from the gas-fired plants are higher at 1.29 MT CO_2/MWh.

[140] https://www.tep.com/our-energy-mix/

[141] TEP. Electric Company ESG/Sustainability Quantitative Information. June 2024. Available at: https://docs.tep.com/wp-content/uploads/TEP-EEI-ESG-2024.pdf

TABLE 5-2. TEP CO2 EMISSIONS RATE BY PLANT

Station	Unit No.	Physical Retirement Year	Fuel	Net Capacity MW	TEP Share %	TEP MW	Metric Ton (MT) CO_2/MWh[(a)]
Four Corners	4	2031	Coal	785	7%	55	0.96
Four Corners	5	2031	Coal	785	7%	55	0.96
Springerville	1	2027	Coal	387	100%	387	1.03
Springerville	2	2032	Coal	406	100%	406	1.03
Weighted Average							**1.03**
Sundt[(b)]	3	2032	Gas	104	100%	104	0.34
Sundt	4	2048	Gas	156	100%	156	0.34
Sundt CT[142]	1-2	2027	Gas	50	100%	50	0.34
Sundt Rice	6-10	2065	Gas	94	100%	94	0.34
Sundt Rice	1-5	2065	Gas	94	100%	94	0.34
North Loop CT	1-4	2046	Gas	96	100%	96	1.15
DeMoss Petrie CT	1	2046	Gas	75	100%	75	0.76
Luna Energy Fac	1	2066	Gas	555	33%	185	0.38
Gila River Power	3	2048	Gas	550	75%	413	2.01
Gila River Power	2	2048	Gas	550	100%	550	2.01
Weighted Average							**1.29**

(a) Sourced from eGRID2023: January 17, 2025.[143] Equal to short tons of CO_2 per MWh divided by net annual generation (MWh) converted to metric tons by plant.
(b) Data for all Sundt units based on Irvington Generating Station from eGRID2023.

In addition to owned generation, TEP also purchases power from the market. The CAISO market emissions factor is 0.428 metric tons CO_2/MWh. It is assumed that renewable energy (owned and purchased) produce no emissions. Table 5-3 shows the resulting emissions estimates.

TABLE 5-3. FORECAST TEP EMISSIONS

	City Only Retail Sales MWh	% GHG Free/Neutral	Emissions Rate MT CO2/MWh	Estimated MT CO2	Resource Changes
2028	5,256,036	46.4%	0.74	2,097,059	Retirement Springerville Unit 1
2029	5,308,596	51.4%	0.74	1,920,388	
2030	5,361,682	56.4%	0.74	1,739,973	
2031	5,415,299	40.0%	0.74	2,419,375	40% Renewable
2032	5,469,452	50.0%	0.74	2,036,307	Retirement Four Corners
2033	5,524,146	60.0%	0.63	1,395,420	Retirement Springerville Unit 2
2034	5,579,388	65.0%	0.63	1,233,203	60% Renewable
2035	5,635,182	70.0%	0.63	1,067,601	
2036	5,691,533	72.0%	0.63	1,006,392	

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[142] Combustion turbine

[143] U.S. Environmental Protection Agency. Emissions & Generation Resource Integrated Database (eGRID). Last update January 17, 2025. Available online: https://www.epa.gov/egrid

	City Only Retail Sales MWh	% GHG Free/Neutral	Emissions Rate MT CO2/MWh	Estimated MT CO2	Resource Changes
2037	5,748,449	74.0%	0.63	943,852	
2038	5,788,688	76.0%	0.63	877,347	
2039	5,829,209	78.0%	0.63	809,864	
2040	5,870,013	80.0%	0.63	741,394	
2041	5,911,103	82.0%	0.63	671,925	
2042	5,952,481	84.0%	0.63	601,448	
2043	5,994,148	86.0%	0.63	529,951	
2044	6,036,107	88.0%	0.63	457,423	
2045	6,078,360	90.0%	0.63	383,854	
2046	6,120,909	92.0%	0.63	309,233	
2047	6,163,755	94.0%	0.63	233,548	
2048	6,206,901	96.0%	0.63	156,789	
2049	6,250,350	98.0%	0.63	78,943	
2050	6,294,102	100.0%	0.63	-	

5.2 PUBLIC POWER EMISSIONS ESTIMATES

Emissions are estimated for the public power portfolio assuming the non-renewable portion of the portfolio is met with unspecified resources. Emissions for these unspecified resources are assumed to equal the emissions rate for the CAISO. The analysis does not forecast changes to this emission rate over time. However, the public utility could implement a policy that would require its portfolio to meet certain GHG requirements. So, rather than forecast the CAISO average emissions factors, the study assumes the public power entity would establish a ceiling for GHG emissions, and procurement of resources to meet power supply under the ceiling is acquired at the costs estimated by the market value of energy. Table 5-4 shows the resulting estimated emissions for the base case public power portfolio.

TABLE 5-4. PUBLIC POWER BASE CASE PORTFOLIO ESTIMATED EMISSIONS

	MWh	% GHG Free/Neutral	Emitting MWh	Emissions Rate MT CO2/MWh	Total Emissions MT CO2
2028	5,256,036	50%	2,628,018	0.428	1,124,792
2029	5,308,596	53%	2,488,404	0.428	1,065,037
2030	5,361,682	56%	2,345,736	0.428	1,003,975
2031	5,415,299	59%	2,199,965	0.428	941,585
2032	5,469,452	63%	2,051,044	0.428	877,847
2033	5,524,146	66%	1,898,925	0.428	812,740
2034	5,579,388	69%	1,743,559	0.428	746,243
2035	5,635,182	72%	1,584,895	0.428	678,335
2036	5,691,533	75%	1,422,883	0.428	608,994
2037	5,748,449	78%	1,257,473	0.428	538,199
2038	5,788,688	81%	1,085,379	0.428	464,542
2039	5,829,209	84%	910,814	0.428	389,828
2040	5,870,013	88%	733,752	0.428	314,046

	MWh	% GHG Free/Neutral	Emitting MWh	Emissions Rate MT CO2/MWh	Total Emissions MT CO2
2041	5,911,103	91%	554,166	0.428	237,183
2042	5,952,481	94%	372,030	0.428	159,229
2043	5,994,148	97%	187,317	0.428	80,172
2044	6,036,107	100%	0	0.428	0
2045	6,078,360	100%	0	0.428	0
2046	6,120,909	100%	0	0.428	0
2047	6,163,755	100%	0	0.428	0
2048	6,206,901	100%	0	0.428	0
2049	6,250,350	100%	0	0.428	0
2050	6,294,102	100%	0	0.428	0

5.3 SOCIAL COST OF CARBON

The Social Cost of Carbon (SCC) is the quantification of damages from climate change to society from a single ton of CO2. Damages include current and future impacts to the economy, health, society, and well-being.

The public power emissions reductions compared with TEP's preferred portfolio are valued at a range of SCC estimates. The first value is from the Environmental Protection Agency's most recent estimate for the SCC.[144] The EPA provides these estimates so that analysts reviewing the costs and benefits of certain decisions can include estimates of the social benefits of reducing greenhouse gas emissions. The latest EPA analysis includes recent advances in climate change and economic impacts as well as the 2017 recommendations from the National Academies of Science, Engineering and Medicine. Due to the timing of the study, the estimates do not include the economic impact recent natural disasters such as the 2024 hurricanes and 2025 California wildfires.

A 2024 University of California (UC Davis) study estimates the SCC at a cost twice the EPA value.[145] The study evaluated 20 years of SCC quantification studies. The authors analyzed the modeling structures within these studies and combined their findings with a survey conducted with study authors. A key results of this process shows that overwhelmingly, study authors indicated that the SCC is underestimated in their own analyses. Through statistical analysis and machine learning, the UC Davis study estimates the SCC at $283/metric ton ($2020).

Table 5-5 compares the SCC estimates adjusted to 2025 dollars using the U.S. City CPI.[146]

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[144] Environmental Protection Agency (EPA). *Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, "Standards of Performance for New Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" EPA Report on Social Cost of Greenhouse Gases: Incorporating Recent Scientific Advances.* Docket ID No. EPA-HQ-OAR-2021-0317, November 2023. Available at: https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf

[145] Moore, Frances C. et al. Synthesis of evidence yields high social cost of carbon due to structural model variation and uncertainties. Proceedings of the National Academy of Sciences of the United States of America. Volume 121. December 17, 2024. https://www.pnas.org/doi/10.1073/pnas.2410733121

[146] Bureau of Labor Statistics. Consumer Price Index all Urban Consumers. Seasonally adjusted. https://data.bls.gov/dataViewer/view/timeseries/CUSR0000SA0;jsessionid=B082819E317A4A0861A4EE818610BD0D

TABLE 5-5. SCC ESTIMATES $/METRIC TON CO_2

	EPA $2020 (a)	EPA $2025	UC Davis $2025
2020	$190	$234	$349
2030	$230	$284	$423
2040	$270	$333	$496
2050	$310	$382	$570
(a) Discount Rate:2%			

5.4 SOCIAL BENEFITS OF CARBON REDUCTION

The difference in total emissions between TEP's portfolio and the public power portfolio is valued at the two estimates of SCC: EPA and the UC Davis study. The resulting net present value is estimated between $2.7 and $4 billion over the 23-year period 2028-2050.

TABLE 5-6. SOCIAL BENEFITS OF CARBON REDUCTION, BASE CASE PUBLIC POWER PORTFOLIO

	TEP Portfolio	Public Power	GHG Reductions	EPA Value $/MT	EPA Value $Millions	UC Davis Value $/MT	UC Davis Value $Millions
2028	2,097,059	1,124,792	972,267	$234	$228	$349	$339
2029	1,920,388	1,065,037	855,350	$239	$205	$356	$305
2030	1,739,973	1,003,975	735,998	$244	$180	$364	$268
2031	2,419,375	941,585	1,477,790	$249	$368	$371	$548
2032	2,036,307	877,847	1,158,460	$254	$294	$378	$438
2033	1,395,420	812,740	582,680	$259	$151	$386	$225
2034	1,233,203	746,243	486,960	$264	$129	$393	$191
2035	1,067,601	678,335	389,266	$269	$105	$401	$156
2036	1,006,392	608,994	397,398	$274	$109	$408	$162
2037	943,852	538,199	405,654	$279	$113	$415	$168
2038	877,347	464,542	412,805	$284	$117	$423	$174
2039	809,864	389,828	420,036	$289	$121	$430	$181
2040	741,394	314,046	427,348	$294	$125	$437	$187
2041	671,925	237,183	434,742	$298	$130	$445	$193
2042	601,448	159,229	442,219	$303	$134	$452	$200
2043	529,951	80,172	449,779	$308	$139	$459	$207
2044	457,423	0	457,423	$313	$143	$467	$213
2045	383,854	0	383,854	$318	$122	$474	$182
2046	309,233	0	309,233	$323	$100	$481	$149
2047	233,548	0	233,548	$328	$77	$489	$114
2048	156,789	0	156,789	$333	$52	$496	$78
2049	78,943	0	78,943	$338	$27	$503	$40
2050	0	0	0	$343	$0	$511	$0
NPV at 2%					$2,661		$3,963

If evaluating the Accelerated renewable portfolio, which achieves 100% renewable by 2035, the net present value in benefit increases to $3.8 to $5.6 billion over the same period.

06 Virtual Power Purchase Agreement / Solar Service Agreement

The City of Tucson ("the City") is currently implementing and considering enhancements of its strategy to satisfy the electricity needs of its municipal operations, while supporting long-range sustainable development, cost stability, and climate goals. Leveraging Arizona's strong solar potential, the City has adopted an approach that utilizes SSAs and is considering the utilization of VPPAs specifically to address the balance of its municipal electric load. These two methods along with TEP's Green Energy Tariff serve to assist the City in meeting its goals while accepting that there is not an established REC market in Arizona.

SSAs allow the City to install behind-the-meter solar energy systems on municipal rooftops, landfills, and other publicly owned properties. These systems directly offset a portion of the City's electricity use and require no upfront capital investment. With 72 SSA systems installed and operating today, these facilities produce approximately 30,000 megawatt-hours (MWh) annually or roughly 15% of the City's total municipal electricity consumption. SSAs offer a predictable, fixed energy rate to the City and visible proof of its commitment to clean energy.

To offset other municipal energy needs that cannot be met via on-site solar, the City is considering VPPAs. The VPPAs would enable the City to support renewable energy development somewhere else on the grid while securing RECs. These RECs, given the City's current standards and approach, count toward the City's sustainability reporting and emissions reduction targets.

To reach greater municipal renewable energy goals, the City can expand the number of SSA sites and contracts, pursue VPPAs, install battery storage onsite at SSA locations, and examine participation in TEP's Green Energy Tariff (Rider-23). This utility program allows large energy users to purchase energy from new renewable projects, with varying levels of additionality and customization.

6.1 GOALS & LIMITATIONS

Arizona has one of the largest shares of sun among the most solar-rich states in America[147], despite being ranked 6th by percent of solar to state load[148]. With thousands of megawatts of installed solar capacity and ongoing technological advancement, the state continues to demonstrate strong potential for scalable and cost-effective renewable energy deployment. These conditions provide a favorable foundation for Arizona communities—including the City of Tucson—to pursue a range of clean energy strategies.

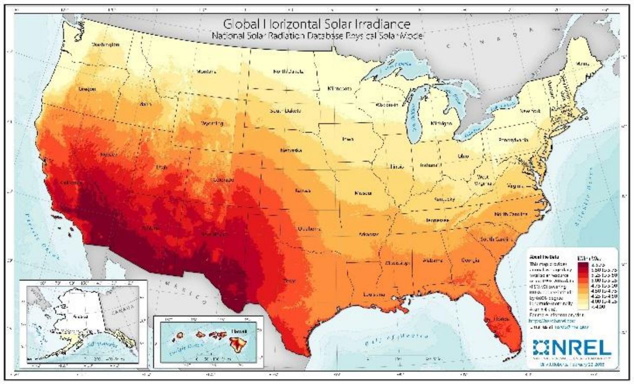

FIGURE 6-1. NREL GLOBAL HORIZONTAL SOLAR IRRADIANCE MODEL

As part of its broader sustainability and energy objectives, the City of Tucson established objectives aimed at significantly increasing the proportion of renewable or carbon-free electricity powering municipal operations. Meeting these goals requires a portfolio approach that incorporates multiple procurement mechanisms and adapts to practical, economic, and operational constraints.

[147] https://www.nrel.gov/docs/libraries/gis/high-res-images/solar-annual-ghi-2018-usa-scale-01.jpg?sfvrsn=135d48b6_1
[148] https://emp.lbl.gov/utility-scale-solar/

SSAs and VPPAs can and could play an important role in the City's current and future renewable energy planning. While different in structure and application, both SSAs and VPPAs can facilitate access to large amounts of clean energy.

- SSAs enable the City to install solar energy systems on public facilities with no upfront capital costs. These behind-the-meter installations offset on-site energy use and offer long-term budget predictability through fixed or indexed pricing.
- VPPAs will allow the City to financially support renewable energy projects located elsewhere on the grid. While the electricity may not be physically delivered to City facilities, the City will receive RECs that can be used to track and report renewable energy use.

While SSAs and VPPAs offer flexibility and scalability, they also come with considerations that affect how progress toward energy goals is measured.

One such consideration is additionality—the extent to which a procurement leads to the development of new renewable energy projects. The degree of additionality varies by project and procurement structure and may be important to evaluate the environmental impact of an initiative.

Another factor is the non-dispatchable nature of solar energy, which only generates electricity during daylight hours and fluctuates with weather conditions. This can create a mismatch between the timing of renewable generation and the City's actual electricity consumption. Tools such as energy storage, demand management, or procurement diversification may be used to address this challenge, depending on program design and priorities.

These realities underscore that progress toward renewable energy goals can be measured in different ways—including total annual renewable energy procured, percentage of energy matched in real time, or the contribution to new renewable development. Each of these dimensions may inform how success is defined and how resources such as SSAs and VPPAs are used in combination. Furthermore, the City goals and definitions of success may continue to evolve with its stakeholders' interests.

The sections that follow provide a closer look at how SSAs are currently being used by the City of Tucson, and how both SSAs and VPPAs may continue to support the City's evolving clean energy strategy.

