City of Arts & Innovation

# City Council Memorandum

**TO:** HONORABLE MAYOR AND CITY COUNCIL **DATE: MAY 14, 2024**

**FROM:** PUBLIC UTILITIES DEPARTMENT **WARDS: ALL**

**SUBJECT:** RIVERSIDE TRANSMISSION AND RELIABILITY PROJECT (RTRP)

## ISSUES:

Discuss status of the Riverside Transmission and Reliability Project (RTRP), consider options, and staff recommendations.

Options available for City Council consideration:

A. Proceed with the RTRP, as approved.

> The CPUC granted Southern California Edison (SCE) a Certificate of Public Convenience and Necessity for RTRP, authorizing SCE to construct RTRP as currently designed. Funding for the RTRP project was also approved for the portion of the project from Miraloma Substation (outside the City) to the new Wildlife Substation (in the City) in the amount of $521 million (City's portion is 1.7% of this total). In addition, it is anticipated that the City will incur $200 million to redesign and upgrade the City's electrical distribution system citywide. SCE currently has the authorization to proceed with the development of the RTRP without action by the City Council. According to SCE, RTRP would take four years to complete.

B. Initiate a new project.

> This option could include undergrounding all or a portion of transmission lines and would require communicating with approval agencies (i.e. California Public Utilities Commission, Federal Energy Commission) and SCE that the City Council would like prior approvals rescinded. Further, the City Council would need to provide direction to initiate a new project, prepare and submit new applications, environmental documents (i.e., EIR, studies, etc.), and other applicable materials. It is unknown how long it would take to secure approvals and funding for a new project; however, the current project took 16 years to obtain approval and collectively cost $721 million. If a new project were to be fully undergrounded, it is unknown whether the project costs would be higher, lower, or comparable to the current RTRP project costs.

C. Alternatively, the City Council could establish alternative options.

**RECOMMENDATIONS:**

That the City Council:

1. Receive an update regarding RTRP.

2. Direct staff to continue implementation of the City portion of the Riverside Transmission Reliability Project;

3. Direct Public Utilities Department staff to initiate a system capacity analysis and present findings and recommendations to the Board of Public Utilities to address short-term system capacity limitations in order to maintain safe, reliable and prudent operating standards; and

4. Direct the City Manager and City Attorney to request that Southern California Edison reinitiate, without delay, the complete construction and operation of their portion of the Riverside Transmission Reliability Project.

**BACKGROUND:**

Over the past 14 months, the City Council supported the formation of a working group to identify and secure funding sources for further undergrounding of the Riverside Transmission Reliability Project (RTRP). This effort highlighted issues, resulted in a thorough and robust debate, and reached the highest levels of review and consideration. In a letter dated October 31, 2023, the City Council requested that the California Public Utilities Commission, as part of their consideration of a Petition for Modification (PFM) submitted by the City of Norco, evaluate these issues and the option to underground the project while also highlighting the critical need for the project in the opening statements. The time spent was instructive and all options were exhausted to change the project.

At the April 16, 2024 City Council meeting, Councilmember Perry requested staff bring a specific recommendation to City Council on the status and any plans moving forward with RTRP. Further, he requested a discussion and decision in response to the most recent letter received from SCE (discussed later in this report).

Recent RTRP Timeline Highlights:

- November 15, 2022 – A majority of the City Council voted to proceed with RTRP as designed with overhead transmission lines. The City Council has not voted to change this position.

- January 17, 2023 - The City Council voted to form a working group consisting of federal, state, and local leaders to identify and secure funding sources for further undergrounding of Riverside Transmission Reliability Project. An update was provided to the City Council on June 27, 2023 and a final report was presented to the City Council on October 24, 2023.

- October 2, 2023 - The City of Norco (Norco) filed a Petition for Modification (PFM) at the CPUC requesting that the record be reopened to reconsider the full-undergrounding alternative for the RTRP.

- October 24, 2023 – The City Council voted to draft a letter concerning the City of Norco Petition for Modification submitted to the California Public Utilities Commission (CPUC) for full undergrounding of the RTRP.

- March 21, 2024 – The CPUC voted to deny the City of Norco's PFM to underground RTRP. The denial of Norco's PFM confirms the CPCN decision approved on March 18, 2020 authorizing SCE to construct the RTRP as designed at that time.

- March 22, 2024 - SCE's President and Chief Executive Officer, Steven D. Powell submitted a letter to the City. The letter, attached for reference, reaffirms SCE's commitment to complete the RTRP project in as timely a manner as possible. However, to ensure that California's ratepayers do not incur financial exposure should the project change mid-construction, SCE has requested that the City take action to "firm[ly] and unconditional[ly] support the [RTRP]."

- April 26, 2024 - Assembly member Bill Essayli amended AB 3076 on March 21, 2024 to specifically address the RTRP. The bill is identified as fiscal and is required to be referred to a fiscal committee before proceeding to the other house for consideration. This bill failed to receive a hearing in the Assembly Committee on Utilities and Energy, its only policy committee assignment, before the April 26, 2024 deadline for bills tagged as fiscal. As such, it will not move forward in the 2024 legislative session. The 2024 legislative session is the second year of the two-year legislative cycle and this bill cannot be a two-year bill.

*<u>Historical RTRP Timeline Highlights</u>*

- June 2006 – the California Independent System Operation (CAISO), which is the independent organization responsible for planning the statewide transmission grid, conducted studies concluding a need for the project.

- February 2013 – City Council certified the Final Environmental Impact Report (EIR).

- April 2015 – Southern California Edison (SCE) filed a Certificate of Public Convenience and Necessity (CPCN) application with the California Public Utilities Commission (CPUC) for approval to construct the project.

- January 2017 – Application deemed complete by the CPUC.

- 2018 - Supplemental EIR published by the CPUC for public review and subsequently approved in March 2020.

- March 2020 - The CPUC granted SCE a Certificate of Public Convenience and Necessity for RTRP, authorizing SCE to construct RTRP as currently designed. Funding for the RTRP project was also approved for the portion of the project from Miraloma Substation (outside the City) to the new Wildlife Substation (in the City) in the amount of $521 million (City's portion is 1.7% of this total). In addition, it is anticipated that the City will incur $200 million to redesign and upgrade the City's electrical distribution system citywide.

*<u>Overview</u>*

**The RTRP was designed and proposed to support a safe and reliable electric distribution system that will serve the City's existing customers and support additional growth within the City's limits.** The purpose and need for the RTRP have not changed since the project's inception. RPU's electricity loads are expected to exceed capacity standards for a safe and reliable electric grid as early as 2029 and potentially as early as 2026 should additional growth currently anticipated occur. The RTRP will provide an additional 560 MW of capacity and a much-needed second interconnection to the regional grid. The Riverside City Council approved the project with a certified environmental impact report (EIR) in 2013. The California Public Utilities Commission granted Southern California Edison (SCE) a Certificate of Public Convenience and Need (CPCN) and directed SCE to construct the project on March 18, 2020. With the recent denial of a Petition for Modification (PFM) that the City of Norco had filed, the project today is approved. The information presented in this background summarizes the extensive public record of information that explains the need and has comprehensively evaluated the project.

**Riverside's current distribution system capacity is supporting electricity demand that exceeds the prudent operating standards and practices of the electric utility industry to maintain a safe and reliable electric system.** Under these standards, it is recommended that utilities have infrastructure that will support peak electric loads in an expected operating condition that includes the loss of one key component of the infrastructure system.

In 2022, Riverside Public Utilities (RPU) load almost exceeded the maximum safe planning capacity of 657 megawatts (MW) when the peak load reached 648 MW. RPU's total system capacity includes internal generation and the capacity to import electricity through a single interconnection to the regional grid at the Vista substation. This combination of infrastructure provides a maximum capacity of 754 MW of electricity to serve the City. However, when considering safety and reliability standards to operate the distribution system in the City, the loss of either a bank of transformers that support RPU's Riverside Energy Resource Center (RERC) power plant (loss of 97 MW of capacity) or the loss of a transformer bank at the Vista substation (loss of 280 MW of capacity) would reduce the capacity RPU can serve to 657 MW or 474 MW, respectively.

**Table 1. Forecast Peak Loads Compared to RPU System Capacity for N-1 Condition is 657 MW**

*Normal Capacity Less the Loss of One Critical Infrastructure Component: Loss of a transformer serving RERC (754 MW – 97 MW = 657 MW) with Load Growth Assumed at Averages for Last Few Years*

| | Forecast Load For Weather/Temperature Scenarios | | | |
|---|---|---|---|---|
| **Year** | **1-in-2** | **1-in-5** | **1-in-10** | **1-in-20** |
| 2024 | 598.4 | 628.4 | 644.4 | 657.4 |
| 2025 | 600.7 | 630.7 | 646.7 | 659.7 |
| 2026 | 603.3 | 633.3 | 649.3 | 662.3 |
| 2027 | 606.2 | 636.2 | 652.2 | 665.2 |
| 2028 | 609.2 | 639.2 | 655.2 | 668.2 |
| 2029 | 612.5 | 642.5 | **658.5** | 671.5 |
| 2030 | 616.0 | 646.0 | **662.0** | 675.0 |
| 2031 | 619.8 | 649.8 | **665.8** | 678.8 |
| 2032 | 623.9 | 653.9 | **669.9** | 682.9 |
| 2033 | 628.1 | 658.1 | **674.1** | 687.1 |
| 2034 | 632.6 | 662.6 | **678.6** | 691.6 |
| 2035 | 637.3 | 667.3 | **683.3** | 696.3 |
| 2036 | 642.3 | 672.3 | **688.3** | 701.3 |
| 2037 | 647.5 | 677.5 | **693.5** | 706.5 |
| 2038 | 652.9 | 682.9 | **698.9** | 711.9 |
| 2039 | 658.6 | 688.6 | **704.6** | 717.6 |

Note: Shaded cells indicate forecast load exceeding the prudent operating capacity standard for an Expected System Condition

RPU forecasts its expected loads under various weather conditions. Peak loads are forecast for temperature conditions of a 1-in-2, 1-in-5, 1-in-10, and 1-in-20-year weather event, <u>all of which have been experienced in the last 5 years</u>. System and equipment are typically planned and designed to accommodate the 1-in-10 weather event. Table 1 shows the forecast peak loads for these potential temperature conditions prepared and reported to the California Energy Commission for its Integrated Energy Policy Report in 2023. Highlighted cells indicate conditions that will cause electricity load to exceed the N-1 system capacity standards for a safe and reliable electric system. **Under the 1-in-10 temperature forecast, the City's electric**

**loads will exceed the safe operating capacity by 2029.**

This forecast load growth does not yet include several development projects that are currently in either a planning or development stage within the City. If load growth anticipated due to these additional developments comes to fruition in the next few years and electric vehicle and building electrification is accelerated as anticipated due to State regulation, peak loads will exceed 657 MW as early as 2026 under normal planning standards. Adding these peak loads that were not incorporated into RPU's current load forecasts shows that RPU would experience capacity exceedance even earlier than the dates shown in Table 1.

**Table 2. Forecast Peak Loads With Additional Growth Compared to RPU System Capacity for N-1 Condition is 657 MW**

*Normal Capacity Less the Loss of One Critical Infrastructure Component: Loss of a transformer serving RERC (754 MW – 97 MW = 657 MW) (754 MW – 97 MW = 657 MW) with Load Growth Assumed to Accelerate to Accommodate Significant New Growth*

| | Forecast Load For Weather/Temperature Scenarios | | | |
|---|---|---|---|---|
| **Year** | **1-in-2** | **1-in-5** | **1-in-10** | **1-in-20** |
| 2024 | 601.4 | 631.4 | 647.4 | 660.4 |
| 2025 | 611.3 | 641.3 | 657.3 | 670.3 |
| 2026 | 623.1 | 653.1 | **669.1** | 682.1 |
| 2027 | 634.4 | 664.4 | **680.4** | 693.4 |
| 2028 | 645.8 | 675.8 | **691.8** | 704.8 |
| 2029 | 661.1 | 691.1 | **707.1** | 720.1 |
| 2030 | 667.6 | 697.6 | **713.6** | 726.6 |
| 2031 | 679.4 | 709.4 | **725.4** | 738.4 |
| 2032 | 691.5 | 721.5 | **737.5** | 750.5 |
| 2033 | 703.7 | 733.7 | **749.7** | 762.7 |
| 2034 | 716.2 | 746.2 | **762.2** | 775.2 |
| 2035 | 728.9 | 758.9 | **774.9** | 787.9 |
| 2036 | 741.9 | 771.9 | **787.9** | 800.9 |
| 2037 | 755.1 | 785.1 | **801.1** | 814.1 |
| 2038 | 768.5 | 798.5 | **814.5** | 827.5 |
| 2039 | 782.2 | 812.2 | **828.2** | 841.2 |
| 2040 | 601.4 | 631.4 | **647.4** | 660.4 |

Note: Shaded cells indicate forecast load exceeding the prudent operating capacity standard for an Expected System Condition

*<u>Consequences of Loads Exceeding Capacity</u>*

**When electricity loads exceed system capacity, RPU must undertake load shedding through rolling blackouts.** RPU's loads are highest (peak) in the summer when temperatures are hottest, and customers use electricity (air conditioning) to keep their buildings cool. Load shedding is the intentional, controlled interruption of electrical load to protect most of the electric system from permanent damage that an overload could cause. Areas of the City will experience electrical blackouts. RPU's current operating procedures call for rolling blackouts, for which multiple city areas will experience one-hour outages that will rotate every hour until the load subsides to a safe operating status. Continuing to serve loads beyond system and equipment capacities leads to equipment failure (and a loss of capacity until the equipment can be repaired or replaced, usually at a high cost).

**Because the potential for load shedding is increasing, continuing to approve development projects without remediation to address peak load issues is of concern.** To accomplish this, RPU would be required to either limit capacity growth (develop a capacity reservation system) or place requirements on development that will require them to mediate their load additions until RPU has the capacity to serve them.

***<u>Need for the RTRP</u>***

**As the electric utility serving the City of Riverside, RPU and the City must provide a safe and reliable energy supply and electrical infrastructure to all customers, including government, education, and health facilities within the City limits.** SCE has the exact requirements for all customers within its territory, and the CPUC oversees its actions. The need and all options and impacts of the RTRP are well documented in the extensive public record, which includes two environmental impact reports, testimony before the California Public Utilities Commission, numerous studies, and technical evaluations. Readers are strongly encouraged to refer to these documents for detailed information. The need for the RTRP was noted in the City Council's letter to the California Public Utilities Commission (CPUC) dated October 31, 2023, submitted as part of the proceedings related to the City of Norco's Petition for Modification of the RTRP.

In order to meet this obligation, RTRP was developed to address two reliability objectives:

1. Safe and reliable electric system and source of electricity for existing and forecast customer electricity demand, and
2. Provide an additional source of electricity from the statewide power grid.

As the City has grown due to new customers and developments, and because customers are using more electricity by adding electric appliances, vehicles, and other uses, the load demands for RPU's service have increased over time. Furthermore, increased load demands are expected to continue as the City strives to expand development and transition away from fossil fuels. Most importantly, however, RTRP is intended to provide reliable electric service to ensure the safety of the City of Riverside's communities, businesses, and services. Electricity is needed for almost all aspects of life, including lighting, cooking, business operations, traffic lights, communications systems, medical devices, and residential and commercial air conditioning. Additionally, as the City and the community transition away from the use of natural gas and other fossil fuels for transportation and building heating and cooking uses over the next ten years (primarily in response to State mandates that are changing what vehicles and appliances will be available), the existing and future community will need a reliable and safe electric system to support them in their everyday lives. A second point of interconnection is critically necessary to support this anticipated load growth and these state electrification initiatives.

The need for reliable access to the regional grid, as well as the development of internal resiliency on the distribution system, was demonstrated in October 2007 when all 69 kV sub-transmission lines connecting the City to SCE's Vista Substation were interrupted (see discussion in City of Riverside, FEIR, October 2012). In that event, all electric utility customers in the City were without power for up to four hours – including residents, government, schools, universities, and hospital emergency facilities. The outage also affected telecommunications, the cellular network, traffic signals, and street lighting. Medical facilities, government, and other services had to use backup power generation to continue operations. This demonstrated the need to develop additional internal generation resources that could be used to support these essential functions as well as the need to expedite the development of a second interconnection to the regional power grid.

The City of Riverside is connected to the regional power grid through one point of interconnection at SCE's Vista Substation. RPU has contracts with several generation facilities throughout the western United States, particularly California. Electricity serving customers is primarily brought in through the Vista Substation's two transformer banks that deliver electricity into the City along seven 69 kV lines. Riverside can receive up to 560 megawatts (MW) of electricity through this infrastructure. In the early 2000s, the City recognized a need for additional access to the regional grid to provide reliable electricity to the City's customers. During summer peak heat events, electricity demand was increasing and was expected to exceed the capacity at the Vista Substation.