6.2 WHAT IS A SOLAR SERVICE AGREEMENT?

A SSA is a contractual arrangement that enables an organization to benefit from on-site solar energy generation without owning or operating the system. Under an SSA, a third-party solar developer designs, installs, owns, and maintains the solar photovoltaic (PV) system on the customer's property. In return, the customer agrees to purchase the electricity generated by the system at a predetermined rate through a power purchase agreement (PPA) that spans 15 to 28 years. Residential PPAs, a common subset of SSAs, follow a similar model but are specifically tailored to individual homeowners. However, this report focuses exclusively on larger-scale SSA applications intended to serve municipal operations for the City of Tucson.

This model offers several advantages:

- No upfront capital investment for the customer
- Predictable long-term energy costs
- Professional system maintenance and performance risk shifted to the provider
- City receives the RECs and retains the green characteristics of the energy that is produced.

6.2.1 Current Utilization

SSAs have become a widely adopted renewable energy procurement mechanism across a range of sectors:

- ***Commercial and Industrial (C&I):*** Businesses use SSAs to reduce operating expenses and support sustainability objectives without the administrative burden of system ownership.
- ***Government and Municipal Entities:*** Public-sector organizations (including cities, counties, and agencies) leverage SSAs to meet renewable energy mandates and climate goals while preserving capital budgets for other priorities.
- ***Educational Institutions:*** K–12 schools and universities have embraced SSAs to integrate solar into their campuses, reduce utility costs, and reinforce environmental education.

6.2.2 Future Utilization Trends

The use of SSAs is expected to grow nationwide, supported by several converging trends:

- ***Corporate Sustainability Commitments:*** As more organizations set renewable energy and carbon reduction targets, SSAs offer a turnkey solution for clean energy procurement.
- ***Expansion into Residential Markets:*** SSAs are increasingly entering the residential market.
- ***Integration with Energy Storage:*** Advancements in battery storage technology are expanding SSA offerings to include storage components, enabling customers to increase self-consumption, reduce peak demand charges, and improve resilience.

6.2.3 Technical Considerations: Interconnection and Grid Integration

SSAs involve more than just contractual and financial arrangements—they also require thoughtful grid and infrastructure planning:

- ***Utility Interconnection Compliance:*** All SSA systems must comply with the local utility's interconnection policies, which govern how distributed generation systems are safely connected to the grid.
- ***Grid Impacts and Infrastructure Needs:*** When solar systems export energy to the grid, potential system impacts must be assessed. In many cases, grid infrastructure—such as transformers or distribution circuits—must be upgraded to accommodate the two-way flow of electricity and ensure reliability and safety.

These technical requirements are especially relevant for larger or clustered installations and can influence project timelines, costs, and feasibility.

6.3 WHAT IS A VIRTUAL POWER PURCHASE AGREEMENT?

A Virtual Power Purchase Agreement is a financial contract used to finance the construction of a renewable energy facility between the renewable energy developer and a buyer—typically a large organization. As a result of such contracts, renewable energy generation is assured, while providing the buyer with environmental benefits. The key difference between these agreements and traditional PPAs is that, with VPPA, there is no physical delivery to the buyer.

Under this arrangement, the buyer agrees to purchase the financial output of a renewable energy project at a fixed price, while the electricity generated from the project is sold into the wholesale market. The parties settle the difference between the fixed VPPA price and the actual market price:

- If the market price exceeds the contract price, the difference goes to the buyer.
- If the market price falls below the contract price, the difference needs to be paid by the buyer to the developer.

As a result, the buyer typically receives the RECs associated with the energy produced. The buyer may use those credits toward its sustainability targets or carbon reduction claims.

6.3.1 Current Utilization

VPPAs have become a common component of corporate renewable energy strategies, particularly among large organizations with sustainability agendas:

- *Corporate Leadership:* Due to a variety of reasons, VPPAs are utilized by some of the biggest multinational companies to secure renewable energy credits, without needing to locate near a renewable project or alter their physical electricity supply.
- *Renewable Project Financing:* VPPAs help renewable energy developers secure financing by providing long-term revenue certainty. This has supported the development of large-scale wind and solar farms across the United States.

6.3.2 Future Utilization Trends

VPPA adoption is expected to continue growing as clean energy goals and environmental accountability expand across sectors:

- *Broader Corporate Participation:* More companies—including mid-sized firms—are entering the VPPA market, some via aggregated VPPAs, sharing access to large renewable projects.
- *Grid Decarbonization Catalyst:* VPPAs are recognized as a meaningful tool for enabling grid-wide decarbonization. They can help accelerate the deployment of large-scale renewable resources, including emerging sectors like offshore wind and utility-scale solar-plus-storage.
- *Geographic Expansion:* While VPPAs have historically been concentrated in markets like Texas and the Midwest, growth is expected in new regions—driven by evolving state-level policies, Renewable Portfolio Standards (RPS), and carbon reduction goals.

6.3.3 Technical Considerations: No Physical Delivery Required

One of the key features of a VPPA is that it requires **no physical interconnection or transmission path** to the buyer's facilities. The agreement is entirely financial in nature and includes the following components:

1. *Energy Sale to the Grid:* The renewable project sells electricity into the wholesale market at the prevailing price.
2. *Contract-for-Difference (CfD):* The buyer and developer settle the financial difference between the VPPA price and the market price.
3. *Renewable Energy Credits (RECs):* The buyer receives RECs to claim the environmental attributes of the renewable energy generated.

This structure makes VPPAs highly flexible and scalable, allowing buyers to support new renewable energy development regardless of their geographic location or utility constraints.

6.3.4 Risk Considerations: Market Exposure and Financial Volatility

While VPPAs offer important environmental and strategic benefits, they also introduce exposure to wholesale electricity market volatility, which can directly impact the financial performance of the agreement:

- *Market Downside Risk:* If market prices fall below the fixed VPPA price, the buyer is obligated to pay the developer the difference. In prolonged periods of low market prices, this could lead to sustained net payments by the buyer, increasing the overall cost of participation.
- *Hedge Value vs. Liability:* Although VPPAs are often used as a hedge against rising energy prices, they are not guaranteed to produce savings. They function more like financial derivatives and must be accounted for in terms of risk-adjusted value—not just headline pricing.

- ☐ ***Accounting and Budgeting Complexity:*** The fluctuating financial flows from VPPAs can complicate budgeting and accounting. Municipalities must evaluate the potential for year-over-year variability and may require internal or third-party financial expertise to monitor performance and assess ongoing risk.
- ☐ ***Regulatory and Market Design Factors:*** Changes in market structure, congestion pricing, or regulatory policy can also influence project economics over time, particularly in multi-state agreements or merchant market regions.

In light of these factors, VPPAs should be carefully structured and managed to balance the environmental benefits of renewable energy procurement with the financial realities of market risk exposure. Strong contract design, financial modeling, and internal oversight are essential to realizing the full value of a VPPA while maintaining budgetary stability.

6.4 STRENGTHS AND CHALLENGES OF SSA AND VPPA STRATEGIES

Together, SSAs and VPPAs enable a diversified, scalable, and flexible energy strategy. The City can layer multiple mechanisms (e.g., SSA + storage + VPPA) to balance costs, maximize renewable share, and adapt to site-specific or policy limitations. High level cost impacts and comparison between SSAs, VPPAs and the TEP Green Tariff can be found further in this report.

6.4.1 Strengths

TABLE 6-1. STRENGTHS OF SSAS AND VPPAS

Strengths	SSAs	VPPAs
No Capital Outlay	No upfront investment by the City, making them accessible and budget-friendly.	No upfront investment by the City, making them accessible and budget-friendly.
Stability of Costs in the Long-Term	Assure fixed or predictably increasing rates.	Provide a hedge against future market volatility.
Scalable Portfolio	Target on-site generation.	Provide access to larger scale, off-scale renewable energy.
Environmental Impact	Directly reduce grid dependency and emissions at City facilities.	Support the development of new renewable capacity and deliver RECs to document progress toward goals.
Operational Simplicity	Maintenance and system performance are handled by third-party providers, reducing City staff burden	More complex, operate independently of City facilities.

6.4.2 Challenges

- ☐ ***Site Limitations for SSAs:*** Most of the prime City-owned property has already been utilized with the 72 current SSA installations. Potential future SSA expansion may be limited by space, structural constraints, or inefficiencies in use with facility load profiles.
- ☐ ***Grid Export Limitations:*** SSA excess energy compensation amounts are lower because they are calculated using avoided cost rates, thus calling for careful system sizing to ensure cost effectiveness of the energy production.
- ☐ ***Market Risk in VPPAs:*** VPPAs expose the City to wholesale market price fluctuations, which may result in variable financial outcomes over time.
- ☐ ***Complexity of VPPA Contracts:*** Legal, accounting, and energy market expertise are necessary to ensure correct execution and management of VPPA.

- *Lack of Local Visibility:* With some VPPAs, projects may be out of state, thus reducing the opportunity for local economic development or visible renewable deployment.
- *Integration of Storage:* Storage batteries added to the SSA sites can contribute to the performance and resilience but will increase capital costs and require more complex evaluation.

By understanding and actively managing these strengths and limitations, the City of Tucson can continue refining its procurement strategy to meet municipal renewable energy goals with clarity, efficiency, and long-term impact.

6.5 POLICY AND REGULATORY CONSIDERATIONS

The legal and regulatory environment in Arizona provides a generally supportive framework for municipalities like the City of Tucson to pursue renewable energy goals through SSAs and VPPAs. However, successful implementation requires careful attention to state laws, federal incentives, utility relationships, and contractual best practices.

6.5.1 Solar Service Agreements – Legal and Market Considerations

- *Third-Party Ownership Permissibility:* Arizona law allows third-party ownership models, which are the foundation of SSA structures. This enables solar developers to install, own, and operate systems on public properties, while the City purchases the electricity under a long-term agreement.
- *Contractual Flexibility:* Arizona recognizes various structures for SSAs, including power purchase agreements (PPAs) and capital leases. These forms may affect project financing, tax treatment, and eligibility for federal incentives.
- *Utility Coordination:* SSA deployment requires compliance with utility interconnection standards and coordination regarding grid access, net metering, or infrastructure upgrades. In some cases, utility-specific rules or capacity limitations may affect site selection or system sizing. Successful SSA implementation depends on alignment with TEP interconnection policies, distribution infrastructure capabilities, and rate structures.

6.5.2 Virtual Power Purchase Agreements – Legal and Operational Considerations

- *Permissibility and Structure:* VPPAs are permissible in Arizona and are structured as financial contracts-for-difference between a buyer and a renewable energy developer. These contracts typically involve the transfer of RECs to the buyer and are not subject to physical energy delivery requirements.
- *Cross-State Procurement:* VPPAs can be used to support projects located both inside and outside Arizona, giving the City access to cost-effective renewable generation beyond local grid constraints. However, regulatory compliance must be maintained across jurisdictions, particularly for REC trading and energy market participation.
- *Contract Complexity and Risk Management:* VPPAs involve sophisticated legal and financial terms, including exposure to wholesale market price volatility. These agreements require expert review to address risks related to energy pricing, project underperformance, and changing regulatory landscapes.

The City of Tucson operates within a generally favorable legal environment for both SSAs and VPPAs. However, realizing their full value requires thoughtful navigation of tax policy, contract structures, utility coordination, and market risks. With proper planning and oversight, these tools can be effectively leveraged to support long-term renewable energy goals while maintaining financial responsibility and regulatory compliance.

6.6 SOLAR SERVICE AGREEMENTS FOR THE CITY OF TUCSON

6.6.1 Feasibility

Arizona's exceptional solar resource makes the state a highly favorable environment for solar energy development. The City of Tucson is well-positioned to capitalize on this advantage through the continued deployment of SSAs.

- *Solar Resource Potential:* With some of the highest solar irradiance levels in the country[149], Tucson is ideally suited for solar power generation. SSAs allow the City to utilize this natural resource by installing solar systems on municipal rooftops, public facilities, parking canopies, transit infrastructure, and city-owned land.
- *Capital-Free Model:* SSAs offer a particularly accessible model for municipalities, as they do not require upfront capital investment. Instead, the solar developer finances, installs, owns, and maintains the system, while the City purchases the energy at an agreed-upon rate—typically fixed or escalated in a predictable manner.
- *Long-Term Performance:* Standard SSA contract terms range from **15 to 25 years**, aligning with the useful life of the solar equipment. Arizona's stable and sunny climate ensures consistent energy generation over time, enhancing the long-term value of these agreements.

6.6.2 Cost-Effectiveness

SSAs provide the City with a financially viable pathway to clean energy, offering both immediate and long-term economic benefits.

- *Energy Savings:* SSA pricing is often below the prevailing utility retail rate, especially when factoring in rising fossil fuel costs and utility rate escalation. Over the life of the contracts, the City may realize substantial savings compared to traditional grid energy purchases. Savings do not always occur and are largely dependent upon scale and specifics of the project. The City's current SSA portfolio has an average system size of approximately 300 kW. According to the City's analysis for Fiscal Year 2024, the City's SSA contracts produced close to 30,000,000 kWh which yielded a savings of $861,000. Each kWh produced created a savings of almost 3 cents.
- *Rate Stability:* Fixed or predictable energy rates under SSAs help protect the City from utility rate volatility. This budget stability is a significant advantage for municipal energy planning and long-term financial forecasting.
- *Tax Benefit Pass-Through:* Although municipalities cannot directly claim the federal Tax Credits (when applicable) or other tax incentives, solar developers can. These benefits are typically factored into SSA pricing, resulting in more competitive rates for the City.
- *Reduced Operational Burden:* Under the SSA structure, the third-party provider is responsible for all maintenance, monitoring, and system performance, minimizing the City's operational workload and associated costs.

6.6.3 Challenges and Constraints

While SSAs are highly beneficial, there are several considerations that must be managed to optimize outcomes.

- *Site Suitability:* The availability of suitable rooftops or land can limit the scale of SSA deployment. Structural, zoning, shading, and load considerations must be assessed on a site-by-site basis.
- *System Sizing and Energy Value:* Because SSAs are typically structured around behind-the-meter consumption, maximizing on-site usage is critical. Energy exported to the grid is compensated at the avoided

[149] https://www.nrel.gov/docs/libraries/gis/high-res-images/solar-annual-ghi-2018-usa-scale-01.jpg?sfvrsn=135d48b6_1

cost rate by TEP, which is generally significantly lower than the effective SSA rate. Oversized systems that routinely export excess energy may reduce project economics.

- ***Long-Term Contractual Commitment:*** While long-term agreements provide stability, they also present risk if future energy prices decline or new technologies significantly change market conditions. Contract terms should include flexibility provisions where feasible.
- ***Operations/Ownership Issues:*** Clear contractual language should address potential liens on property, allowable access rights for the owner/operator to maintain equipment, performance guarantees ensuring expected energy production, and the responsibilities related to damage repair or equipment failure.

6.6.4 Current Deployment and Impact

The City of Tucson has been diligent and successful in identifying, siting, and implementing solar systems under SSA structures.

- The City currently operates nearly 75 SSA systems, distributed across a wide range of municipal properties.
- These systems generate almost 30,000 megawatt-hours (MWh) annually, accounting for roughly 15% of the City’s total municipal electricity consumption.
- Most installations are right-sized to align closely with on-site energy use, enhancing their economic value and minimizing excess exports to the grid.
- ***System Size & Distribution:*** The average nameplate capacity of each SSA system is approximately 300 kilowatts DC (kWdc). This indicates a focus on small to mid-scale, distributed solar installations suited for large rooftops, parking structures, and other municipal properties. There are systems as small as 9.9 kW and as large as a 8.2MW system that will be completed this year in Avra Valley.
- ***Pricing:*** The weighted average SSA rate across these sites is approximately 11.7 cents per kilowatt-hour (kWh).
- ***Performance:*** The SSA portfolio has an average capacity factor just below 20%. While this may appear modest, it is consistent with expectations for small, decentralized solar systems operating in Arizona, where system orientation, shading, and equipment type can vary across sites.
- ***Contract Terms:*** The majority of the City’s SSA agreements have contract durations ranging from 20 to 28 years, aligning with typical solar asset lifespans and allowing the City to lock in long-term clean energy at stable rates.

6.7 VIRTUAL POWER PURCHASE AGREEMENTS FOR THE CITY OF TUCSON

6.7.1 Feasibility

Virtual Power Purchase Agreements provide a flexible and scalable mechanism for municipalities to support renewable energy development and procure the environmental benefits of clean power—without needing direct access to or ownership of energy infrastructure.