When electricity demand exceeds the capacity of the infrastructure, RPU needs to institute a load-shedding protocol to some portion of the grid to maintain the stability of the overall distribution system. Under this protocol, one or more circuits would be turned off to keep the overall customer demand below the amount that can be brought into the City. To avoid the need to implement power outages during these summer events, the City initiated a two-pronged approach:

1. Construct internal generation to support customer electricity needs during summer peak events and,
2. Initiate efforts to develop a second interconnection to the regional power grid.

The City first constructed and built the Springs Power Generation facility (Springs) in 2002. Springs consist of four peaking turbines, each providing up to 9 MW of electricity to support electricity demand in the summer peak hours. This provided an additional 36 MW of capacity to RPU's distribution system. The City also immediately began the work to construct the Riverside Energy Resource Center (RERC) to provide more time to develop the second transmission interconnection. RERC comprises four turbines, each providing up to 48.5 MW of electricity generation in peak operating conditions. RERC units 1 and 2 came online in 2006, and units 3 and 4 came online in 2011. RERC added 194 MW of capacity to the RPU distribution system. Both facilities were intended to be operated in a limited capacity to allow time for the second interconnection to be built. Springs is anticipated to reach the end of its operational life in 2027, while RERC's units should be able to operate through 2039.

The Springs and the RERC facilities use natural gas combustion to generate electricity. As peaking facilities, they are typically intended to support the hours of the year when Riverside's loads reach their highest levels. For Riverside, this occurs during summer heat waves when air conditioning loads are highest. Both Springs and RERC have limitations on their operation because of the emissions resulting from the combustion of natural gas.

Two issues further limit Springs. First, the Springs units are less efficient and, as a result, produce fewer MWs for the amount of natural gas combusted, making them more expensive to operate. Second, the Springs units have reached end-of-life. Replacement parts for many of the critical components for the Spring units are no longer manufactured, nor are they available to purchase (used or new). As such, the Springs generation units should not be considered a reliable facility for capacity analysis.

*RPU's Current System Status*

Based on the limitations at Springs, RPU's total system capacity is comprised of the amount of capacity provided at the Vista Substation and the summer operational capacity at the RERC units. Summarized below, RPU's total system capacity is 754 MWs.

| | |
|---|---|
| Capacity at Vista | 560 MW |
| Summer Generation RERC Unit 1 | 48.5 MW |
| Summer Generation RERC Unit 2 | 48.5 MW |
| Summer Generation RERC Unit 3 | 48.5 MW |
| Summer Generation RERC Unit 4 | 48.5 MW |
| Total Capacity on RPU Distribution System | 754 MW |

Growth in summer peak loads has occurred. The total number and duration of peak load events has increased in frequency. The City's summer peak loads for the last 14 years have exceeded the import capacity of 560 Megawatts (MW) provided through the Vista substation. In fact, in 2022, RPU's summer peak reached 648 MW – almost 90 MW more than the capacity provided at RPU's single interconnection through the Vista Substation.

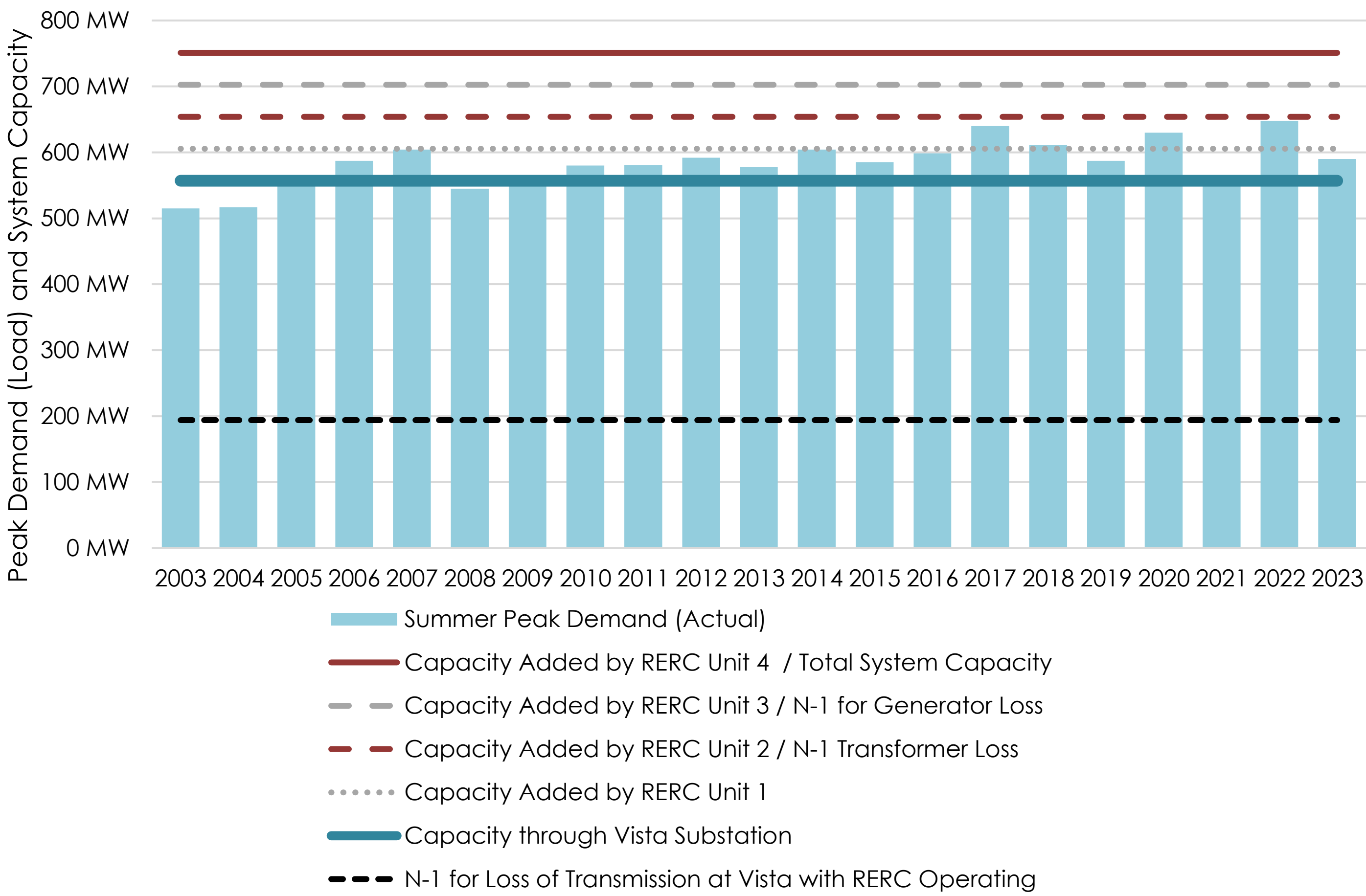
While it may seem that RPU continues to have a safe operating capacity during summer events with a capacity of about 100 MW greater than the highest summer peak, prudent utility planning calls for sufficient physical facilities to serve customers reliably under "expected conditions." A normal condition is when all infrastructure is functioning. "Expected conditions" include the loss of a single critical point in the infrastructure system that impacts the ability to serve load and requires the shift of that load to other system infrastructure. Expected conditions include the loss of a power generation facility, a transformer, or a transmission line. Each of these normal minus one critical point of failure in the system is also referred to as an N-1 condition. Utilities typically plan and maintain redundancy in their systems to accommodate an N-1 condition. In such a situation, the utility can continue to provide customers with electricity safely and reliably. (In critical areas of a city, such as medical facilities, downtown areas, and areas with elevators, and in critical economic centers, utilities often plan for an N-2.) The following table identifies the prudent utility planning system capacities for the three types of N-1 conditions that RPU and the City should be planning for.

**Table 3: Normal minus One (N-1) Capacity Standards for RPU**

| N-1 Condition | Total Remaining Capacity |
|---|---|
| **Loss of Transmission (already surpassed)** | |
| Loss of one of two transformers at Vista (loss of 280 MW capacity) | 754 MW – 280 MW = **474 MW**<br>RPU Summer Peak exceeds this capacity |
| **Loss of a Generation Asset** | |
| Loss of 1 RERC unit (loss of 48.5 MW capacity) | 754 MW – 48.5 MW = **705.5 MW** |
| **Loss of a Critical Infrastructure Transformer** | |
| Transformer loss in equipment connecting RERC units to the distribution system would result in the loss of generation from two RERC units (loss of 97 MW capacity) | 754 MW – 97 MW = **657 MW**<br>RPU Summer Peak almost exceeded this capacity |
| *Note: The loss of both transformers at the Vista substation (loss of 560 MW capacity) would be what is considered an N-2 condition. RPU would only be able to serve 194 MW of load.* | |

As stated previously, if demand or load exceeds the system capacity, rolling blackouts (or forced outages) would need to be implemented to ensure system stability. Loss of transmission through all or a portion of the Vista Substation (560 MW) would result in systemwide power outages for RPU customers because the RERC units would not provide sufficient generation to support the overall system load. Emergency services such as hospitals and emergency centers would be prioritized for receiving power. RPU's customers would only receive power from RERC (194 MW) plus any available capacity at Vista. Capacity limits under the loss of one of the RERC units would be 705.5 MW (754 MW total system capacity – 48.5 MW generation capacity of one RERC unit). Finally, in the event of the loss of a transformer serving the RERC generation units, the N-1 capacity is 657 MW (754 MW total system capacity – 97 MW generation capacity for two RERC units) – a mere 6 MW greater than RPU's highest recent system peak load of 648 MW.

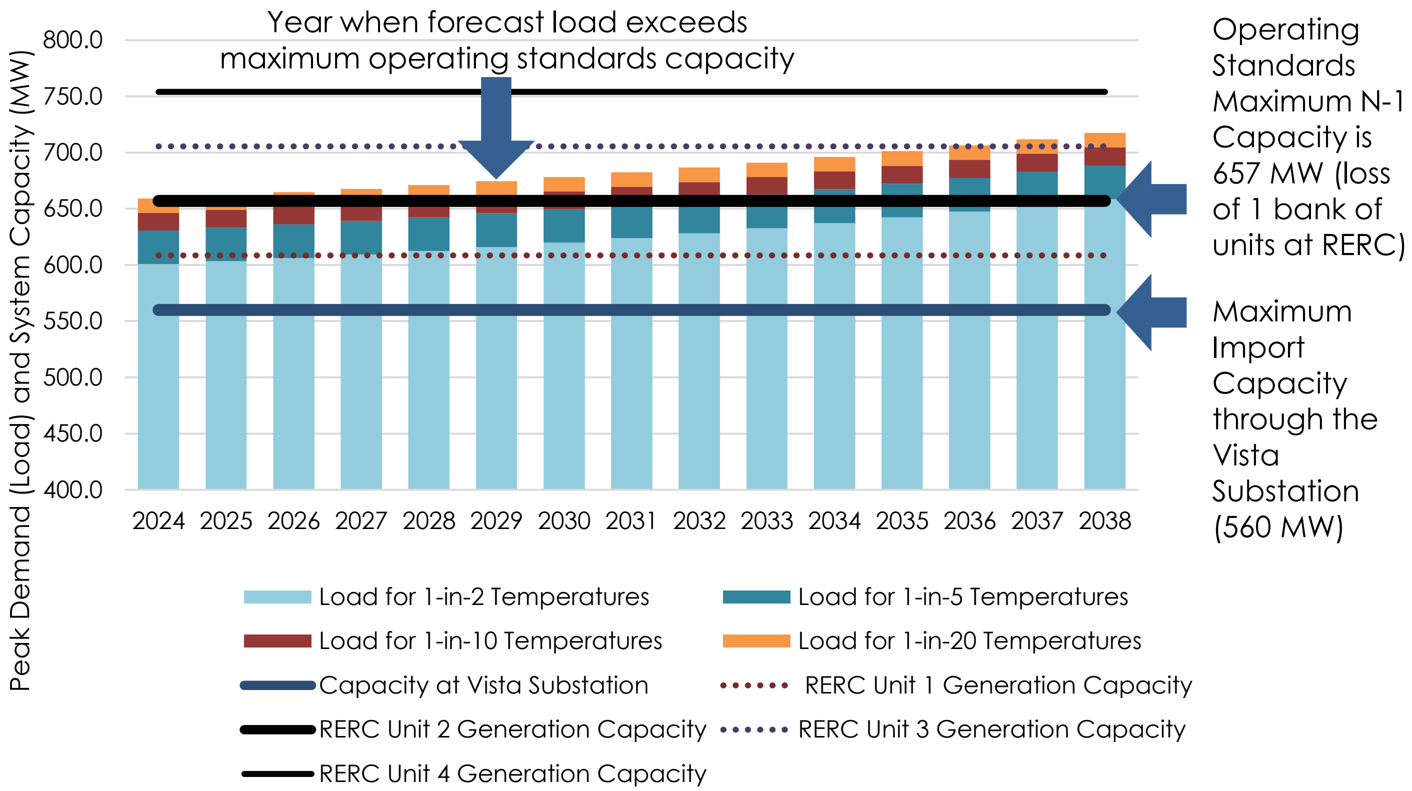
**Figure 1. System Capacity Compared to Actual Peak Load (2003 to 2023)**




It is important to note that these risks are not necessarily year-round. Only the loss of both Vista transformers has the potential to result in load-shedding events if they occur at any time of the year. All other N-1 conditions primarily occur during summer peak loads. Should an N-1 condition occur, load shedding would be necessary to keep loads at acceptable operating levels during heat events. RPU staff works diligently to keep all equipment and infrastructure operating in top condition in preparation for these summer events. However, it is essential to plan for and develop the infrastructure needed to address these N-1 scenarios to maintain the safety of the system and the community.

Under forecasted load conditions, peak loads are expected to continue to exceed the capacity under N-1 conditions.

**Figure 2: System Capacity Compared to Forecast Peak Load**




<u>*Description of the RTRP*</u>

The Southern California Edison (SCE) project, as approved by the California Public Utilities Commission (CPUC), is the design, construction, and operation of a high-voltage transmission line to supply reliable electric service to the City of Riverside (Riverside) through a new second connection to the state bulk electric system grid. The Riverside Transmission and Reliability Project (RTRP) consists of the construction of 10 miles of 230,000 volt (230kV) double circuit transmission line (approximately 4 miles underground, 6 miles above ground) and a new 230kV substation and associated facilities needed by SCE to operate the facilities. All the transmission lines initially proposed in the Environmental Impact Report (EIR), which Riverside had prepared and approved, were to be installed using above-ground construction. The original project was redefined as the "revised project" to settle a legal challenge from property developers in Jurupa Valley along the proposed route. The revised project proposed undergrounding two miles of transmission line within 68th Street heading north on Pats Ranch Road. No legal challenges to modify the project design for the portion of the project south of the Santa Ana River in the City of Riverside were made at that time.

An "Alternative 1" project proposal was later developed in response to directives by the CPUC to consider further project alternatives and mitigate known significant environmental impacts. The result was the Alternative 1 project, which proposed undergrounding an additional 2.1 miles of transmission lines in Jurupa Valley. This modification created an underground transmission line at Cantu-Galleano Ranch Road near (SCE Mira Loma Substation) to a location before extending across the Santa Ana River. CPUC deemed Alternative 1 as the environmentally superior alternative, reducing "RTRP's impacts on aesthetics and agricultural and forestry resources" in response to the project's legal opponents.

*Approval to Construct the Project - Certificate of Public Convenience and Necessity*

On March 18, 2020, the CPUC, as the regulatory agency, granted SCE a Certificate of Public Convenience and Necessity (CPCN) for the Riverside Transmission and Reliability Project. Additionally, the CPCN authorizes SCE to construct RTRP as currently designed; the CPUC determined the Subsequent Environmental Impact Report (SEIR) was completed in compliance with the California Environmental Quality Act (CEQA), that the total maximum project cost of the project not exceed $521 million, and required any changes in project scope and schedule greater than a project refinement (inside the geographic boundary of the EIR study area, no new significant impact or substantial increase in the severity of a previously identified significant impact) be subject to a petition to modify application by SCE to the CPUC.

This 40-page document is extremely useful for understanding the CPUC's reasoning for ordering the project to be constructed. It identifies the clear need that the City of Riverside and its customers have for a second point of interconnection for bulk power transmission. **It identifies Riverside as the only electric utility in California with a single point of connection to the state bulk transmission system that is served by transmission lines below 230,000 volts (230 kV) and recognized the significant outages at the SCE Vista Substation in 2005 and 2007.** The CPUC weighed the environmental impacts of the project based on the testimony and documents submitted into the legal record and determined **that Riverside's needs "are overriding considerations that serve the public convenience and necessity and outweigh the project's unavoidable impacts** on aesthetics, agricultural and forestry resources, noise and transportation and traffic, and its significant contribution to cumulative hydrology and water quality impacts."