- ***Applicability to Public Sector Goals:*** VPPAs are increasingly utilized by both corporate and public sector entities seeking to advance renewable energy or carbon neutrality targets. Through a VPPA, the City can contract for the output of a renewable energy project—often wind or solar—located anywhere in the U.S. and claim the Renewable Energy Certificates (RECs) associated with that generation.
- ***Geographic Flexibility:*** Unlike on-site solar, VPPAs do not require physical proximity between the energy user and the generation source. This flexibility enables the City to access projects in regions with strong renewable resources or lower development costs, potentially improving economic value.
- ***Strategic Complement to SSAs:*** VPPAs can function as a strategic complement to SSAs. While SSAs provide local, behind-the-meter generation, VPPAs offer access to large-scale, utility-scale clean energy—enabling the City to address broader portions of its municipal energy footprint.

6.7.2 Cost-Effectiveness

VPPAs are structured to provide financial predictability and cost-effective carbon reduction, though they come with unique market and contractual considerations.

- *Energy Price Hedge:* VPPAs typically involve a fixed contract price for energy, while the renewable project sells its electricity into the wholesale market. This structure allows the City to hedge against rising market prices and can produce financial upside if the market price exceeds the VPPA price.
- *Cost-Efficient Carbon Accounting:* The purchase of RECs through a VPPA provides a streamlined and measurable way for the City to offset a portion of its carbon emissions. This makes VPPAs a practical tool for carbon accounting and emissions reduction without requiring capital investment in infrastructure.
- *Developer Incentives Passed Through:* Like SSAs, VPPA developers can benefit from federal and state tax incentives and production-based incentives. These savings are typically reflected in the VPPA pricing, offering better value to the City.

6.7.3 Challenges and Constraints

Despite their flexibility and scale, VPPAs require careful evaluation and risk management to ensure effective execution.

- *Market Exposure:* Because VPPAs are typically tied to wholesale electricity markets, they carry exposure to market price volatility. If market prices fall below the contract price, the City may be required to pay the difference, which can reduce or eliminate cost savings. This risk can be managed through contract design and price floor mechanisms.
- *Contractual Complexity:* VPPAs are legally and financially complex agreements that involve contract-for-difference structures, REC management, and energy market settlement processes. Legal and financial expertise is essential to protect the City's interests and ensure favorable terms.
- *Project Location and Local Impact:* VPPAs often support projects outside the City or state, which may limit local economic benefits such as job creation or visibility of clean energy investments. While still valid from a carbon reduction standpoint, this can be a consideration in public-facing sustainability strategies.

6.7.4 Current Deployment and Impact

The City of Tucson has not executed any VPPAs but is in the process of considering these agreements as part of its renewable energy portfolio strategy.

VPPAs offer a compelling option for the City of Tucson to procure renewable energy at scale while supporting new clean energy infrastructure. Their geographic flexibility, cost-effectiveness for carbon offsetting, and compatibility with large-scale energy goals make them an important tool in the City's clean energy toolkit. However, they require thoughtful risk assessment and contract management to fully realize their potential benefits.

6.8 COMMUNITY BENEFITS OF COMBINED STRATEGY

The City of Tucson should use a multiprong approach to achieving its municipal renewable energy and carbon reduction goals. Beyond meeting internal sustainability goals, the combined use of SSAs and VPPAs delivers ancillary benefits that align with Tucson's broader economic and resilience priorities:

- *Economic Development:* SSA deployment can stimulate investment in local infrastructure, attract solar developers, and create installation and maintenance jobs within the city. At the same time, VPPAs can drive the growth of large-scale renewable projects in other parts of Arizona, supporting rural economic development and advancing the state's clean energy industry.

- *Energy Resilience and Grid Reliability:* SSA installations paired with battery energy storage can improve resilience at critical city facilities, providing backup power during outages and helping to manage peak demand. As the City explores storage-enabled solar sites, opportunities for collaboration with TEP could further support load shaping and even enable microgrid development for essential services.

- ***Cost and Risk Diversification:*** The combination of fixed-rate SSAs and market-linked VPPAs helps balance financial exposure, providing both budget certainty and the potential for hedging against future energy price increases.

A coordinated SSA and VPPA strategy enables the City of Tucson to meet its renewable energy targets in a practical and scalable manner. SSAs serve as the foundation for visible, local solar deployment, while VPPAs provide access to cost-effective, utility-scale renewable resources beyond the city's footprint. Together, these tools support not only municipal climate goals, but also broader objectives related to economic development, energy resilience, and responsible public stewardship.

6.9 EXISTING SSA CONTRACT AND GOAL ACHIEVEMENT ASSESSMENT

While the City is well on its way toward ambitious renewable energy targets, additional procurement—through expanded SSA deployments, enhanced VPPA participation, and other green energy strategies—will be necessary to close the gap over time.

6.10 INCREMENTAL STORAGE FEASIBILITY & ASSESSMENT

Solar service agreements are inherently constrained by the availability of suitable host sites where on-site solar generation can directly offset a facility's energy consumption. These limitations stem from factors such as rooftop or land area, solar access, structural capacity, and load characteristics. Because SSAs rely on behind-the-meter generation, the volume of energy that can be offset is capped by the extent to which on-site generation aligns with the site's load profile.

The integration of battery energy storage systems (BESS) can enhance the value of an SSA by reshaping a facility's load to better coincide with solar production. Storage enables time-shifting of excess solar energy for use during peak demand periods or when solar generation is low, thereby increasing the proportion of on-site generation that is self-consumed rather than exported to the grid. This effectively expands the amount of energy that can be offset behind the meter.

However, the addition of storage significantly increases capital and operating costs. As a result, the levelized cost of energy (LCOE) for each kilowatt-hour offset tends to rise when storage is incorporated. This trade-off requires a careful cost-benefit analysis, balancing higher per-kWh costs against potential gains in energy savings, demand charge reduction, or resiliency benefits.

To maximize the impact and efficiency of future SSA deployments—particularly those that incorporate storage—it may be beneficial for the City to explore collaborative opportunities with TEP. Working in partnership with the utility could help identify viable models for solar-plus-storage systems that support load shaping, grid stability, and even community resilience goals. In particular, storage-enabled SSAs could lay the groundwork for localized microgrids, capable of serving critical infrastructure during outages or grid disruptions. These integrated approaches may offer enhanced value not just for municipal operations, but also for broader community energy reliability and sustainability.

Virtual Power Purchase Agreements, in contrast, are not constrained by physical site limitations and offer virtually unlimited scale for renewable energy procurement. VPPAs allow a buyer to contract for the output of a renewable energy project—often located remotely—and receive the associated RECs, even if the physical electrons are delivered elsewhere on the grid.

However, the lack of geographic or grid-proximate sourcing may reduce the perceived environmental and community impact benefits. In other words, while VPPAs support renewable development broadly, they do not always result in new local generation or direct emissions reductions within the buyer’s service area. This can be a concern for stakeholders seeking place-based or additionality-oriented climate solutions.

Furthermore, because VPPAs are purely financial instruments—involving contract-for-difference structures tied to wholesale market prices—they do not interface with the buyer’s physical energy usage. Consequently, the incorporation of energy storage has no functional or financial relevance within a VPPA. Storage would not alter the buyer’s financial exposure or increase the volume of credited renewable energy and thus provides no value in this context.

6.11 TEP GREEN TARIFF

6.11.1 Overview of TEP's Green Energy Tariff (Rider-23)

TEP provides customers the option to directly support renewable energy through its Green Tariff program, known formally as Rider-23. The program allows customers to voluntarily purchase renewable electricity generated from new renewable energy resources, enabling participants to meet sustainability goals and support clean energy development.

6.11.2 Eligibility & Availability

This program is available to individually metered customers within TEP's service territory, primarily targeting larger electricity users. Eligible customers include:

- Large General Service, Large Power Service, and 138kV Service Classes
- Small General Service, Medium General Service, and Lighting customers, if their combined peak load exceeds 1 megawatt (MW) or their annual consumption surpasses 5,000 megawatt-hours (MWh).

6.11.3 Renewable Energy Procurement Options

TEP offers three distinct options for renewable energy procurement under Rider-23:

OPTION A:

- Purchase renewable energy from new TEP resources operational after January 1, 2021.
- Commit to at least one year; pricing is established at the initiation of the contract.

OPTION B:

- Procure renewable energy from specific new TEP projects located in designated areas.
- Pricing, subscription volumes, and contract terms are customized and mutually agreed upon, subject to approval by the Arizona Corporation Commission (ACC).

OPTION C:

- Directly support renewable resources not currently planned by TEP or expedite previously planned renewable projects.
- Bear all incremental project-related costs and commit to fixed renewable energy volumes over an agreed contract period.
- All contracts require ACC approval.

6.11.4 Pricing Structure

Participants pay an additional premium (Green Power Charge) on top of their standard electricity rate. This charge reflects actual renewable resource procurement costs, typically ranging between $0.001 to $0.02 per kilowatt-hour (kWh). An administrative fee may also apply, depending on the terms of the specific agreement.

6.11.5 Management and Ownership of Renewable Energy Credits

Renewable Energy Credits, which represent the environmental attributes associated with renewable electricity generation, are managed by TEP but generally transferred to participating customers. Ownership details for RECs are clearly defined within each individual customer agreement. Customers can use these RECs to achieve sustainability goals or demonstrate compliance with renewable energy targets.

6.11.6 Contract Requirements

Customers interested in participating must enter into a formal contractual agreement with TEP prior to receiving service under Rider-23. Each contract outlines:

- Customer accounts included in the green energy program.
- Volume and type of renewable energy procured.
- Pricing terms and administrative fees.
- Contract duration and specific terms.
- Management and ownership of RECs.

6.11.7 Participation for Large Customers (e.g., City of Tucson)

Large customers, including municipalities like the City of Tucson, are eligible to participate in TEP's Green Tariff program, provided they meet the criteria of energy consumption levels outlined above. Participation would involve entering a customized contractual agreement with TEP, choosing from the available renewable energy procurement options (A, B, or C), and obtaining necessary approvals from the ACC, particularly under Options B and C.

6.12 SSA, VPPA & TEP GREEN TARIFF COMPARISON

6.12.1 Comparison of Solutions

The following table provides a comparison of the three different means (described previously) of procuring renewable energy for the city's utilization:

TABLE 6-2. COMPARISON OF SOLUTIONS

Factor	TEP Green Energy Tariff	SSA	VPPA
Cost per kWh	$0.003-$0.02 above retail	11.7 cents	Variable (market)
Upfront Capital	None	None	None
Risk Exposure	Low	Low	Moderate-High
REC Ownership	Yes	Yes	Yes
Additionality	Depends on Option	Yes	Potentially
Location of Generation	Off-site (TEP territory)	On-site (City facilities)	Off-site (any U.S. grid)
Flexibility & Scale	Medium	Limited	High
Long-Term Cost Certainty	Medium	High	High

07 Microgrid

A microgrid is a localized and integrated energy system which operates independently or alongside the traditional utility grid to provide resilient, reliable, and sustainable power. Microgrids include renewable energy sources (e.g., solar PV), energy storage systems, backup generation, and advanced control technologies to ensure continuous operation during outages and optimize overall energy usage.

The City of Tucson's goals for microgrid deployment include:

1. ***Enhancing community resilience,***
2. ***Ensuring power reliability to critical facilities,***
3. ***Increasing renewable energy use, and***
4. ***Safeguarding vulnerable populations during extreme heat events.***

Collaboration with TEP is essential in order to meet interconnection regulations and to effectively and economically utilize the microgrid capacity and energy generation investment. TEP follows Arizona Corporation Commission (ACC) regulations on interconnection policies and how to integrate them into broader resource planning with other utilities and open ways of mutual benefit concerning grid reliability. Active cooperation between Tucson and TEP defines the optimal locations of installation sites and cost structures for microgrid implementation.

From a technical and design standpoint, microgrids in Tucson should leverage available solar resources and can be complemented by energy storage systems sized to meet specific load requirements and duration of outages. Advanced controllers manage the power flow, enabling seamless transitions between grid-connected and islanded operations. These systems are engineered for scalability, resilience serviced during extreme weather events, and efficient energy management.

The economic justification and feasibility of microgrids involve comprehensive cost-benefit analyses. Microgrid power supply is typically more costly in terms of average energy prices. However, improvements related to public safety, resilience, reliability, and environmental sustainability can justify those incremental costs. Strategic alignment with TEP's resource planning can reduce overall microgrid costs substantially, enhancing economic viability. Microgrid controls can reduce operating costs by minimizing energy required from generators and maximizing efficiency.

Specific cases in Tucson include critical infrastructure such as hospitals, emergency response centers, community cooling centers (e.g., Donna R. Liggins Center), and neighborhoods vulnerable to heat-related impacts. In this assessment, two example microgrid applications are considered for serving Tucson's energy resilience goals:

- ***Community Cooling Zone Microgrid:*** A smaller-scale system located at a city-owned recreation or community center, designed to provide safe refuge for vulnerable populations during high-heat events and utility outages. Emphasis is placed on low capital cost, moderate energy demand, and critical public safety.
- ***Community Critical Load Microgrid:*** A larger, more complex microgrid intended to support essential services at facilities such as hospitals. This system requires higher generation and storage capacity, more advanced control systems, and robust integration with utility infrastructure, but provides critical uninterrupted service to life-saving infrastructure.

Potential locations in Tucson were narrowed down according to critical infrastructure, community vulnerabilities, and environmental threats. Preliminary size and cost analyses (described further in this report) indicate that community-scale microgrids (for example, cooling centers) would cost approximately $0.9M, while hospital-scale (or similarly sized shape and load) microgrids require around $8.4M. Strategic integration with TEP's infrastructure planning can significantly reduce these costs.

A structured, practical step-by-step guide created for Tucson indicates the importance of goal setting, site selection, TEP coordination, technical design, economic evaluation, leveraging successful precedents, and thorough implementation and monitoring to ensure optimal outcomes for microgrid deployments.

7.1 MICROGRID DEFINITION

7.1.1 What A Microgrid is and is Not in The Context of an Electric Utility

The Institute of Electrical and Electronics Engineers (IEEE) defines a microgrid as "a localized energy system designed to operate either in parallel with the utility grid or independently during disruptions." It integrates multiple distributed energy resources (DERs), such as renewable energy generation (e.g., solar panels, wind turbines), battery storage systems, and conventional generation sources (e.g., diesel generators)—alongside advanced control technologies.

7.1.2 Characteristics of a Microgrid

- ***Energy Resilience:*** Microgrids can "island" themselves from the main grid during power outages or disruptions, thus providing uninterrupted energy supply to critical facilities including hospitals, emergency response centers, military bases, and industrial plants.
- ***Sustainability:*** By incorporating renewable resources, microgrids considerably lessen fossil fuel dependency, thus lowering greenhouse gases and supporting environmental sustainability initiatives.
- ***Cost Management:*** Microgrids optimize energy usage by managing peak demand and improving efficiencies, thereby reducing energy costs for consumers and potentially postponing expensive upgrades to the traditional grid infrastructure.
- ***Operational Flexibility:*** Facilities with microgrids can locally generate and manage their energy, reducing reliance on centralized utilities and enhancing operational autonomy. Microgrids are generally modular in nature and include protections such as generation trip settings, under-frequency load shedding, fault selectivity, and energy injection.
- ***Multiple Use-Cases:*** These systems are adaptable to diverse target environments: ranging from rural communities with few options for access to the grid to densely populated urban areas requiring congestion relief.

Microgrids have historically been successfully deployed in environments such as college campuses, hospitals, and large industrial complexes. A prominent example is Princeton University during Superstorm Sandy in 2012, where their microgrid successfully maintained continuous operations despite widespread power loss in the region.

7.1.3 What a Microgrid is Not

- ***Not Just a Standby Generator or Energy Storage System:*** Unlike a simple backup diesel generator or energy storage system, a microgrid includes multiple integrated power resources and sophisticated control systems to actively match electricity generation with real-time consumption needs.
- ***Not Only Solar Power Generation:*** Solar alone cannot function as a microgrid because they cannot manage production based on immediate demand. Solar installations require additional resources like batteries or generators, combined with advanced telemetry and controls to manage energy output reliably.
- ***Not a Replacement for the Main Grid:*** Microgrids are supplementary to the main utility grid. Their main function is to enhance reliability, resiliency, and reduce congestion, whereas they usually operate in parallel with, and secondary to, the larger grid whenever both systems are operational.