*Interconnection Facilities Agreement with SCE*

Riverside and SCE are parties to an Interconnection Facilities Agreement (IFA) that provides for SCE to engineer, design, construct, install, own, operate, and maintain the RTRP. The current version of the IFA is dated as of January 15, 2019, and is the third such amended agreement. SCE and Riverside initially signed a letter of agreement setting forth initial terms and conditions for developing the RTRP on April 11, 2006. They entered into the original IFA on March 9, 2009. The 2009 IFA was subsequently amended through the first and second amendments dated August 10, 2010, and March 23, 2018. The IFA sets forth various rights and obligations of SCE and Riverside in connection with the development, ownership, and operation of the RTRP. Because the RTRP remains in the development phase, the summary and analysis provided below will focus primarily on the IFA's provisions that address pre-operational terms and conditions, including contingencies if the RTRP is cancelled or abandoned.

As discussed in more detail below, the IFA includes specific terms providing cost allocation to RPU if RPU terminates the IFA or other circumstances arise, including those that may allow SCE to terminate the IFA.

1. Regulatory Background

Because SCE is a "public utility" under the Federal Power Act (FPA),[1] the IFA has been filed with and approved by the Federal Energy Regulatory Commission (FERC). Under the FPA, FERC has jurisdiction over the rates, terms, and conditions of (i) wholesale power sales in interstate commerce by public utilities and (ii) electric transmission services by public utilities.[2] The IFA addresses interconnection, which is a form of transmission service. Under the FPA, the rates, terms, and conditions of jurisdictional services must be "just and reasonable" and non-discriminatory.[3] As an agreement subject to FERC's regulatory oversight, FERC regulations and policy are applicable to the IFA, which cannot be revised or terminated without FERC's authorization. The IFA, in Section 19.1, specifies the rights of each party to petition FERC to change the agreement. FERC would assess the merits of such a petition under the legal standard in the FPA—*i.e.*, whether the proposed change is just and reasonable and non-discriminatory—with the proponent of the change bearing the burden of proof.

2. IFA Development Obligations and Terms

In addition to SCE's obligations to build, own, and operate the RTRP, the IFA includes other rights and obligations of SCE and Riverside in connection with the project's development.

*a) Facilities and Cost Allocation*

The IFA includes a detailed overview of the facilities comprising the RTRP and classifies them as either "ISO Controlled Facilities" or "Interconnection Facilities." The cost of each type of facility is allocated differently in the IFA and consistent with FERC policy. Definitions of these facilities are provided in Section 4 of the IFA, with detailed descriptions of the ownership delineations provided in Sections 8.2 through 8.7 and in Exhibits A, D, and E.

The ISO Controlled Facilities of the RTRP, which will be owned by SCE, include (i) most of the facilities and equipment in the Wildlife Substation; (ii) the Mira Loma-Vista 220 kV Line Loop; and (iii) associated upgrades at SCE's Mira Loma and Vista Substations. When the ISO Controlled Facilities enter service, they will function as part of the integrated, statewide transmission network. Because these networked facilities are capable of being used to provide services on the CAISO-controlled grid, they will be placed under the operational control of the CAISO, and their costs are eligible to be recovered from CAISO transmission customers (of which Riverside is one) through the CAISO's access charge rates. This cost allocation is aligned with FERC policy, which provides for the cost of integrated, networked transmission facilities to be "rolled in" or allocated to all customers that use the transmission system.[4]

The Interconnection Facilities include specific equipment within the SCE Wildlife Substation that will be used to enable the physical connection of the SCE and Riverside electric systems via Riverside's new Wilderness Substation, which is where Riverside will receive power from the CAISO-controlled grid via the Mira Loma-Vista 220 kV Line Loop and the Wildlife Substation. Interconnection facilities are sole-use facilities by Riverside, and Riverside directly assigns their cost.

*b) Development Responsibilities*

As noted, the IFA states that SCE will design, engineer, procure, construct, install, own, operate, and maintain the Wildlife Substation and the Mira Loma-Vista 220 kV Line Loop (*see* § 8.1), while Riverside is to perform these same activities with respect to the Wilderness Substation (*see* § 8.5). To enable Riverside and SCE to develop their respective portions of the RTRP, the IFA provides (at § 8.8) for Riverside to act as the lead CEQA agency, including for the ISO Controlled Facilities. SCE was assigned responsibility for obtaining regulatory approvals for the Wildlife Substation and the Mira Loma-Vista 220 kV Line Loop (*see* § 8.1), while Riverside was assigned responsibility for acquiring permits and approvals for the Wilderness Substation (*see* §§ 8.5, 8.8). However, the parties agreed to provide information and assistance to one another in securing necessary permits and regulatory approvals (*see* § 8.8). Each party's respective development responsibilities are subject to the standards of "good utility practice" and the use of "commercially reasonable efforts" to meet estimated timelines under Sections 8.15 and 8.16. The parties also agreed under the same provisions to mutually cooperate to advance the in-service dates of the RTRP.

Riverside also agreed in the IFA to provide certain easements, described in Section 8.14 of the IFA and to sell land to SCE for the Wildlife Substation pursuant to Section 13.

*c) Payment Structure*

The payment structure in the IFA for the development of the RTRP, described in IFA Sections 14.4 through 14.6, provides for Riverside to have funded SCE's development costs for the RTRP, including engineering and design activities, right-of-way studies, environmental support, permitting, and other activities necessary for the construction of both the SCE Wildlife Substation and the Mira Loma-Vista Line Loop until the point at which the project is approved by the CAISO (which approval occurred in 2006) and permitted by the CPUC via issuance of a CPCN (which occurred in 2020). Once these conditions were met, SCE assumed responsibility for funding the development of these facilities and repaid Riverside the monies that it had advanced to fund SCE's development work. This funding structure ensured that the development risk was assigned to Riverside up to the point at which both the CAISO and the CPUC authorized SCE to move forward with the RTRP.

Although the IFA provides for SCE to assume the costs of developing the RTRP after both the CAISO and the CPUC have approved the project, such costs can be reallocated to Riverside in the event of termination of the IFA.

Section 5.2 permits Riverside to terminate the IFA upon notice. However, Riverside is obligated to repay SCE for costs incurred or irrevocably committed to be incurred for the SCE Interconnection Facilities, and if Riverside terminates the IFA before SCE's Wildlife Substation enters service, Riverside is also obligated for costs incurred or irrevocably committed to be incurred for the ISO Controlled Facilities:

> 5.5 Following termination of this Agreement, Riverside shall pay SCE any remaining balance owed for SCE's costs incurred or irrevocably committed to be incurred as of the termination date (and subsequently paid by SCE) pursuant to this Agreement for the SCE Interconnection Facilities.… If this Agreement is terminated before the Wildlife Substation In-Service Date, Riverside shall also pay SCE for SCE's costs incurred or irrevocably committed to be incurred as of the termination date (and subsequently paid by SCE) for the ISO Controlled Facilities.…

Additionally, Section 14.7 of the IFA requires Riverside to reimburse SCE for the costs incurred for both the SCE Interconnection Facilities and the ISO Controlled Facilities if the IFA is terminated and certain conditions are met:

> Riverside shall reimburse SCE for all costs incurred by SCE, including any costs reimbursed to Riverside pursuant to Sections 14.5 and 14.6, for the design, engineering, permitting and regulatory, construction and installation of Wildlife Substation and the Mira Loma-Vista 200 kV Line Loop in the event that (i) this Agreement is terminated prior to the date the Riverside Wilderness Substation is physically interconnected to Wildlife Substation and energized; (ii) Riverside terminates its plan to complete construction and installation of the Riverside Wilderness Substation; (iii) Riverside does not complete construction and installation of the Riverside

> Wilderness Substation within one (1) year following the Wildlife Substation In-Service Date, unless such delay is due to an Uncontrollable Force event or the delay is agreed to by SCE in writing; or (iv) Riverside alters its interconnection request or changes the project and facilities description as originally specified in Riverside's 220 kV interconnection request dated December 20, 2004, such that Wildlife Substation and the Mira Loma-Vista 220 kV Line Loop are no longer required. If such events in this Section 14.7(ii), (iii), or (iv) above occur, SCE shall have the right to terminate this Agreement subject to FERC acceptance and approval.

The IFA is also terminable by SCE if the land sale under Section 13.2 does not take place (it has) or for nonpayment by Riverside of amounts owed to SCE (*see* § 15.4).