7.1.4 Key Benefits to Utilities and Consumers

- Enhanced reliability during emergencies or outages.
- Reduced carbon footprint due to increased efficiency and renewable energy integration.
- Economic sharing of energy generation assets between multiple connected facilities.
- Enhanced grid stability by managing congestion and peak demand.

According to recent reports, over 2,400 microgrids operate in the United States, underscoring their growing role in modern energy systems and utility infrastructure planning.

7.2 GOALS OF MICROGRID IN THE CITY

The City of Tucson would greatly benefit from microgrid technology due to its hot climate, increasing population, and sustainability goals. The use of microgrids fits in well with Tucson's other priorities of establishing cooling hubs, increasing reliability and resiliency of power supply, and inviting renewable resources into the mix.

- ***Cooling Hubs and Community Resilience:*** Microgrids can provide energy to several of these critical cooling hubs during periods of extreme heat to save lives for the most vulnerable. With ample, reliable power supply, such hubs guarantee that residents have access to safe, climate-controlled spaces even during prolonged outages of the main electrical grid. Essentially, a microgrid with solar generation and battery storage can supply clean and uninterrupted power to these centers, in turn, greatly improving community safety and well-being.
- ***Reliability and Grid Resilience:*** Like many cities in the southwestern United States, Tucson faces risks associated with extreme weather events, including heatwaves and monsoon storms. These can disrupt traditional grid infrastructure. Hence, microgrids enhance resilience by providing localized power generation capable of operating independently (islanding) during grid disturbances. The operational continuity of facilities such as emergency response centers, hospitals, and public shelters will, hence, greatly mitigate the vulnerability of the city during any crisis.
- ***Upscaling of Green Generation Resources:*** Microgrids can maximize the utilization of Tucson's abundant solar resource. By integrating photovoltaic panels with advanced battery storage systems, microgrids can efficiently store solar energy for use during peak demand periods, reducing reliance on fossil fuels and lowering greenhouse gas emissions. This supports Tucson's long-term sustainability and climate goals.
- ***Economic Development and Infrastructure Savings:*** Microgrids are stimulating economic development and reducing infrastructure costs in various cities in the Southwest, such as Phoenix and Las Vegas. Microgrids give credibility to cities to attract technology-focused businesses seeking reliable and sustainable energy. They also alleviate strain on existing grid infrastructure, deferring expensive upgrades and reducing maintenance expenses.
- ***Improving Public Health and Safety:*** Microgrids can improve air quality and public health by decreasing reliance on diesel backup generators. Diesel backup generators are commonly used during emergencies but contribute significantly to local air pollution. Cleaner energy from microgrids can reduce respiratory and cardiovascular health risks in the community.
- ***Coordination with Tucson Electric Power:*** When microgrids are deployed in front of retail electric meters, their successful integration and operation require close collaboration with TEP. Coordination with TEP ensures microgrid compatibility with the larger utility infrastructure, adherence to regulatory requirements, and alignment with system operational procedures. Collaborative planning and operations optimize microgrid benefits for all stakeholders, enhancing overall grid stability and reliability while advancing Tucson's broader energy and sustainability initiatives. In 2023, TEP invested $103M in renewable energy projects, $254M in

transmission and distribution system upgrades, and $140M in new or upgraded generating resources. TEP ranks in the top quartile of all electric utilities across the country for service reliability and resiliency.[150] Coordination and collaboration with TEP to effectively deploy microgrids is a key to success.

7.3 TUCSON ELECTRIC POWER POLICIES AND COLLABORATION ON MICROGRID DEPLOYMENT

7.3.1 Overview of Policies and Regulations

TEP operates under stringent Arizona state regulations, specifically outlined in Title 14, Chapter 2, Article 26 of the Arizona Administrative Code and enforced by the ACC. These rules deal with the interconnection of Distributed Energy Resources (DER) facilities from application to operation. TEP provides detailed technical requirements in their approved Interconnection Manual for DER Projects, along with guidance in Section 700 of TEP's Electric Service Requirements. Moreover, interconnection directly with TEP's transmission system is regulated under TEP's Open Access Transmission Tariff (OATT), filed with the FERC.

7.3.2 Customer-Installed Generation Requirements

All customers intending to install generation assets "behind-the-meter" (distributed generation or storage systems installed on the customer side of the utility's metering infrastructure) are subject to adherence to TEP's interconnection policies. This is the industry-wide requirement charged to assure safety, reliability, and the least obtrusive integration into the grid. Customers deploying behind-the-meter power resources essentially do so for the express purpose of achieving resiliency during outages and increasing their deployment and consumption of renewable energy resources.

Neighborhood microgrid concepts that aim to interconnect shared renewable energy, battery storage, or generation assets across multiple homes or retail consumers—without direct collaboration with TEP—are largely constrained by standard utility interconnection rules. These policies are designed to ensure system reliability and safety, particularly during grid outages or abnormal operating conditions. For such a configuration to be viable, TEP would need to formally interconnect the resources and install specialized switching and protection equipment to allow the neighborhood to operate independently (island) from the main grid when necessary. As discussed elsewhere in this report, the cost and complexity of the required storage, backup generation, and utility-grade interconnection equipment would likely render the concept economically impractical for typical residential settings when compared to the existing level of service and reliability provided by TEP.

In the circumstance whereby all of the generation and storage equipment is located behind the TEP meter, the integration of solar, storage and other generation technologies can be deployed technically and can serve to provide resiliency, however, the incremental cost of this additional reliability is usually a burden that the average residential consumer would not deem economically practical.

7.3.3 Reliability Tracking and Customer Collaboration

Regulators require TEP to maintain detailed records related to grid reliability and service interruptions. In the spirit of transparency, TEP makes its reliability data available to its customers, including the City of Tucson, to help identify potential sites suitable for microgrid installations. By targeting areas of potential vulnerability or specific reliability challenges, TEP can enable its stakeholders to strategically target locations that could benefit from microgrids to enhance resiliency and customer satisfaction.

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[150] https://www.tep.com/reliable/#:~:text=even%20more%20reliable.-,Reliability,committed%20to%20doing%20even%20better .

7.3.4 Working Relationship with the City of Tucson

TEP has been fostering conversations with the City of Tucson, emphasizing their commitment to collaborating on microgrid opportunities and distributed generation technologies. Their collaborative effort on projects such as the Donna Liggens Center in TEP's willingness to identify and realize community-driven energy solutions. Such projects integrate seamlessly with larger goals for generation and grid enhancement, thereby contributing substantially to the city's overall resiliency and public safety objectives.

7.3.5 Opportunities for Resiliency Hubs

TEP supports the establishment of "Resiliency Hubs" within the city. Resiliency Hubs would be strategic facilities that can operate independently during grid outages through localized microgrid control systems. These hubs would provide essential services, including shelter and cooling centers, ensuring public safety during emergencies.

7.3.6 Need for Generation/Storage Capacity Value

In order for a Tucson-based microgrid to be economically viable at scale, it likely needs to be utilized as a capacity resource by Tucson Electric Power. Without participation in TEP's resource planning and grid operations, the microgrid would be treated solely as a backup or islanded system—providing limited value and requiring customers to bear the full cost of storage, controls, and generation infrastructure. However, if TEP integrates the microgrid into its capacity portfolio, the utility can defer or offset investments in centralized infrastructure, reduce peak demand, and enhance grid resilience—allowing a portion of those avoided costs to be shared with the microgrid operator or customers. This dual-use structure—where the microgrid serves both local reliability and broader system needs—is essential to unlocking cost efficiencies and delivering a financially feasible deployment model.

7.3.7 Conclusion

TEP is open and proactive in both microgrid and DER projects, considering them complementary to its broader reliability and sustainability strategies. Because of its regulatory requirements, customer cooperation, and real-life experience, TEP is ideally positioned as a prime partner for the City of Tucson's initiatives to enhance local energy resiliency, environmental sustainability, and community welfare.

7.4 TECHNICAL CHARACTERISTICS FOR TUCSON MICROGRIDS

7.4.1 Technology Considerations

Deploying microgrids in Tucson requires careful integration of components tailored to the city's hot climate, abundant solar resource, and community resilience needs. The complexity and technical design of a microgrid will vary significantly depending on its intended use. A community cooling center microgrid is typically smaller in scale, with limited critical loads to be served. It generally involves simpler control systems and modest interconnection requirements. In contrast, a hospital or other community critical load microgrid demands continuous, high-reliability power, larger generation and storage capacities, advanced system controls, redundant backup capabilities, and stringent regulatory compliance. These systems are more integrated and complex to ensure seamless operation during extended grid outages. Below are key considerations for microgrids within Tucson:

7.4.1.1 Generation and Storage Systems

- ***Solar Photovoltaic (PV) Power Generation:*** Tucson's abundant sunlight makes solar PV highly attractive for microgrid generation, offering cost-effective and environmentally sustainable power. Ideal for locations with significant rooftop space or open land.
- ***Energy Storage:*** Essential for Tucson microgrids to store solar energy during peak sunlight hours and discharge during evening or high-demand periods. Lithium-ion batteries, valued for their efficiency, scalability, fast

response time, and reliability, are particularly suited to Tucson's technical requirements, though careful thermal management is necessary to mitigate performance degradation due to heat. Emerging Long Duration Energy Storage (LDES) technologies may become more suitable for deployments for resiliency applications as costs rapidly decrease. However, current storage systems, especially lithium-ion, are typically limited to durations of 2–6 hours and will only supply power when charged; continuous or repeated operation depends entirely on the system's ability to be recharged, usually by available solar generation.

- ***Combined Heat and Power (CHP) Systems:*** CHP can be attractive for sites with simultaneous heating/cooling and power needs, such as hospitals or large commercial facilities. It is less suitable for purely residential areas where thermal demand is limited.
- ***Thermal Generators:*** These can serve as reliable backup during prolonged outages or when renewable generation is insufficient. However, their use should be limited and well-managed due to cost, noise, fuel storage requirements, and emissions concerns. Diesel-based microgrids are by far the most common throughout the world, given the relatively low upfront capital cost of the generator and its widespread availability.
- ***Wind Turbines:*** Generally less attractive in Tucson due to limited and inconsistent wind resource, though potentially viable in select locations with higher wind exposure.

7.4.1.2 Advanced Control and Management Systems

- ***Microgrid Controller:*** Critical for managing the intermittent nature of solar generation, battery storage, and backup generation, ensuring seamless operation between grid-connected and islanded modes during Tucson's frequent heat waves and monsoon-related outages.
- ***Energy Management Software:*** Incorporate predictive analytics tailored to Tucson's climate and consumption patterns, enhancing energy efficiency, managing peak loads, and maintaining reliability during extreme weather events.

7.4.1.3 Interconnection and Grid Integration

- ***Interconnection Equipment:*** Design systems compatible with TEP guidelines and regulatory standards, facilitating smooth and safe transitions between isolated and connected operations.
- ***Protection Systems:*** Utilize robust protective relays and coordination schemes appropriate for Tucson's environmental conditions to ensure safety during grid disturbances or equipment failures.

7.4.1.4 Load Characterization and Management

- ***Smart Meters and Sensors:*** Essential for detailed load analysis in Tucson's high-demand cooling scenarios, facilitating accurate and efficient energy management.
- ***Demand Response and Efficiency:*** Implement demand response programs specifically targeting peak cooling loads, promoting efficiency, and reducing operational stress on system components.

7.4.1.5 Resilience and Reliability Planning

- ***Redundancy and Backup Generation:*** Plan for redundancy in critical system components (especially energy storage and controllers) to guarantee continuous operations during extreme weather events.
- ***System Robustness:*** Engineer microgrid infrastructure to withstand Tucson's intense heat, solar radiation, and occasional severe storms, ensuring durability and longevity.

7.4.1.6 Scalability and Future-Proofing

- ***Modular and Flexible Architecture:*** Adopt designs allowing incremental expansions and seamless integration of future technologies, maintaining adaptability to Tucson's evolving energy landscape.

- ***Standards and Interoperability:*** Align system components with recognized industry standards to ensure smooth interoperability and facilitate future upgrades or integrations.

7.4.2 How Components Work Together to Create Value

Microgrids combine these components into an integrated system that can operate independently or collaboratively with the main grid. Solar panels generate renewable energy, reducing environmental impact, with excess energy stored in batteries for later use during lower production or higher demand.

Advanced control systems constantly balance energy supply and consumption, seamlessly switching between renewable generation, stored energy, and backup generation. During power outages or grid instability, the microgrid controller automatically isolates ("islands") the microgrid, ensuring continuous, stable energy for critical facilities and communities.

This coordinated approach delivers several benefits:

- ***Enhanced Reliability and Resiliency:*** Continuous, stable energy even during grid disruptions.
- ***Environmental Sustainability:*** Reduced carbon footprint and fossil fuel dependency through renewable integration.
- ***Cost Efficiency:*** Optimized energy use reduces peak demand charges.
- ***Energy Independence:*** Greater control over energy generation and reduced reliance on external providers.

Together, these components empower Tucson communities and businesses, fostering a sustainable, resilient, and efficient energy future.

7.5 FEASIBILITY, JUSTIFICATION AND ECONOMICS OF MICROGRIDS AND ANALYTICAL APPROACH

When evaluating the feasibility of microgrid deployments, the following considerations are required for effective planning and successful implementation:

- ***Need and Priority:*** Identifying and clearly defining the critical need for a microgrid is paramount. Facilities providing essential services—such as healthcare centers, emergency response facilities, cooling hubs for vulnerable populations, and critical municipal infrastructure—should receive highest priority, especially where grid reliability is a known concern, or outages pose significant risks to public health and safety. In other cases where there are industrial processes that require high degrees of reliability and resiliency, microgrids could be a solution that can and should be funded by the industrial need.
- ***Site Feasibility:*** Site-specific evaluations assess the physical space available for microgrid components (e.g., solar panels, energy storage units, generators) and the suitability of these sites based on environmental, community, and regulatory factors. Detailed feasibility studies address permitting requirements, environmental impact assessments, zoning regulations, community acceptance, and potential barriers that could affect project timelines or overall viability.
- ***Cost and Economic Integration:*** Cost analysis, incorporating both upfront capital expenditure and ongoing O&M expenses, is critical. Special consideration should be given to integration with utility resource planning, as well as interconnection requirements and potential infrastructure upgrade costs. Collaboration with the local utility, such as TEP, can significantly offset project costs through strategic alignment with broader utility reliability and renewable energy objectives. The idea is that the generation capacity associated with the microgrid could be utilized to support the grid throughout the year, rather than just the seldom case where the microgrid must function when service is interrupted

Addressing these factors in prioritized order—clearly identified need, robust site feasibility assessment, and comprehensive cost analysis—ensures that microgrid projects effectively enhance community resilience, energy reliability, and sustainability goals.

The economic justification for deploying a microgrid typically relies on a comprehensive analysis of costs, benefits, and risk mitigation factors. Organizations and communities considering microgrid installations conduct detailed evaluations to ensure financial feasibility and identify value propositions clearly.

7.5.1 Key Factors in Economic Justification

1. **Cost Savings from Energy Efficiency and Demand Reduction**
   - Microgrids manage peak energy usage, potentially reducing demand charges and overall energy expenses.
   - Integration of Combined Heat and Power (CHP) or renewable resources can lower long-term operational costs.
2. **Reliability and Resiliency Benefits:**
   - Critical facilities (e.g., hospitals, emergency response centers, data centers) significantly benefit by maintaining operations during grid outages, preventing costly disruptions.
   - Avoiding downtime reduces potential financial losses, often measured through the Value of Lost Load (Vol) methodology.
3. **Avoided Infrastructure and Grid Upgrade Costs:**
   - Microgrids can defer or eliminate costly upgrades to existing grid infrastructure by locally managing energy loads and production.
4. **Environmental and Sustainability Value:**
   - Reducing greenhouse gas emissions and increasing renewable energy use can qualify for financial incentives, rebates, and improved public perception.

7.5.2 Impact on Overall Average Cost of Power

In most cases, deploying a microgrid for enhanced resiliency or increased use of distributed, smaller-scale generation—whether renewable or conventional—results in a higher average cost of power. This occurs because a microgrid, being a localized and smaller-scale system, generally loses economies of scale inherent in larger centralized systems. However, there are unique circumstances where the deployment of a microgrid could actually lower the average cost of power, particularly in areas where the existing or newly required infrastructure is exceptionally expensive to deploy, upgrade or maintain.