3. FERC Incentive Ratemaking Order

After the CPUC's issuance of the CPCN, SCE filed a petition for a declaratory order at FERC seeking authorization to implement specific incentive ratemaking treatments, including recovery of 100% of SCE's "abandoned plant costs" for the RTRP if the RTRP is cancelled or abandoned for reasons outside of SCE's control.[5] Incentive ratemaking treatments, including the abandoned plant incentive, are available under FERC policy for transmission projects that involve a heightened level of development risk. In its petition, SCE emphasized risks associated with obtaining permits, land rights, easements for the project, and risks associated with undergrounding transmission lines. SCE also cited the project's high cost, including the costs associated with undergrounding, and risks that Riverside might cancel or abandon its plans to construct the Wilderness Substation and "be insolvent or otherwise unable to fully reimburse SCE for its actual costs expended (or irrevocably committed to be expended), leaving SCE unable to collect these costs despite the terms of the IFA."[6]

FERC granted SCE's request for the abandoned plant incentive (and a second ratemaking incentive permitting SCE to include certain costs in its rate base during construction of the RTRP). It also ruled that the RTRP would constitute networked transmission facilities eligible for cost recovery through SCE's revenue requirement, which is included in the CAISO's access charge rates.[7] If the RTRP is cancelled or abandoned for reasons outside of SCE's control, then SCE is permitted to recover 100% of its project costs incurred from the date of the FERC order forward through its revenue requirement (and, thereby, the CAISO's access charges) which SCE's transmission customers pay.[8] For costs incurred before the date of the order, SCE is permitted to recover 50% of project costs in rates.[9] To implement this incentive, SCE would need to demonstrate that the project was abandoned for reasons outside of SCE's control and that its expenditures were prudently incurred.

4. Cost Recovery in the Event of IFA Termination

Although SCE has received authorization from FERC to recoup its costs to develop the RTRP through its revenue requirement if the project is cancelled, the provisions of the IFA that permit SCE to seek recovery of these exact costs from Riverside under specified conditions remain effective. If Riverside exercises discretion to terminate the IFA or the conditions in Section 14.7 occur. SCE may exercise its rights to obtain cost recovery from Riverside for both the SCE Interconnection Facilities and the ISO Controlled Facilities before seeking to recover its abandoned plant costs via the CAISO's access charge rates. For example, SCE's petition to FERC, in which it requested the abandoned plant incentive, suggested that it may require the incentive to address the contingency that abandonment costs are not recoverable from

Riverside. Parties representing other CAISO transmission customers may likewise argue that, even though SCE can recover abandoned plant costs through its access charge rates, the provisions of the IFA permitting recovery of these costs solely from Riverside should supersede CAISO-wide cost allocation. Although the IFA includes (at § 19.3) language recognizing alternative cost allocations, this language does not prohibit SCE from relying on cost recovery provisions in the IFA:

> The Parties each recognize that regulatory or legislative cost recovery mechanisms may result in a Party recovering all or a part of their costs in connection herewith from others, and nothing contained herein shall require a Party to forego the application of any such cost recovery mechanism(s), or alter any Party's responsibility for costs approved for recovery under any such mechanism(s).

Ultimately, FERC will determine the allocation of RTRP development costs if the IFA is terminated. FERC would weigh the provisions of the IFA against its order permitting SCE to recoup cancelled plant costs through its revenue requirement and evaluate the facts and circumstances resulting in abandonment of the RTRP to determine a just and reasonable cost allocation. While SCE has an avenue for cost recovery of 100% of its RTRP development costs from September 17, 2020 (the date of its order granting the abandoned plant incentive) forward and for 50% of its costs before the date of the order, SCE and CAISO transmission customers may assert that a discretionary decision by Riverside to terminate the IFA should result in cost allocation to Riverside under the IFA's terms.

[1] 16 U.S.C. § 824(e).
[2] 16 U.S.C. §§ 824(a), (b).
[4] *See City of Anaheim, Cal.*, Opinion No. 483, 113 FERC ¶ 61,091 at PP 27, 34, 47, 57-58 (2005); *order on reh'g*, Opinion No. 483-A, 114 FERC ¶ 61,311, at PP 13-14 (2006).
[5] Pet'n of S. Cal. Edison Co. for Decl. Order, *S. Cal. Edison Co.*, Docket No. EL20-51-000 (filed Jun 1, 2020).
[6] SCE Pet'n at 15-16.
[7] *S. Cal. Edison Co.*, 172 FERC ¶ 61,241 at PP 26, 31, 36 (2020).
[8] *Id*. at P 27.
[9] *Id*.

*Denial of the Recent City of Norco Petition for Modification*

On October 2, 2023, the City of Norco (Norco) filed a Petition for Modification (PFM) at the CPUC requesting that the record be reopened to reconsider the full-undergrounding alternative for the RTRP (Alternative 8 in the SEIR). The PFM asserted that multiple circumstances within the last two years significantly increased the risk of wildfire in the overhead portion of the RTRP route. On March 21, 2024, the CPUC denied the PFM. The CPUC stated that there was insufficient justification for why the PFM was filed three years after the Commission's issuance of the CPCN and that the PFM did not provide sufficient justification for why it could not have been filed within one year of the CPCN decision. Further, the final decision also noted insufficient justification for the CPUC to revisit the previously evaluated and discussed Alternative 8. Alternative 8 had been eliminated from consideration during the SEIR process because it would result in substantially more significant environmental impacts than the selected alternative. Additionally, the CPUC Decision (attached for reference) on the PFM also noted that the evaluation of the concerns expressed in Norco's application relating to wildfire and socio-economic impacts had been thoroughly evaluated and addressed in the proceedings leading to the CPUC's issuance of the CPCN in March 2020.

Following the vote, CPUC Commissioner Douglas provided the following comments regarding the decision:

- The petition was filed several years after the period to raise an issue. However, in keeping with protocol for petitions filed late, the applicant must justify the reason for a late petition. She reiterated that Norco did not meet that burden.
- Commissioner Douglas shared that the concerns raised were fully evaluated as all were considered by City of Riverside's certified EIR and supplemental EIR.
- The CPUC decision addresses the purpose of the project, which is to provide adequate transmission capacity and long-term system growth for future development.
- The CAISO approved the RTRP as necessary to meet Riverside's needs and directed SCE to build it and determined that the project was needed.
- The CPUC's decision points out that the wildfire issue raised in the position poses a less than significant risk as determined the City of Riverside's EIRs. The project will cross vegetation, and does present fire risk; however, Federal Law (section 4293) would reduce the likelihood of fire risk, given it prescribes the development and enforcement of fire management plan mitigation measures. The system will be designed to sustain high winds, includes a shutoff capability in a fraction of seconds and inspections will help to identify loose fittings, erosion and other mechanical areas.
- CPUC works closely with the Office of Infrastructure & Safety to ensure wildfire plans require extensive mitigation.
- The environmental review has already been carried out and was relied on and the record was considered when considering the issues in the CPUC decision.

**The denial of Norco's PFM confirms the CPCN decision approved on March 18, 2020, authorizing SCE to construct the RTRP as designed at that time.**

## DISCUSSION

Due to the system capacity limitations that the City of Riverside currently faces, RTRP should move forward in a timely manner. **If any options other than immediate support to move the RTRP forward are to be considered, RPU must plan to reduce and manage peak loads.**

*RPU's Electric Distribution System – Status and Potential Impacts*

Considering the status of the RPU distribution system capacity, the delays experienced in the construction of the RTRP, and prudent reliability standards, RPU staff recommends that the City Council direct RPU to initiate an evaluation of system capacity needs and options to accommodate existing and planned demand and peak load growth until the RTRP is constructed. RPU staff will present proposed options to the RPU Board for consideration of the costs in addition to any recommended or preferred actions that RPU should undertake.

With the continued changes requiring electrification of transportation and electric systems and the economic and housing growth envisioned in the City's General Plan and Housing Elements, Riverside's peak load and overall energy consumption are forecast to grow. The need to transition to 100% carbon-neutral electricity for retail load by 2045 must also be considered due to the impacts this will have on RPU's natural gas-fired generation. Electricity demand exceeding the capacity provided by the Vista substation is expected to continue and worsen in frequency and magnitude going forward. The ongoing need to bring in renewable energy generation from the regional power grid is growing.

1. **Large infrastructure projects take time to design, undergo environmental review, and construct.**

**Any actions that replace or are identified as an alternative to the RTRP will require extensive design, permitting, environmental review, and construction, which will take the necessary time and result in development interconnection delays and potential impacts on project approvals.**

In a study conducted by the California Public Advocates Office (PAO) and released in June 2023 (attached), the average time it took to approve and complete transmission projects was 11.5 years. According to the study, the physical construction of these projects took a relatively short time, with the bulk of the time spent by oversight agencies and project developers in their detailed engineering, business development, and environmental review. The PAO undertook this study to evaluate why these projects take a long time to develop when transmission projects generally result in lower electricity rates, decreased pricing volatility in electricity markets, and increased access to clean energy. These findings were based on recent transmission development projects, including the permitting and approval process of the RTRP. Similarly, solar and other utility-scale generation projects take up to 4 to 5 years to complete in California, according to the Department of Energy's Lawrence-Berkely National Lab (see https://ei-spark.lbl.gov/generation/utility-scale-pv/project/innov/ for solar project development).

Despite significant legislation passed or introduced in late 2023 to streamline infrastructure projects, including electric transmission projects, it will still take considerable time to design, approve, and complete new transmission projects in California. Unfortunately, little of the passed legislation would reduce the time needed to approve and construct a project like the RTRP. Infrastructure streamlining legislation focused on many types of infrastructure, including roads, water, electric, schools, and others that require state agency approvals. The legislation sets requirements for the judicial system, California State Agencies, including the Departments of Transportation, Water, and Agriculture, the Energy Commission, and the Public Utilities Commission. The following briefly summarizes the bills passed as part of the Governor's infrastructure streamlining package and a few other bills that would have potentially provided some streamlining provisions to electric transmission projects.

**Governor's Infrastructure Streamlining Package:** This group of bills passed as part of the streamlining package and included Senate bills (SB) 145, 146, 147, 149, and 150 that affected infrastructure projects. They were intended to facilitate specific projects in California. They did not include facilitating electric transmission, which is not associated with constructing new solar or wind projects.

- **SB 145** only applies to wildlife crossings along Interstate 15, facilitating the development of the Brightline high-speed train project. The bill did not apply to electric infrastructure projects.
- **SB 146** allows progressive design-build of projects developed by California's Departments of Transportation (CalTrans) and Water Resources (DWR). The bill did not apply to electric infrastructure projects.
- **SB 147** allows the "take" of a fully protected species if specific conditions are met. While this bill does have some electric infrastructure provisions, it only applies to new solar and wind projects in the State of California and the electric transmission from the project to a California Balancing Authority (bulk power grid).
- **SB 149** streamlines administrative and judicial procedures if an infrastructure project is challenged under the California Environmental Quality Act (CEQA). The bill set time limits on the judicial system to limit the scope of administrative records to eliminate the need to include logistical communications and other non-substantive communications from the record and shortens the time that challenges can be filed and the timelines

under which they need to be heard and resolved by the courts. It would not shorten any timelines for the development, approval, or construction of an electric transmission project except to potentially reduce the time it would take to resolve a challenge under CEQA.

- **SB 150** only applies to state agencies to facilitate the State's access to federal Investment and Jobs Act, Inflation Reduction Act, CHIPS, and Science Act funding. The bill requires specified state agencies to convene stakeholders to identify recommendations for community benefit planning. The bill also allows a state agency to enter a project labor agreement for specific projects. This bill did not apply to electric infrastructure projects.

Other bills of interest include SB 319, SB 420 and Assembly Bill (AB) 914.

- **SB 319** requires the California Public Utilities Commission, State Energy Resources Conservation and Development Commission, and the California Independent System Operator to review a Memorandum of Understanding related to resource and transmission planning every five years and jointly develop an electrical transmission infrastructure development guidebook by July 1, 2025. Streamlining of electric transmission projects could occur under this process as these state agencies plan for expanded infrastructure. The bill can reduce the time spent coordinating between agencies and supporting an electric transmission project to get into the queue for approval.
- **The Governor vetoed SB 420** on October 7, 2023. The Governor's veto message stated in part, "While I agree with the author's intent to accelerate the development of new and needed electric transmission projects to move electricity from clean energy resources to consumers, this bill compounds existing permitting complexity for these projects by devolving permitting authority of mid-sized electric transmission projects from a single state agency to local agencies." Additionally, it is important to note that even had the bill passed, it would not have applied to many electric transmission projects, including those similar in size to RTRP. The bill limited the applicability of the streamlining provisions to projects of 138 kilovolts or smaller by allowing these smaller transmission projects to be electric distribution facilities. It would not have streamlined a project of the size of RTRP, which has power lines that are 230 kilovolts. The bill would have allowed these projects to be built without going through the current CPUC process to issue a certificate of public convenience and necessity to an investor-owned utility.
- **AB 914** became a 2-year bill in 2023 but has yet to be reintroduced and remains held under submission. The bill does apply to electric transmission projects. It modifies existing requirements for environmental review by making the timelines already in legislation mandatory unless circumstances require additional time for the process. If there is a delay, the bill would require the CPUC or other state agency building the project to prepare a report and submit it to the legislature explaining the reasons for the delay. In essence, this bill will hold the state agency accountable for meeting the timelines already in law.

None of these streamlining bills would shorten the existing processes applicable to building an electric transmission project except potentially, AB 914. AB 914 could shorten a timeline if the CPUC is the lead agency AND the environmental review was going to exceed the already required timelines to the agency to undertake and certify an environmental review.

As such, the timelines currently being experienced by electric transmission projects will generally not be shortened due to legislation adopted in 2023.

2. **Time is of the essence - currently approved projects that will impact Riverside's electric system capacity and affect future development approval processes in the City.**

The City needs the RTRP to be completed in a timely manner to support already planned and, in some cases, approved growth and development. The City of Riverside is growing and adding housing and development, expanding job and education opportunities, and expanding medical and other quality-of-life services that benefit not only existing residents of the City but also the region. These developments, whether a single development such as an apartment building, single-family housing development, commercial space, or planned development in a general plan or other document that addresses neighborhoods or areas of the City, will be required to evaluate the impact of the project on the capacity of the electric system to support the project as well as the impact that the project would have on RPU's ability to serve electricity to all of its customers.

One example is the City of Riverside's Housing Element EIR, which contemplated 31,564 additional housing units should every property in the City reach its maximum build-out. As was required by the state, the City Council approved its Regional Housing Needs Assessment (RHNA) of 18,458 housing units by approving a total of 20,995 housing units. About 79 MWs of additional peak load would be expected should they all develop – far exceeding the prudent utility maximum capacity. The Housing Element's Environmental Impact Report (EIR), required by the California Environmental Quality Act (CEQA), identified that RPU would have sufficient electric system capacity because RTRP was expected to be built and that it would provide the City with the transmission capacity necessary to meet future load growth and provide for reliability to the bulk electric power system. RPU clarified to the City's Planning Commission on September 9, 2021, that sufficient capacity would be available with the development of the approved RTRP, which would provide an additional 560 MW of capacity if constructed. Should the RTRP not be constructed or if it were to undergo a significant change or delay, housing projects that relied on the Housing Element's EIR, would be required to evaluate their impact on the peak loads in Riverside.

This would be an additional burden on development that would not only need to evaluate the project's impact on peak load but also require the project developers to mitigate the peak load impacts so that they do not negatively impact other RPU customers. Mitigation measures could include requirements to install and maintain battery energy storage systems, increased energy efficiency of the building envelop, or delay of the project's development until adequate capacity is available to safely and reliably serve the project with electricity without negatively impacting or putting other customers at risk of power outages or power quality.

Further, RPU's Engineering Division, which reviews and determines the infrastructure needs for development projects, has about 80 projects for new interconnection that will require peak capacity. These projects include:

- About 20 housing developments, including affordable housing (these sites are typically on sites that were included in the analysis for the Housing Element)
- New industrial and commercial developments
- Expansions at three hospitals and medical centers
- New EV charging and fleet charging hubs throughout the City
- Northside Specific Plan area developments
- Expansions of existing schools and new school and research facilities at K-12 and

Riverside universities

Even if some of these projects are never constructed, RPU anticipates they will result in peak load increases of over 70 MW by 2030.

The City has just begun developing its future land use vision with the launch of the new 2050 General Plan and Climate and Action Plan effort. Infrastructure capacity will be a part of the discussion. Supporting the growth and development envisioned during that effort will be necessary. Without additional electricity generation, energy storage, or transmission capacity, Riverside will need to explore mitigation for new growth and development to ensure that additional growth and development can be safely served without causing impacts to all customers on RPU's distribution system.

3. **Pressures on RPU's natural-gas power generation and consideration of renewable generation replacements.**

In addition to the risks presented by continued load growth for the system's capacity, RPU's internal generation is at risk. RPU's RERC and Springs units are aging. At this time and since 2018, there are no known spare parts (new or used) in the United States for the Springs units. Therefore, this facility is not operating unless required to meet the load. Both facilities face risks that include their system designs as peaking facilities, that there may be constraints to the availability of natural gas through the Southern California Gas Company system, and the viability of the use of natural gas for electricity generation in light of California's regulations on the combustion of fossil fuels and due to air regulations from the South Coast Air Quality Management District for air contaminants. California currently seeks to eliminate the need for fossil fuel combustion by 2045. Further, it is unrealistic to expect these generation units to continue operating beyond their operating design. As is currently being experienced, finding the parts needed to keep them operating becomes impossible.