The incremental or premium cost associated with microgrids is often justified by enhanced safety, reliability, and the provision of essential community services. Distributed generation assets located strategically near microgrid deployments can create valuable synergies, underscoring the importance of collaboration between energy consumers and local utilities to identify economically and operationally beneficial scenarios.

7.5.3 Analytical Methods for Justification

- ☐ ***Cost-Benefit Analysis (CBA):*** A detailed comparison of upfront investment and ongoing operational costs against quantified monetary benefits, such as energy savings, incentives, and avoided outage costs.
- ☐ ***Avoided Outage Costs:*** The overall economics for a microgrid incorporate certain non-energy (non-quantifiable) benefits to the community in a critical event, such as having climate-controlled shelter, lighting, and basic food preparatory functionality, or continued communications/ operations of emergency medical services. These benefits, called avoided outage costs, can be aggregated into a single benefit dollar amount per kWh that the user places on the unmet site load during grid outages, or the losses that the site would

experience if the load were not met. The value of lost load (VoLL) is used to determine the avoided outage costs by multiplying VoLL ($/kWh) with the average number of hours that the critical load can be met by the energy system, then multiplying by the mean critical load.

- ***Return on Investment (ROI) and Payback Period:*** Calculations to determine the period required to recover initial investments based on projected savings and operational efficiencies.
- ***Lifecycle Cost Analysis (LCA):*** Assessment of total ownership costs, including initial investment, operation, maintenance, and disposal or replacement over the microgrid's operational lifespan.
- ***Sensitivity Analysis:*** Evaluation of financial performance under various scenarios, including fuel price fluctuations, regulatory changes, and variations in load or renewable energy availability, to assess project robustness.
- ***Financial Modeling and Simulation:*** Utilizing advanced simulation tools to model microgrid performance under different scenarios, quantifying reliability and resilience benefits clearly.

7.5.4 Funding Sources and Grants for Microgrid Projects

Microgrid projects can leverage various funding sources, including federal, state, and local grants, alongside industry and private-sector contributions. Prominent federal programs include funding from the U.S. Department of Energy (DOE), specifically through its Office of Electricity and Grid Modernization initiatives, which regularly provide substantial grants supporting innovative energy resiliency and renewable integration projects.

State-level support often comes via Public Utility Commissions or energy departments, offering incentives for projects aligning with regional energy goals, resilience improvements, or renewable energy integration. In Arizona, for example, incentives and financing opportunities might be coordinated through the Arizona Commerce Authority or similar entities.

Industry partnerships and private-sector investments significantly augment funding. Utilities have begun to collaborate with end users or customers through cost-sharing arrangements when microgrids align with their IRPs, as microgrids can enhance overall grid resilience and capacity. Private companies and technology vendors may also contribute financially or through equipment discounts as part of technology demonstrations or corporate sustainability initiatives.

Additionally, public-private partnerships (PPPs) increasingly fund microgrid developments, combining resources from municipalities, utilities, private investors, and technology providers, thus distributing risks and enhancing project feasibility.

7.5.5 Conclusion

By carefully analyzing these factors, stakeholders ensure informed decisions regarding microgrid investments, emphasizing both immediate cost implications and long-term value derived from increased reliability, sustainability, and operational resilience.

7.6 MICROGRID SPECIFIC USE CASES, EXAMPLES

Microgrids offer tailored energy solutions that enhance reliability, sustainability, and resilience for urban areas like Tucson. By integrating localized energy generation with advanced control systems, microgrids can operate independently or in conjunction with the main power grid, providing flexible and secure energy management.

7.6.1 Specific Use Cases for Microgrids in Tucson

1. **Community Resilience Centers:**
   - ***Cooling Centers:*** Given Tucson's high temperatures, designated cooling centers provide refuge during extreme heat events. Equipping these centers with microgrids ensures they remain functional during grid failures, offering residents a safe haven.

- ***Community Centers:*** Facilities like the Donna R. Liggins Recreation Center serve as gathering points during emergencies. A microgrid can ensure these centers provide essential services when the main grid is compromised.

2. **Critical Infrastructure Support:**
   - ***Healthcare Facilities:*** Hospitals and emergency medical centers require uninterrupted power to ensure patient safety and continuous operations. Implementing microgrids can safeguard these facilities against grid outages.
   - ***Emergency Response Centers:*** Police stations, fire departments, and emergency coordination hubs benefit from microgrids by maintaining operational readiness during power disruptions.

3. **Educational and Research Institutions:**
   - ***University Campuses:*** The University of Arizona's Biosphere 2 facility has been identified as a potential site for an energy-water microgrid test bed. Such a microgrid could serve both research purposes and demonstrate practical applications of integrated energy and water management systems.

4. **Industrial Applications:**
   - ***Manufacturing and Industrial Facilities:*** Industrial operations in Tucson require consistent, high-quality power to maintain productivity and prevent costly downtime. Microgrids can deliver reliable power, stabilize voltage fluctuations, and integrate renewable resources, enhancing energy efficiency and operational continuity in critical industrial sectors.

7.6.2 Donna R. Liggins Recreation Center Microgrid

The Donna R. Liggins Recreation Center, located in Tucson's Sugar Hill neighborhood, has been identified as a prime candidate for microgrid implementation. The center functions as a community hub, providing recreational activities and serving as a cooling center during extreme heat events. Equipping the center with a microgrid would ensure continuous operation during power outages, thereby enhancing community resilience. The Tucson Mayor and City Council have applied for funding to support this microgrid project, reflecting the city's commitment to bolstering infrastructure against climate-related challenges.

7.6.3 Regional Examples of Successful Microgrid Deployments

These projects[151] exemplify the diverse applications and capacities of microgrids in enhancing energy resilience and sustainability across various sectors.

TABLE 7-1. REGIONAL EXAMPLES OF SUCCESSFUL MICROGRID DEPLOYMENT

Project Name	City	Op Year	Latest Install Year	Primary Application	Generation Capacity (MW)	Storage Capacity (kW)	Technologies
Aligned Data Center	Phoenix	2017	2017	Data Center	63	0	Diesel
Arizona State University Microgrid	Tempe	2016	2019	College / University	40.49	0	CHP, Diesel, Solar

[151] https://doe.icfwebservices.com/state/microgrid/AZ

Project Name	City	Op Year	Latest Install Year	Primary Application	Generation Capacity (MW)	Storage Capacity (kW)	Technologies
Caterpillar Tucson Proving Ground Microgrid, near Green Valley	Green Valley	2016	2016	Research Facility	1.73	500	Diesel, Solar, Storage
Grand Canyon West Microgrid	Peach Springs	2014	2023	City / Community	3.135	750	Diesel, Solar, Storage
Marine Corps Air Station Yuma	Yuma	2016	2016	Military	25	0	Diesel

By strategically deploying microgrids in these contexts, Tucson can enhance the reliability of critical services, promote sustainable energy practices, and improve overall community resilience against environmental and infrastructural challenges.

7.7 POTENTIAL MICROGRID CENTERS AND LOCATIONS

One of the first steps in planning the implementation of a microgrid is identifying the facility's function during community emergencies, key characteristics, and constraints. Considerations include the size of the building or facility itself, the size of the surrounding land and property, the layout and configuration of the facility, available space for solar arrays such as rooftops, parking lots, or other open land, available space for energy storage, existing electrical equipment, energy efficiency, and the use case of microgrid. Each facility is unique and will serve a different purpose during an emergency outage. The microgrid should be designed to provide sufficient uninterrupted power supply to critical electric loads. These factors affect the design and sizing of the power resources, and they will vary by facility to meet specific needs. Enhancing the resilience of critical infrastructure in Tucson through microgrids and renewable energy integration is vital for ensuring continuous service delivery, especially during environmental challenges. Below is a non-comprehensive list of key facilities, their addresses, and the services they provide where by a Microgrid could create value:

TABLE 7-2. POTENTIAL MICROGRID CENTERS

Facility Name	Address	Service Provision
Banner – University Medical Center Tucson	1625 N Campbell Ave, Tucson, AZ 85724	A 649-bed teaching hospital offering comprehensive medical services, including a Level I trauma center.
Tucson International Airport	7250 S Tucson Blvd, Tucson, AZ 85756	Major airport providing commercial and cargo air services, serving as a critical transportation hub.
Ryan Airfield	9698 W Tucson-Ajo Hwy, Tucson, AZ 85735	General aviation airport supporting civilian aviation activities and emergency response operations.
Arizona State Prison Complex – Tucson	10000 S Wilmot Road, Tucson, AZ 85734	Correctional facility housing various security levels, requiring continuous power for security and operations.
Tucson Federal Building	300 W Congress Street, Tucson, AZ 85701	Hosts federal agencies such as the IRS, Department of Labor, and others, essential for government operations.

Facility Name	Address	Service Provision
U.S. Customs and Border Protection – Tucson Sector Headquarters	2430 S Swan Road, Tucson, AZ 85711	Oversees border security operations across the Tucson sector.
Evo A. DeConcini Federal Courthouse	405 W Congress Street, Tucson, AZ 85701	Federal courthouse handling legal proceedings and housing various federal agencies.
James A. Walsh U.S. Courthouse	38 S Scott Avenue, Tucson, AZ 85701	Historic courthouse facilitating federal judicial activities.
Tucson Electric Power Headquarters	88 E Broadway Blvd, Tucson, AZ 85701	Provides electric utility services to Tucson and surrounding areas.
Pima County Sheriff's Department Headquarters	1750 East Benson Hwy, Tucson, AZ 85714	Main law enforcement agency for Pima County, ensuring public safety.
Tucson Fire Department Station 1	300 S Fire Central Place, Tucson, AZ 85701	Primary fire station providing emergency response services.
Tucson Water Department	310 W Alameda Street, Tucson, AZ 85701	Manages water supply and quality for Tucson residents.
Pima County Health Department	3950 S Country Club Rd, Suite 100, Tucson, AZ 85714	Provides public health services, including clinics and health programs.
University of Arizona Police Department	1852 E First Street, Tucson, AZ 85719	Ensures safety and security on the University of Arizona campus.
Tucson Medical Center	5301 East Grant Road, Tucson, AZ 85712	Non-profit community hospital offering a range of healthcare services.
St. Joseph's Hospital	350 North Wilmot Road, Tucson, AZ 85711	Full-service hospital providing emergency and specialized medical care.
Davis-Monthan Air Force Base	3550 S Craycroft Rd, Tucson, AZ 85707	Military base supporting air combat and reconnaissance missions.
Pima County Emergency Operations Center	3434 East 22nd Street, Tucson, AZ 85713	Coordinates disaster response and emergency management efforts.
Sun Tran Bus Depot	3920 N Sun Tran Blvd, Tucson, AZ 85705	Central hub for public transportation services in Tucson.
Tucson Unified School District Headquarters	1010 East 10th Street, Tucson, AZ 85719	Administrative center overseeing public schools in the district.
Arizona Department of Transportation (ADOT) Tucson District Office	1221 S 2nd Avenue, Tucson, AZ 85713	Manages state transportation infrastructure and services in the Tucson area.

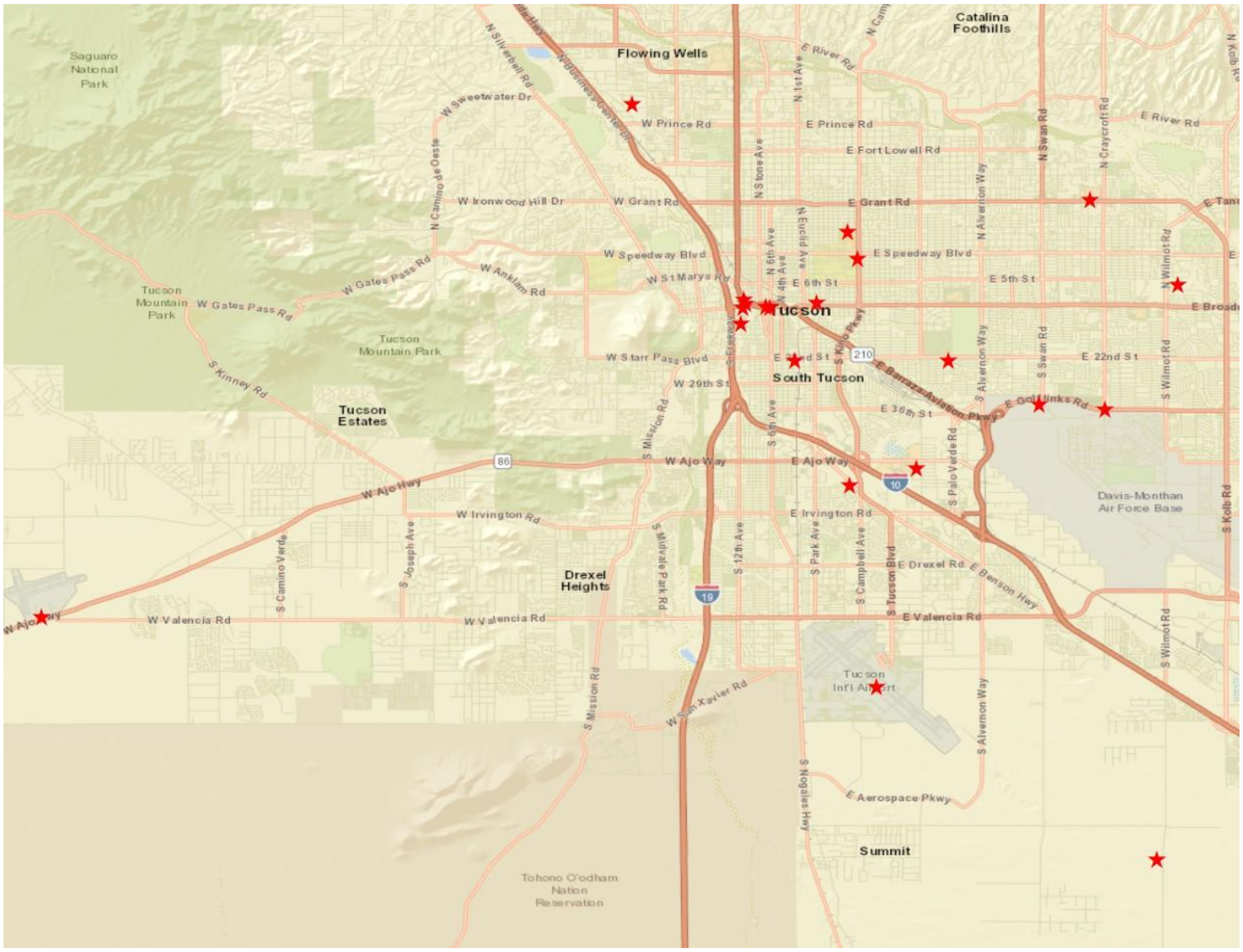


FIGURE 7-1. POTENTIAL MICROGRID LOCATIONS

Implementing microgrids at these locations would enhance their operational resilience, ensuring uninterrupted services during power outages or environmental events.

To enhance community resilience during high-temperature events and potential utility outages, the City of Tucson operates community centers that can serve as cooling centers. These facilities provide safe, air-conditioned spaces for residents to seek refuge from extreme heat. Below is a list of city-owned community centers that have been designated as cooling centers, and which could be screened Microgrid deployment:

TABLE 7-3. POTENTIAL COOLING CENTER LOCATIONS

Community Center Name	Address	Notes
Donna R. Liggins Center	2160 N. 6th Ave., Tucson, AZ 85705	Offers various recreational programs and serves as a cooling center during summer months.
El Pueblo Activity Center	101 W. Irvington Rd., Building #9, Tucson, AZ 85714	Provides community services and functions as a cooling center during high-temperature periods.
El Rio Center	1390 W. Speedway Blvd., Tucson, AZ 85745	Hosts community activities and operates as a cooling center when needed.

Community Center Name	Address	Notes
Freedom Center	5000 E. 29th St., Tucson, AZ 85711	Offers recreational facilities and serves as a cooling center during heat advisories.
Morris K. Udall Center	7200 E. Tanque Verde Rd., Tucson, AZ 85715	Provides various community programs and functions as a cooling center during summer months.
Randolph Center	200 S. Alvernon Way, Tucson, AZ 85711	Offers recreational activities and serves as a cooling center during high-temperature periods.

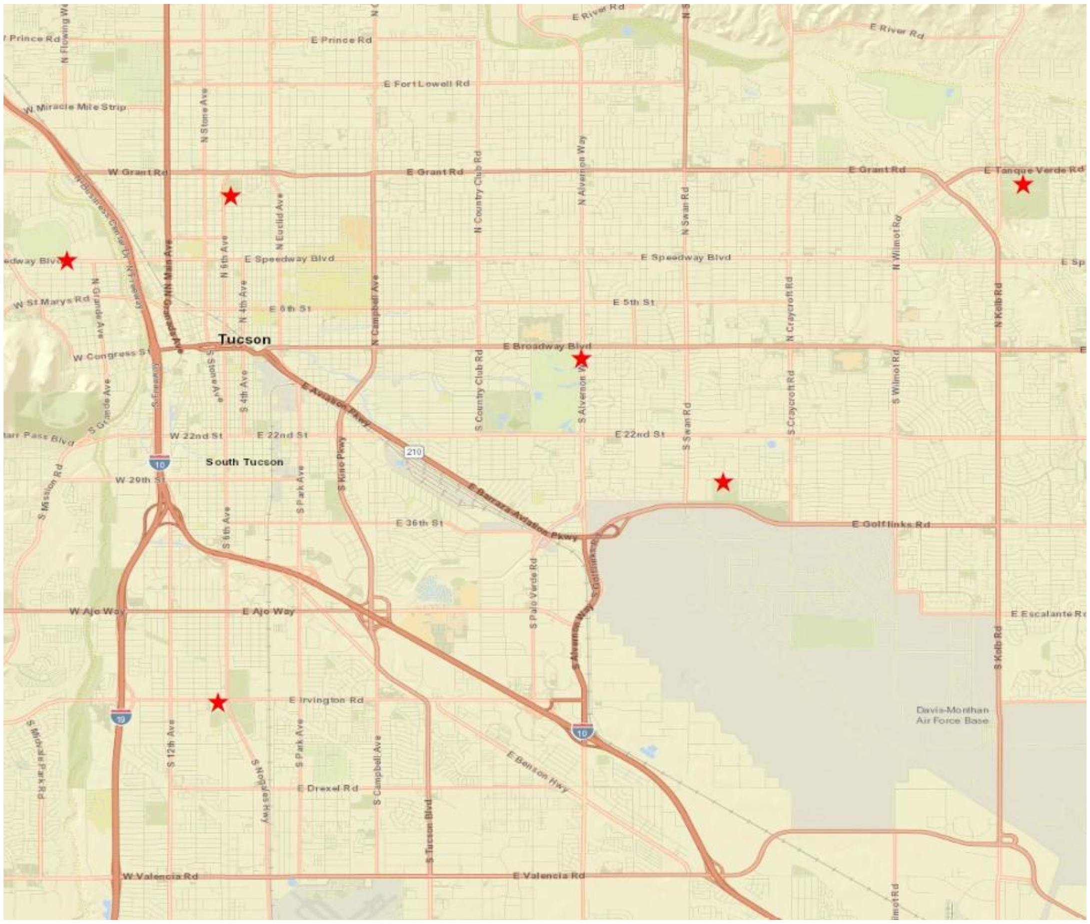


FIGURE 7-2. COMMUNITY CENTERS THAT COULD ACT AS COOLING CENTERS

7.8 SOLAR AND STORAGE SIZING & PRICING FOR EXAMPLE MICROGRID APPLICATIONS IN TUCSON

A key step in the development of the microgrid is identifying and understanding the facility's critical electric load. Operational needs during a grid outage event will fluctuate depending on the facility's purpose and uses. For example, facilities that operate as emergency shelters may reach full capacity for extended periods of time, so HVAC systems, lighting, computer systems, and critical loads may need to operate under atypical patterns; while Emergency Services facilities would need to maintain normal functionality to serve the community during outage events, so fuel pumps, communications equipment, and computer and security systems may be considered critical.

Identification of critical electric loads, how they operate and how the facility can be operated in energy conservation mode during emergency events is critical in minimizing the cost. The load assessment needs to determine which building systems can be shut down and which areas of the building can be isolated to reduce electric loads during the emergency event. Reducing electrical requirements by reducing lighting to minimum levels, changing thermostat settings, cycling HVAC equipment, turning off unneeded equipment, etc. should be reviewed during the feasibility analysis process. Often a building's electric requirement can be reduced by 50% with proper energy management. Below are detailed examples of solar and storage sizing, including rationale related to outage duration and solar charging capabilities, along with component-based cost estimates.

1. Example Potential Community Cooling Center Microgrid

Estimated Critical Portion of Load:

- Peak Load: ~150 kW (includes cooling, lighting, essential electronics)
- Average Daily Energy Usage: ~1,200 kWh/day

Solar PV Sizing:

- Potential Capacity: 300 kW
  - Sized above peak load to ensure ample daytime power and surplus to recharge storage.
  - Typical Cost: ~$1,750[152]/kW installed
  - **Total Solar Cost:** 300 kW × $1,750/kW = **$525,000**
- In a case where a SSA already exists at a location, then that portion of the cost of solar would be mitigated.

Energy Storage Sizing:

- Potential Capacity: 600 kWh
  - Sized to reliably cover critical loads during short-duration outages (up to 2-4 hours) and to ensure operations overnight or during cloud coverage periods when solar output is minimal.
  - Solar array provides sufficient daytime energy to recharge battery storage fully daily.
  - Typical Cost: ~$500/kWh[153] installed
  - **Total Storage Cost:** 600 kWh × $500/kWh = **$300,000**

Microgrid Controller and Balance of System:

- Controller & Management Systems: ~$150,000

[152] https://atb.nrel.gov/electricity/2024/commercial_pv
[153] https://atb.nrel.gov/electricity/2024/utility-scale_pv

- Interconnection and Protection Systems: ~$80,000
- Installation, Permitting, and Engineering: ~$100,000

Cost Summary:

Component	Cost ($USD)
Solar PV (200 kW)	$525,000
Battery Storage (400 kWh)	$300,000
Microgrid Controller & Software	$150,000
Interconnection & Protection	$80,000
Microgrid Controller Installation & Engineering	$100,000
Total Estimated Cost:	**$1,155,000**

2. Example Potential Hospital Critical Load Microgrid

Estimated Critical Portion of Load:

- Peak Load: ~2 MW (critical emergency services, medical equipment, HVAC, lighting)
- Average Daily Energy Usage: ~30,000 kWh/day

Solar PV Sizing:

- Potential Capacity: 3 MW
  - Provides ample daytime energy exceeding peak demands, allowing significant surplus for daily battery recharging.
  - Typical Cost: ~$1,500/kW[154] installed
  - **Total Solar Cost:** 3,000 kW × $1,500/kW = **$4,500,000**

Energy Storage Sizing:

- Potential Capacity: 6 MWh
  - Sized for sustained critical load support during longer-duration outages (4-8 hours or overnight), ensuring reliability for essential healthcare services.
  - Solar capacity ensures adequate energy to fully recharge storage daily under normal operating conditions.
  - Typical Cost: ~$425/kWh[155] installed
  - **Total Storage Cost:** 6,000 kWh × $425/kWh = **$2,550,000**

Microgrid Controller and Balance of System:

- Advanced Controller & Management Systems: ~$500,000
- Interconnection and Protective Equipment: ~$400,000
- Installation, Permitting, and Engineering: ~$500,000

[154] https://atb.nrel.gov/electricity/2024/utility-scale_pv
[155] https://atb.nrel.gov/electricity/2024/utility-scale_battery_storage

Cost Summary:

Component	Cost ($USD)
Solar PV (3 MW)	$4,500,000
Battery Storage (6 MWh)	$2,550,000
Microgrid Controller & Software	$500,000
Interconnection & Protection	$400,000
Installation & Engineering	$500,000
Total Estimated Cost:	**$8,450,000**

Integration into Utility Integrated Resource Plan (IRP):

If solar generation and battery storage systems within the microgrid align with and support the larger utility's (TEP) IRP, contributing to grid-wide reliability, capacity, and renewable energy goals, potentially 60-80% of the microgrid's total costs (primarily solar and storage components) could effectively be offset or diminished. The incremental cost of microgrid deployment would thus primarily focus on non-generation and non-storage related components, including microgrid controllers, protective equipment, interconnection systems, and associated O&M expenses.

TABLE 7-4. COMPARATIVE COST SUMMARY WITH AND WITHOUT UTILITY UTILIZATION

Scenario	Community Cooling Center Cost ($USD)	Hospital Critical Load Cost ($USD)
Without Utility Integration	$1,155,000	$8,450,000
With Utility Integration (80%)	$462,000	$1,690,000

This synergy between the microgrid and broader utility infrastructure highlights significant potential cost savings and enhanced operational value achievable through strategic planning and integration.

7.9 BASIC GUIDE FOR MICROGRID DEPLOYMENT IN TUCSON

STEP 1: Establish Clear Goals

Identify the city's primary goals for deploying microgrids, such as:
- ☐ Enhancing reliability and resiliency of power supply
- ☐ Providing safe community spaces during outages (e.g., cooling and resilience hubs)
- ☐ Increasing renewable energy integration and sustainability
- ☐ Supporting critical infrastructure and industrial operations

STEP 2: Identify Potential Sites and Locations

Select strategic sites aligning with established goals, including:
- ☐ Critical healthcare and emergency response facilities
- ☐ Community resilience centers, such as cooling hubs and recreation centers
- ☐ Industrial and commercial areas requiring reliable, high-quality power
- ☐ Educational and research institutions emphasizing sustainability and innovation

STEP 3: Understand and Collaborate with Tucson Electric Power

Engage TEP early and regularly:
- ☐ City and TEP to review grid conditions at potential microgrid locations
- ☐ Ensure compliance with interconnection rules as outlined by the ACC and TEP's Interconnection Manual.
- ☐ Collaborate with TEP to access grid reliability data to strategically identify optimal microgrid locations.
- ☐ Foster a partnership approach for shared community and utility benefits.

STEP 4: Identify and Select Suitable Components

Design microgrids with key components to match specific site needs, including:

- ☐ Renewable generation (solar, wind)
- ☐ Energy storage systems (batteries)
- ☐ Backup generation (diesel, CHP)
- ☐ Advanced controllers and sensors for energy management

STEP 5: Conduct Feasibility Assessment and Economic Justification Analysis

Perform a comprehensive economic analysis involving:

- ☐ Cost-benefit analysis (CBA)
- ☐ Lifecycle cost analysis (LCA)
- ☐ Sensitivity analysis for varying operational scenarios
- ☐ Quantification of resilience and reliability benefits
- ☐ Acknowledge potential higher average energy costs but justify with increased safety, reliability, and environmental benefits.

STEP 6: Implement and Evaluate

Carefully execute the implementation with continuous stakeholder engagement, clearly documenting processes and outcomes. Evaluate system performance regularly against stated objectives to inform future expansions or adjustments.

This structured approach positions Tucson effectively to leverage microgrids for enhanced resiliency, sustainability, and community safety.

APPENDIX A. Acronyms

A&G	Administrative and general
AZISA	Arizona Independent Scheduling Administrator Assessment
CCA	Community Choice Aggregation
CT	Combustion Turbine
CIP	Capital Improvement Program
ECA	Electric Competition Act
FERC	Federal Energy Regulatory Commission
IRP	Integrated Resource Plan
ISO	Independent System Operator
OATT	Open Access Transmission Tariff
O&M	Operation and maintenance
PILOT	Payment in lieu of taxes
NERC	North American Electric Reliability Corporation
RA	Resource Adequacy
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standard
SCC	Social Cost of Carbon
SCF	Standard cubic foot is defined as one cubic foot of gas at 60 ^{o}F
SSA	Solar Service Agreement
TEP	Tucson Electric Power
VPPA	Virtual Power Purchase Agreement
WACC	Weighted Average Cost of Capital
WREGIS	Western Renewable Energy Generation Information System

APPENDIX B. Glossary of Terms

AB:	Assembly Bill
Ancillary Services:	Those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system.
Base Case:	The base case is defined as the expected case involving expected power prices and electric loads.
Bundled:	Receive all their services (transmission, distribution and supply) from the Investor-Owned Utility.
California Independent System Operator (CAISO):	The organization responsible for managing the electricity grid and system reliability within the former service territories of the three California IOUs.
City:	City of Tucson
Firming:	Firm capacity is the amount of energy available for production or transmission that can be (and in many cases must be) guaranteed to be available at a given time. Firm energy refers to the actual energy guaranteed to be available. Firming refers to the financial instrument to change non-firm power to firm power.
Green Tariff Program:	TEP customers can elect to purchase up to 100% renewable energy through TEP's voluntary Green Tariff Program.
GW	Gigawatt equal to 1,000 MW.
GWh:	Gigawatt Hours equal to 1,000 MWh.
Intertie:	transmission line that forms part of an interconnection.
kV:	kilovolt, 1,000 volts, a unit of electrical potential.
kW:	Kilowatt, equal to 1,000 watts, is measure of electric demand.
kWh:.	Kilowatt Hour.
Load Forecast:	A forecast of expected load over some future time horizon. Short-term load forecasts are used to determine what supply sources are needed. Longer-term load forecasts are used for budgeting and long-term resource planning.
Load Factor:	Ratio of actual energy consumption to maximum possible consumption based on peak electric load.

MW:	Megawatt equal to 1,000 kW.
MWh:	Megawatt Hours equal to 1,000 kWh.
N-1:	Refers to contingency when there is a loss of any one system component to maintain electric service.
Palo Verde:	Nearest wholesale electricity trading hub.
Resource Adequacy (RA):	The requirement that a Load-Serving Entity own or procure sufficient generating capacity to meet its peak load plus a contingency amount (15% in California) for each month.
Renewable Portfolio Standard (RPS):	The state-based requirement to procure a certain percentage of load from RPS-certified renewable resources.
Retail Rates:	Rates charged by electric distribution utility for service provided to end-use customers. Retail rates may include distribution, transmission, and power supply services.
Shaping:	Function that facilitate and supports the delivery of energy generation to periods when it is needed most.
Wheeling:	the transportation of electricity from within an electrical grid to an electrical load outside the grid boundaries.
Wholesale Power:	Large amounts of electricity that are bought and sold by utilities and other electric companies in bulk at specific trading hubs. Quantities are measured in MWs, and a standard wholesale contract is for 25 MW for a month during heavy-load or peak hours (7 am to 10 pm, Mon-Sat), or light-load or off-peak hours (all the other hours).

APPENDIX C. Plan for Outreach to Local, Public Utilities Around the City of Tucson to Seek Interest in Potential Partnering for Provision of Utility Services

We have prepared a Request for Statements of Interest (RFI) which Tucson may issue to interested parties AFTER the City determines that it wishes to proceed with further investigating creation of a City public power utility and identifying partners who may assist in the investigation, creation, implementation, start-up and operations of a new public utility. We have identified local public utilities who may provide assistance, likely through the sharing of existing resources (systems and labor), and shared utility resource organizations in the region.

A Request for Statements of Interest (RFI) is a commonly used document to gauge interest in potential partners, contractors, or service providers who may be willing to offer resources to help Tucson evaluate and implement a public power utility. Responses to the RFI are used in a subsequent development of a Request for Proposals or Request for Qualifications of partners, contractors or service providers. Should Tucson electeds determine to move forward with next steps towards the development of a City public power utility, the following next steps are likely in acquiring service partners:

1. Develop a Tucson Public Power Utility Transition Plan which will further detail the services needed, how the services may be acquired, and a schedule indicating when services and resources are needed.
2. Issue the RFI to interested parties; the likely ones are listed in this document. The draft RFI is included with this document.
3. Receive RFI responses, meet with respondents and determine the scope, schedule of availability, and necessary steps for potentially acquiring services and resources.
4. Where appropriate, develop competitive solicitations to specify services and resources desired, when desired, and then determine their costs from received bids.
5. Negotiate and execute contracts with service providers.

We have identified certain nearby and neighboring municipal electric utilities and electric cooperatives who are likely to have some interest in supporting the development, implementation and initial operations of a Tucson public power utility. These utilities and their proximity to Tucson are identified in the attached Map of Electric Utilities in Arizona. We have also identified statewide electric utility shared resource organizations that provide services to municipal electric utilities and electric cooperatives. These are all listed below and should be sent the RFI.

Name	Type	Territory	Customers
Salt River Project	Municipal	Central Arizona	1,100,000
City of Tucson	Municipal	Tucson	250,000
Sulphur Springs Valley Electric Cooperative	Co-op	Southeastern Arizona	60,000
Trico Electric Cooperative	Co-op	Peyton	57,000
Graham County Electric Cooperative	Co-op	Graham County	8,400
Navopache Electric Cooperative	Co-op	Central Eastern Arizona	N/A

AMERICAN PUBLIC POWER ASSOCIATION

The American Public Power Association (APPA) is the voice of not-for-profit, community-owned utilities that power approximately 2,000 towns and cities nationwide. APPA represents public power before the federal government to protect the interests of the more than 55 million people that public power utilities serve across the United States and its territories. APPA advises on electricity policy, grid technology and operations, and workforce development in support of safe, modern, and resilient utilities.

APPA provides networking opportunities for members around common issues and challenges, advocates for public power in legislative and regulatory venues, provides education to utility staff on technologies and regulatory matters, provides technical training, advances research and development, provides industry news and events updates, and coordinates disaster recovery and mutual aid programs.

ARIZONA POWER AUTHORITY

The Arizona Power Authority (Authority), a body corporate and politic of Arizona, was formed as a result of federal legislation (Boulder Canyon Project Act of 1928) that allocated a portion of power produced from the Boulder Canyon Project (Hoover Dam and Power Plant). Hoover power first became available in 1936, and at that time, the State had not developed an infrastructure and methodology to receive and distribute this allocated power. Subsequently, in 1944, the state of Arizona's Legislature created the Authority (as set forth in Title 30, Arizona Revised Statutes) charging the Authority with the responsibility of acquiring and marketing Arizona's share of Hoover power.

The Authority has worked effectively with both publicly-owned and privately-owned utilities in making Hoover Power Plant hydro power available to all major load centers throughout Arizona at the lowest possible cost. It has also provided leadership in meeting the many challenges brought about by the constant changes in the electric utility industry.

ARIZONA MUNICIPAL POWER USERS ASSOCIATION

The Arizona Municipal Power Users Association (AMPUA) is an association of Arizona public and consumer-owned power entities, including irrigation districts, electrical districts, electric cooperatives, municipally owned electric systems, Salt River Project, and Central Arizona Project[156]. AMPUA represents and advocates for the interests of its member utilities and helps shape the future of energy policy and regulation in Arizona

GRAND CANYON STATE ELECTRIC COOPERATIVE ASSOCIATION

Grand Canyon State Electric Cooperative Association, Inc. (GCSECA) is a community-focused electric cooperative association created to aid in and champion the needs of Arizona's rural electric cooperatives in providing

[156] Near-term Colorado River Operations – Revised Draft SEIS (October 27, 2023)

affordable, safe, reliable and sustainable energy to more than 213,522 homes, businesses, farms, and schools. GCSECA and its co-op members invest in our communities through various customer programs.

Colorado River Energy Distributors Association

CREDA (Colorado River Energy Distributors Association) is a non-profit organization representing consumer-owned electric systems that purchase federal hydropower and resources of the Colorado River Storage Project (CRSP). CREDA was established in 1978, and serves as the “voice” for its members in dealing with the Bureau of Reclamation (as the generating agency of the CRSP) and Western Area Power Administration (WAPA) (as the marketing agency of the CRSP). CREDA members are all non-profit organizations, serving over 5 million electric consumers in the six western states of Arizona, Colorado, Nevada, New Mexico, Utah and Wyoming.

Southwest Public Power Agency (SPPA)

SPPA, created as a Joint Action Agency, is a collection of irrigation and electrical districts, tribal and municipal electric utility service providers in Arizona. Formed to optimize economies of scale on a project by project basis, SPPA bylaws allow for members to “opt-in” or “opt-out” based on the best interest of the individual members. Costs per project are based on parties’ participation, and administration and general expenses are based on a pro-rata allocation approved by the SPPA Board.

APPENDIX D. Tucson Public Power Utility Request for Statements of Interest for Partnering Services

INTRODUCTION

The City of Tucson (City) is examining the formation of a City public power utility. The City has commissioned a public power utility formation feasibility study and may put to a ballot vote whether to renew its electric utility franchise agreement with Tucson Electric Power (TEP).

In May of 2025, GDS Associates, Inc. (GDS) completed a Feasibility Study to determine the financial viability of a Tucson public power utility; that is, could a public power utility serving Tucson city ratepayers acquire the TEP distribution system assets, create and operate the utility, and offer rates equal to or lower than TEP rates. The results of the GDS Feasibility Study determined that a Tucson Municipal Electric Utility is financially viable.

With the Franchise Agreement vote and the results of the Public Power Feasibility Study, the Tucson City Council must determine whether to move forward with creating a public power utility or renegotiate the Franchise Agreement with TEP. As part of this further investigation, the City seeks to determine the interest of contiguous and nearby publicly owned utilities and electric co-operatives in providing short-term, long-term or permanent services to a Tucson public power utility during the transition period to developing the utility, during initial operations of the utility, or under long-term or permanent operations of the utility.

This Request for Statements of Interest for Partnering Services (RFI) is issued to determine the level of interest of interested parties is assisting the Tucson public power utility with these services under yet to be determined partnering arrangements.

NEEDS OF THE TUCSON PUBLIC POWER UTILITY

The range of services a newly created Tucson public power utility would need include, generally, those listed below. A more detailed description of the services categories' requirements, standards, timing and level of provision are provided further in this RFI.

- *Transition Planning & Development*
- *System Construction, Operations & Maintenance*
- *System Planning & Engineering*
- *Customer Services*
- *Marketing, Outreach & Education*
- *Finance & Accounting*
- *Power Supply & Delivery*
- *Risk Management*
- *Legal &Regulatory*
- *Administrative Support Services*
- *Human Resources*
- *Billing & Customer Information Systems*
- *Data Management*
- *Fleet Management & Maintenance*
- *Information Technology Systems*
- *Emergency Management Services*

BACKGROUND

The Tucson Public Power Study was completed in May of 2025. The Study identified the scope of the TEP electric system to be purchased by Tucson, a cost estimate for purchasing the system, stranded costs to be paid by Tucson to TEP to hold their remaining customers harmless for investments TEP has made (and will make) on behalf of Tucson customers, a high-level schedule for purchasing the TEP system assets and initiating operation of a Tucson public power utility, and a financial pro forma that determined that Tucson can purchase and operate the TEP distribution system while holding rates equal to or lower than TEP. Two milestones will determine if Tucson will engage in conversations with neighboring utilities for partnering on services:

1. The Tucson electorate votes later in 2025 to NOT renew the Tucson Electric Franchise Agreement in Tucson, AND
2. The Tucson City Council determines that it wishes to proceed with further investigation of creating a Tucson public power utility.

The information provided for now within this RFI is to provide advance notice and status of the investigation by Tucson. For now, our questions to potential partners are:

1. **Would your organization be interested in discussing providing under some type of partnering or contracting arrangement any of the services described in this RFI?**
2. **If so, which ones? Or are there other services you believe would be beneficial to Tucson that you might provide?**
3. **What legal or other technical, administrative, governance steps would be necessary for your organization to undertake discussions for providing and/or partnering in any of these services?**

The map below shows the relative location of the City of Tucson relative to public power utility and electric cooperative service territories. Tucson is situated in Tucson Electric Power territory.

RFI TIMELINE AND RESPONSES

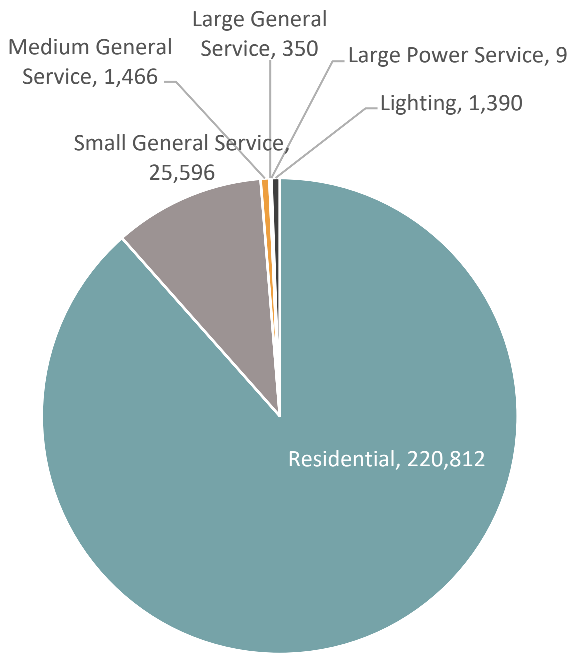
Date RFI Issued:	TBD
Deadline for Questions about RFI:	TBD
Deadline for Responses to Questions about RFI:	TBD
Deadline for Responding to RFI:	TBD

TUCSON SYSTEM INFORMATION

Below are data regarding the TEP loads, distribution system and accounts served in the City of Tucson.

2023 TUCSON UTILITY STATISTIC

	Residential	Small General Service	Medium General Service	Large General Service	Large Power and High Voltage	Lighting	Total
Number of Service Accounts							
Inside Tucson	2,001,065	701,667	594,090	749,773	509,475	12,423	4,568,492
Outside Tucson	2,204,320	432,502	351,468	438,043	1,575,323	10,406	5,012,062
Total	**4,205,385**	**1,134,169**	**945,558**	**1,187,816**	**2,084,797**	**22,829**	**9,580,554**
Retail Sales, MWh							
Inside Tucson	220,812	25,596	1,466	350	9	1,390	249,622
Outside Tucson	179,765	11,602	740	242	53	364	192,767
Total	**400,577**	**37,198**	**2,206**	**592**	**62**	**1,754**	**442,389**



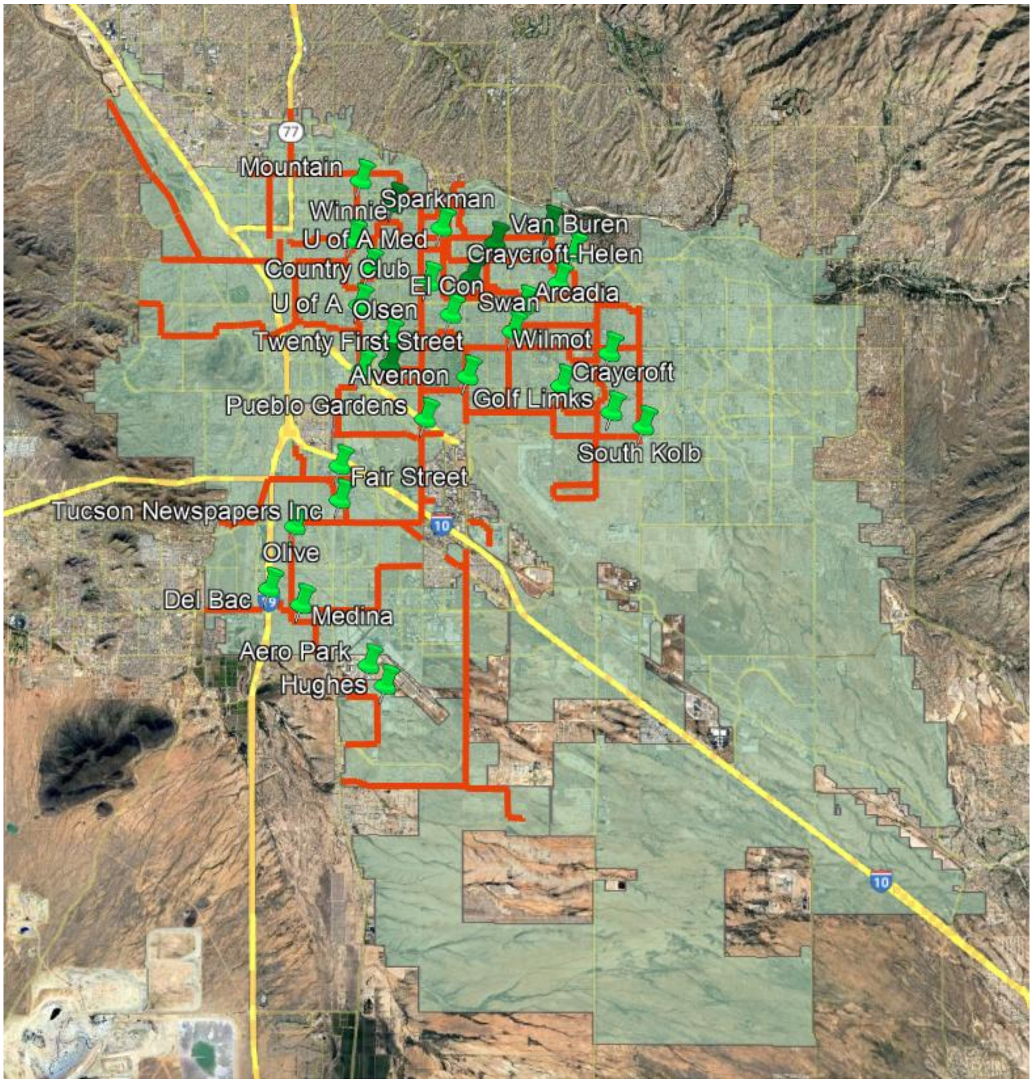
CITY OF TUCSON SERVICE ACCOUNTS

TUCSON ELECTRIC ENERGY FERC TRANSMISSION AND DISTRIBUTION SUBSTATIONS – CITY OF TUCSON

46kV Substations to be Acquired	
Substation	**Voltage**
Aero Park	46kV
Alvernon	46kV
Arcadia	46kV
Country Club	46kV
Craycroft	46kV
Craycroft-Helen	46kV
El Con	46kV
Fair Street	46kV
Golf Links	46kV
Grant	46kV
Hedrick	46kV
Hughes	46kV
Medina	46kV
Mountain	46kV
North Alvernon	46kV
Olive	46kV
Olsen	46kV
Pueblo Gardens	46kV
Sears	46kV
Shannon	46kV
South Kolb	46kV
Sparkman	46kV
Swan	46kV
Tucson Med Center	46kV
Tucson Newspapers Inc	46kV
Twenty First St	46kV
U of A Med	46kV
U of A	46kV
Van Buren	46kV
Warehouse	46kV
Wilmot	46kV
Winnie	46kV

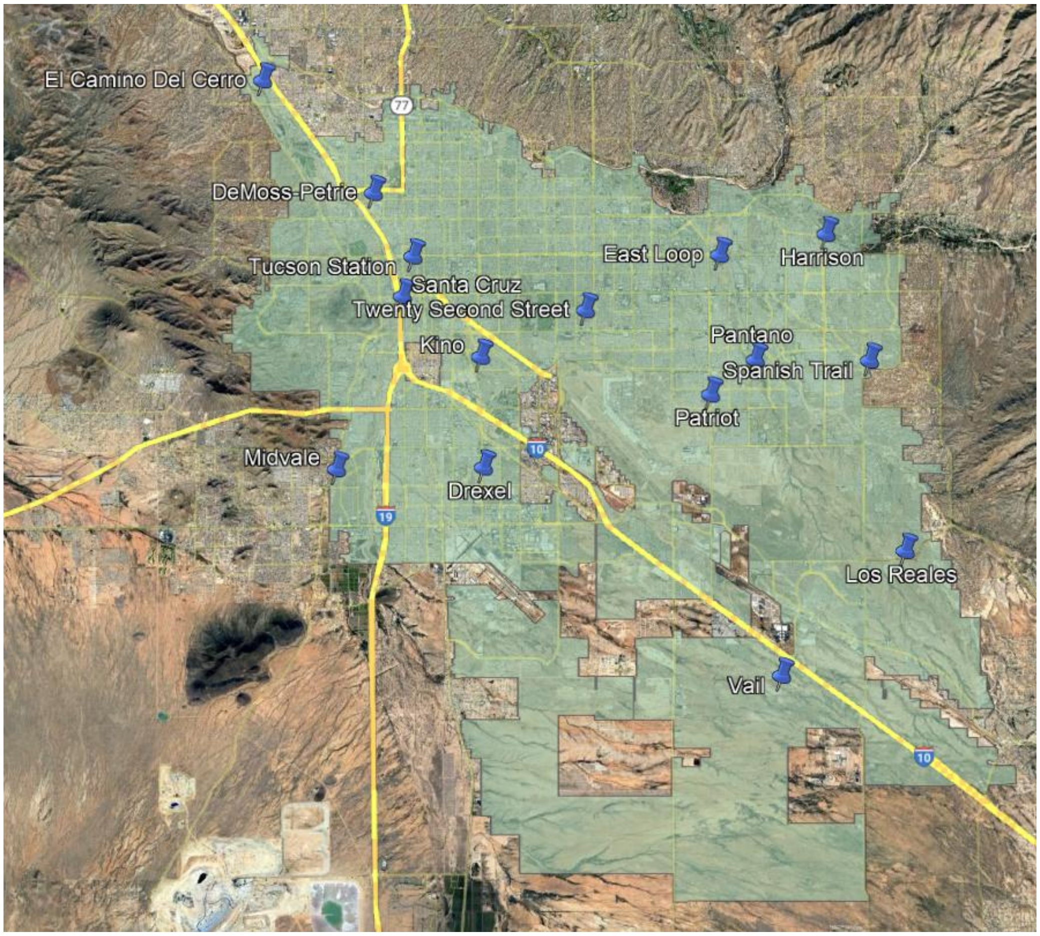
115kV Substations to be Acquired	
Substation	**Voltage**
DeMoss Petrie	115kV
Drexel	115kV
El Camino Del Cerro	115kV
Harrison	115kV
Kino	115kV
Los Reales	115kV
Midvale	115kV
Pantano	115kV
Patriot	115kV
Rillito	115kV
Santa Cruz	115kV
Spanish Trail	115kV
Tucson Station	115kV
Twenty Second Street	115kV
Vail	115kV

For the transmission and substation facilities, all 46kV substations and 46kV transmission lines within the city limits would be acquired. The study assumes the separation of the 46kV transmission lines will be the point where the line crosses the City boundary. Because the City can only acquire facilities within the city limits, the separation is made at the edge of the City Limits. However, in the future, a point of demarcation could be determined such that ownership changes at the termination point of the transmission line such as at a substation or disconnect switch. GDS utilized Google Maps to establish the location of the 46kV substations and 46kV transmission lines within the City Limits. These assets are shown in the figure below.



46KV TRANSMISSION LINES AND 46KV SUBSTATIONS WITH THE CITY LIMITS

For 115kV transmission lines, it is assumed that TEP will continue to own and operate these facilities. For 115kV distribution substations located in the City Limits which serve customers within the City Limits, the assumption is the City will take transmission service at these substations. It is further assumed that TEP will continue to own and operate the 115kV breakers, 115 kV high side bus works, and that the point of delivery to the City will be the high side of the power transformer in the substation. The City will acquire and operate the power transformers, voltage regulation, and low side distribution protective devices such as breakers and relays. The following map depicts the 115 kV substations to be acquired.



115KV SUBSTATIONS WITH THE CITY LIMITS

DESCRIPTION OF THE SYSTEMS CONSIDERED FOR PARTNERING SUPPORT

Construction, Operations & Maintenance

Construction, Operations and Maintenance (COM) consists of resources and activities necessary to operate and maintain the transmission and distribution system. COM includes overhead and underground line crews that perform routine or planned work, such as new construction or maintenance and emergency work. This department also includes system monitoring and dispatchers, meter readers and technicians, warehousing functions, and vegetation management. These services will be needed to transition operations of these systems from TEP to the Tucson public power utility prior to an anticipated January 2028 initial operation date. Overall, it is estimated that likely 2/3 of proposed public power utility positions will reside in COM.

Electric utility construction, operations and maintenance require some skill sets not currently available within the Tucson's organization. Reliable operations depend on comprehensive knowledge of electric systems and applicable safety and environmental codes and practices. It is recommended that initially the public power utility leverage experienced contract crews for the majority of COM positions rather than build these skill sets internally. Depending on the long-term cost effectiveness of this approach, the City may eventually decide to hire internal staff to implement some or all the required functions. This outsourcing scheme has been successfully implemented by large investor-owned utilities, electric cooperatives, and electric municipal utilities. The Tucson public power utility seeks through this Request for Statements of Interest to gauge whether neighboring and nearby municipal utilities might be interested in, initially or over the long term, augmenting their existing COM services to support the Tucson public power utility.

These COM services should also include adequate workspace for crews consisting of workshops, warehousing, storage/laydown yards, and shelters for equipment and fleet needs. A separate communications center is needed for 24-hour monitoring, control, dispatch and emergency response. timely information and coordination with Xcel for customer meter data access, outage management, and emergency response. Transition planning of these functions will assume that knowledge of, and access to, TEP's distribution system data and monitoring systems.

Also, multiple operating procedures, standards and policies must be in place prior to any crews working on the system. The majority of these are produced through the planning and engineering function that controls system design criteria, which is further augmented with maintenance procedures. The Tucson public power utility may use or amend standards and procedures made available by interested parties to this RFI or the Tucson Electric standards and policies.

Customer Service

The Customer Service function encompasses billing and collections, call center representatives, and account management. The Tucson public power utility's goal is to have the ability to bill customers and provide related services upon acquisition of assets, well prior to public power utility initial operations.

The Tucson public power utility may either develop a new CIS in time to meet initial operations or expand a current system utilized by an interested party. It is imperative that the Tucson public power utility receive accurate and complete account information from TEP in a timely manner to meet either option. Account information includes, but is not limited to, customer name, address, account number, GIS location, special medical needs, current rate, meter specifications, multipliers, meter read cycle, participation in customer programs and rebates, installed generation, and billing history. We anticipate significant lead time will be needed to implement a CIS system, and at the point that it goes "live," the Tucson public power utility must be prepared to read meters or import meter data, bill customers, and respond to general inquiries or requests for service. Customer account transition demands heavy coordination with Tucson Electric to minimize service disruptions and to ensure that customers clearly understand when and how to contact the Tucson public power utility rather than Tucson Electric.

Staffing needs will consist of a Customer Service Manager with additional support positions for various functions. It is possible that the Tucson public power utility may utilize or expand existing Tucson utility services for electric billing and collections and call center functions; or they may be outsourced to interested parties' resources.

A cross-functional input critical to CIS implementation is retail rate design. Upon initial operations, the Tucson public power utility anticipates applying retail rates under which customers will be billed. The rates may or may not reflect TEP's current or future retail rate structures. Integral to rate design are budget information (driven by load forecasts, end-use programs and power supply costs), customer classifications, public processes and City Council action. The Tucson public power utility is open to the offering of these services prior to initial operations.

Energy Services

An additional customer-related function is Energy Services, which includes end-use program development, branding, marketing and communications. This section will not only be important in facilitating and communicating changes that directly affect customers during the transitional period, it will also drive local initiatives to meet any Tucson public power utility goals for electricity supply, delivery and consumption management. This work will be led by an Energy Services Manager with support staff. The Tucson public power utility is open to interested parties' offering of staffing or services prior to initial operations. Ultimately, Energy Services is expected to grow as the number of customer programs, such as energy efficiency, demand side management, and distributed (customer owned) renewables, increases over time.

Ideally, the Energy Services group would ensure that programs requiring continued incentives or administration are identified and integrated into the new electric utility operation. Concurrently, this group will also prepare for new offerings and services. This will involve research in the viability of innovative programs and pilots to include incentive amounts, customer adoption rate, contribution to carbon goals, cost-benefit analysis, and impacts on grid operations and power supply. The Energy Services group will work closely with Resource Planning, Finance, and Engineering to ensure that programs complement power supply requirements while meeting budget targets and technical standards for grid operations. Most importantly, Energy Services must coordinate with Customer Service such that the departments are unified in the communication, implementation and administration of programs, including measurement and verification of local impacts.

Finance & Accounting

The majority of finance and accounting functions for the Tucson public power utility are similar to those in the City of Tucson's current organization and will require incremental staff additions to manage additional workload. The Tucson public power utility currently anticipates that a Finance and Accounting Supervisor and perhaps other support positions will be hired during the transition period to help implement this work. Skill sets and systems to support budget and rate making activities that utilize the Governmental Accounting Standards Board ("GASB") for accounting and financial reporting, and also maintain books and records in accordance with the Federal Energy Regulatory Commission's Uniform System of Accounts ("FERC Accounting") will be utilized.

The Finance and Accounting group will be heavily involved in coordinating preliminary budgets, cost of service studies, and rate design to meet specific timeline targets. This requires expansion of current systems. These may be synchronized with the City of Tucson's existing Finance and Accounting system or they may be made part of an expanded, existing Finance and Accounting system from an interested party. Concurrently, budget inputs must be obtained from other functional areas, including operations and power supply. Budget and customer classifications drive retail rate design, which the Tucson public power utility may develop or may choose to adopt TEP rate structures. The retail rate structures must be approved in advance of permanent financing and also in time to program a new customer information system for live testing prior to initial operations. Finance and Accounting services are data intensive and time sensitive. Eventually, financial models must be refined to support ongoing integrated resource planning ("IRP") analysis and critical decisions for future power supply portfolios and innovative retail rate structures. The Tucson public power utility must also expand, implement new, or utilize interested parties' asset management and work order systems capable of integrating with customer billing, accounting, and financial systems.

Planning & Engineering

The Planning and Engineering department of an electric utility is responsible for developing and managing engineering standards for construction, operations, and maintenance of the system. This includes adopting appropriate policies and procedures for day-to-day activities as well as long-range planning related to systems operation maintenance and capital asset replacement. In all cases, safety and reliability are of paramount importance. Policies and procedures must adhere to codes and regulations, including the National Electrical Safety Code ("NESC"), Occupational Safety and Health Administration ("OSHA") Standards, and Environmental Protection Agency ("EPA"). It is expected that the Boulder electric utility will follow industry "good utility practice" and "best practices" in addition to those adopted by the City.

The Tucson public power utility anticipates that a Lead Engineer will be hired during the transition period to help implement this work. This position will coordinate data exchange with TEP, develop operating agreements, oversee engineering for separation and integration, and ensure that all appropriate standards and policies are in place prior to contractors working on the system. Support staff may be hired at later dates, recognizing that contractors may be utilized for some positions. The Tucson public power utility is also interested in offers from interested parties in providing these resources and services.

The initial transition activity is refining the system maps and the Geographic Information System ("GIS"), which includes verifying the accuracy of the existing mapped resources, as these are critical to the Tucson public power utility in identifying assets and their corresponding field location, condition, and additional attributes. Many utility processes, such as facility design and construction, outage prediction and management, inventory systems, and asset accounting, depend on system maps and GIS. Next, system modeling and studies must be performed using a software tool to simulate and analyze loads and power flows under various operating conditions. This comprehensive analysis allows the Tucson public power utility to assess the current performance of the system, ensuring that safety and reliability standards are achieved. Additionally, studies are used to evaluate alternatives for system improvements and expansion, serving as the basis for long-range planning and capital improvements.

Concurrent with maps and models, the planning and engineering group must adopt multiple standards including, but not limited to:

- Developer Standards
- Interconnection Standards
- Additional Facilities & Services
- Impact Fees & Charges
- Customer Rules & Regulations
- Service Contracts for Large Customers
- Substation, Transmission, Distribution Design Manuals
- Substation, Transmission, Distribution Materials & Construction Standards
- Substation, Transmission, Distribution System Planning Guidelines
- Comprehensive Utility Equipment Testing Procedures
- Right-of-Way Standards & Maintenance Procedures
- Meter Maintenance & Testing Standards

During transition, this work is coordinated by the Lead Engineer and may commence as early in the transition process as conceivable. The Tucson public power utility may provide the opportunity to base standards and procedures on TEP's guidelines or adopt alternatives. Most importantly, all standards must be in place prior to initial operations. The Tucson public power utility is interested in offers from interested parties to provide these resources and services.

Power Supply & Delivery

The major responsibilities of Power Supply and Delivery are integrated resource planning, wholesale power procurement and delivery, transmission service contracting, and portfolio dispatch and optimization. A key position will be the Resource Planner, responsible for coordinating these tasks, which are highly interdependent with other functions. Power supply is the single highest operational cost and is critical during the transition process, since it drives the Tucson public power utility's budget, retail rates, and estimated revenue stream. These components must be forecast in a timeframe and manner that meet permanent financing prerequisites. Additionally, firm power supply is critical to ongoing operations, and the Tucson public power utility must seek a cost-effective and reliable supply to serve customers under initial operations and for the near term.

As part of its integrated resource modeling process, the Tucson public power utility will likely create a 20-year load forecast using available data. Planning forecasts and models will be updated as necessary and must be estimated during the transition period. Also, the Tucson public power utility will be a new entrant in the wholesale market and must secure new wholesale power contracts to serve current and future load.

During the transition period, the Tucson public power utility must engage the market to evaluate potential resources that have the capability and flexibility to serve the customers on an uncertain date. Concurrently, the Tucson public power utility will assess options to continue receiving power from TEP. Lastly, the distribution system equipment for the Tucson public power utility to receive wholesale power supply at proposed delivery points under initial operations, whether provided by TEP or a third party, will not meet traditional infrastructure and metering requirements until the construction of systems which clearly separate the TEP system from the Tucson public power utility system. The Tucson public power utility must coordinate closely with TEP as the transmission provider to schedule delivery of wholesale power under their open access transmission tariff.

To manage or mitigate multiple challenges, the Tucson public power utility will incorporate early and rigorous evaluation of integrated resource inputs, including generation market assessments, distributed generation potential, load impacts from energy efficiency and demand side management, and transmission studies. The Resource Planner must directly implement or facilitate evaluations, assemble results, and determine a reliable power supply path that meets the Tucson public power utility risk and budgetary thresholds. This work is complex, time sensitive, and is subject to influence by legal and regulatory proceedings. Power supply and delivery functions will require external consultation and legal assistance to execute and file documents with regulatory agencies.

Ultimately, the Tucson public power utility must prioritize a power supply contract or commitment well in advance of initial operations to meet financing obligations and to ensure that associated transmission service may be obtained. Once firm supply is secured, the Tucson public power utility may initiate a more robust integrated resource planning process to direct long-range commitments that start on initial operations. Key inputs include generation cost projections and their sensitivities to drivers such as technology innovation, environmental regulation, distributed generation potential, customer end-use program penetration, and varying carbon goals. The Electric Utility Director will be heavily engaged in ongoing resource planning efforts that will also involve numerous stakeholders and incorporate public input. The Tucson public power utility is interested in offers from interested parties to provide these resources and services.

Legal/Regulatory

The Legal and Regulatory functions of the Tucson public power utility are expected to be managed by existing City of Tucson staff who will contract for assistance when necessary. During the transitional period, City of Tucson's legal department will likely oversee condemnation and regulatory matters with support from contracted support and counsel. The Tucson public power utility has not yet identified the legal strategy or anticipated outcomes. The Tucson public power utility will identify contracts, agreements or filings that are expected to be transferred from TEP or developed by the City to support the proceedings and formation of the utility. Many of these are traditional utility filings, while others will be non-standard agreements such as system operations and coordination with TEP upon initial operations.

An additional area of oversight includes North American Electric Reliability Corporation ("NERC") compliance requirements that would be triggered if the City required qualified transmission line ownership. A NERC Compliance Officer would be required assess compliance needs, coordinate registrations, document filing requirements, and develop and oversee a compliance plan. Failure to meet reliability standards may result in federally imposed sanctions or stiff penalties. The Tucson public power utility is interested in offers from interested parties to provide these resources and services.

Support Services

The Support Services function includes the City's traditional internal services, such as information technology and telecommunications, safety and environmental, facilities and fleet management, and human resources. Existing City staff will manage transitional work with full-time or part-time incremental staff hired for initial operations. The exception is the need for a human resources specialist to perform a staffing assessment early in the transition process. The Tucson public power utility's projected electric utility staffing level may be approximately 100 permanent and contract positions, with the majority requiring unique skill sets and knowledge. To prepare for efficient hiring, the Tucson public power utility may pre-define and approve position titles, responsibilities and pay grades. This will enable the Tucson public power utility to expedite the hiring process for key personnel and to select candidates with industry experience who can immediately contribute to the organization while minimizing training.

For the transitional period, Support Services may expand or adopt City of Tucson policies to include the needs of the electric utility. The most critical area is electrical safety, which is guided by the Occupational Safety and Health Administration and National Electrical Safety Code standards.

The Tucson public power utility must adopt safety standards in time to train contractors before any system work is performed and engage a Safety Compliance Officer trained in the unique safety standards for electric utilities. Additionally, Support Services will engage external consultants to assist with global inter-department needs assessments. The timely evaluation of IT systems must be prioritized to determine those that require expansion, development, and possible integration with TEP. Inter-department evaluations for customary items such as facility space, vehicles, standard software packages, phones, computers, radios, uniforms, and branded items must also be performed.

The Tucson public power utility is interested in offers from interested parties to provide these resources and services.