State regulations require RPU to serve its retail load with 100% carbon-neutral resources by 2045. These resources must be 60% renewable (solar, wind, geothermal, or other renewable generation sources approved by the State), with the remaining coming from other zero-emissions resources such as large hydroelectric and potentially nuclear. Because some of these resources, such as geothermal or large hydroelectric facilities, will not be available within RPU's territory, these types of resources must be imported. Further, it is unlikely that solar and wind resources could be constructed at a utility-scale because of the large land area required for these facilities. For example, according to the U.S. Department of Energy, it takes an average of between 5 and 10 acres to produce 1 MW of solar electricity. Building a solar facility that generates as much electricity as the RERC power plant would require between 970 and 1940 acres or 1.5 to 3 square miles of land area for the solar and additional land for the batteries. RERC is currently located on a 5-acre site. Please note that the City, SCE and the CPUC considered the potential for solar (also potentially paired with energy battery storage) as an option in place of the RTRP as part of the Lower Voltage and Other Design Alternatives Report. In that analysis, replacement of the RTRP (not just the RERC units) would require 489 MW of solar photovoltaics, which would require approximately 3 to 6 square miles of land (using a less conservative average of 4 to 8 acres to produce 1 MW of electricity). The efficiency of utility-scale solar photovoltaic systems has not changed significantly in the last several years, and these estimates remain valid.

Compounding this, solar facilities only generate electricity when the sun is available, thus limiting their capacity to generate electricity for Riverside's peak hours late in the day. Therefore, large-scale battery storage systems are required. To truly utilize the variety of carbon-neutral generation resources anticipated in the coming years, a second interconnection to the regional grid will be necessary unless large areas of land with the RPU service territory are dedicated to power production. It is important to remember that battery storage systems rely on electricity generation to charge. All a battery does is store electricity generated at one time and release it for use later. Battery storage systems do not generate electricity themselves. Therefore, the electricity used in a battery must be generated within the RPU service territory or imported through a transmission system. Batteries also have a limitation on their operation and typically discharge for 1 to 4 hours, depending on their chemistry and design. While RPU staff envision that battery storage systems will play a critical role in the City's future, they are not wholesale replacements of existing generation without supporting transmission infrastructure.

RPU staff recognize that other operational aspects of its system will affect costs to both existing and future ratepayers and system reliability. RPU is part of the statewide grid operated by the CAISO. As such, RPU is subject to the tariff and rule requirements of the CAISO. One rule requires that RPU operate its internal generation to provide sufficient resource adequacy flexibility to support the overall CAISO grid, not just RPU's needs. RPU meets some of these requirements with the capacity provided by RERC and Springs. In light of the capacity limitations through Vista, the CAISO has provided RPU with the ability to dispatch the units for our internal load needs. This temporary variance to the rule, which only applies during high loading within the City, was granted only to Riverside because it actively pursued the development of the RTRP. This variance will be lost once the RTRP is completed. This consideration and all other operational aspects of the RPU system will need to be evaluated.

### 4. Addressing Wildfire Hazards from Transmission Projects

Significant concern has been expressed, indicating that new information regarding wildfire hazards from electric infrastructure exists. This section is not meant to downplay the wildfire risks presented by electric infrastructure but to provide context for discussion and address some of the key concerns that have been expressed.

*Wildfire and Electric Utility Infrastructure Oversight*
Wildfires from electric infrastructure have been a significant concern in California since the early 2000s. The CPUC and other state agencies began implementing increasingly stringent requirements on investor-owned utilities in 2008 following fires in Southern California in October 2007. Due to this, the approval process for the RTRP included extensive consideration of wildfires and mitigation to address the electrical equipment causing a wildfire as well as the impact of wildfire on electrical equipment. In 2017, the CPUC's Wildfire Safety Division was the lead agency addressing wildfire risk posed by electric infrastructure. In 2021, this responsibility was transferred to a new state agency, the Office of Energy Infrastructure Safety (OEIS), which is housed in the California Natural Resources Agency.

*Wildfire Mitigation Planning*
The OEIS states that:

> *Electrical corporations are required to prepare and submit Wildfire Mitigation Plans (WMPs) to Energy Safety for review and approval. WMPs should describe how the electrical corporation is constructing, maintaining, and operating its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire.*

SCE and RPU both prepare and submit a WMP annually to the OEIS. WMPs are updated annually with the best available information and practices that outline the actions the utilities have and will take to implement to reduce fire risks on their entire electric systems. Wildfire mitigation efforts are updated every year based on assessments of wildfire risk, the effectiveness of their efforts to mitigate fire risk, and how they incorporate best practices and measures into their operations. Annual wildfire mitigation plans are located at: https://energysafety.ca.gov/.

*Evaluation of Wildfire Risk for RTRP*

Fire hazards and the risk associated with electric infrastructure were addressed in both the City's environmental review and the CPUC proceedings. No change has been made to the HFTD maps in the area of the RTRP since the maps have been adopted and updated in subsequent years. The CPUC, in its statement denying the City of Norco's PFM, states that it incorporated the City of Riverside EIR for the RTRP, which evaluated the fire risk from overhead transmission lines, including that the RTRP would cross "abundant vegetation that may pose conditions conducive to wildfires near the banks of the Santa Ana River" demonstrating that the wildfire risk was evaluated and addressed in the initial project reviews (see the City of Riverside RTRP EIR and the CPUC Final Decision regarding the City of Norco's PFM). Enforcement of vegetation management practices and implementing mitigation measures contained in the EIR as certified would reduce potential fire impacts to less than significant. The CPUC SEIR also completed an additional analysis of the potential fire risks presented by the RTRP and came to the same conclusion.

*Wildfire Risk Mapping*

Fire hazard and risk designations for the area of the RTRP have not changed since maps were adopted. Maps for fire hazards were first created in 2007 by CalFire to show state and local fire response responsibility areas. CalFire's maps do not indicate the severity of high fire hazards in the path of the RTRP.

The more recently developed High Fire Threat District (HFTD) maps prepared for the CPUC were published in draft form in 2017 and adopted in 2018, prior to the CPUC's approval of the RTRP. These maps identify a portion of the RTRP crossing Tier 2, or higher risk of utility infrastructure related wildfires (note that this is not the highest risk designation or Tier 3, which is extreme risk). These maps are different than the CalFire maps. CalFire maps show the hazard level presented by wildfire or the likelihood of wildfire occurring. The HFTD maps show areas where electric infrastructure may pose an elevated risk of causing a wildfire but do not change the underlying fire hazard of the area.

*Transmission and Distribution Line Wildfire Risk*

Finally, it is important to understand the distinction between the different types of electrical infrastructure and the fire risk they each present. Transmission lines have a significantly lower risk of causing a wildfire because they utilize metal poles, have greater conductor line spacing, lines are further from the ground, and implement a variety of other measures that minimize the risk they present. Distribution lines present a greater risk of wildfire for various reasons, including the distance to vegetation, use of wood poles, spacing of conductor lines, age, and maintenance. Distribution lines are closer to the ground, conductor lines closer together, and have several other characteristics that result in a higher risk of the infrastructure causing a wildfire.

In summary, the RTRP is an electric transmission line that presents less fire risk than a distribution line.

## 5. Other Considerations

SCE has submitted a letter to the City of Riverside requesting action before restarting the project's construction. Additionally, Assemblymember Bill Essayli has introduced legislation (AB

3076) in the California State Assembly that, if signed into law, would require the CPUC to conduct additional environmental review of the RTRP project and potential alternatives.

*March 22, 2024 Letter from SCE President and Chief Executive Officer, Steven D. Powell*

On March 22, 2024, SCE's President and Chief Executive Officer, Steven D. Powell, submitted a letter to Mayor Patricia Lock Dawson, the Riverside City Council, and executive staff of the City, RPU, and the City Attorney's Office. The letter, attached for reference, reaffirms SCE's commitment to complete the RTRP project in as timely a manner as possible. However, to ensure that California's ratepayers do not incur financial exposure should the project change mid-construction, SCE has requested that the City take action to "firm[ly] and unconditional[ly] support the [RTRP]."

*Assembly Bill 3076, (Essayli)*

Subsequent to the CPUC action on the Norco PFM, Assemblymember Bill Essayli amended AB 3076 on March 21, 2024, to specifically address the RTRP. The bill is identified as fiscal and must be referred to a fiscal committee before proceeding to the other house for consideration. This bill failed to receive a hearing in the Assembly Committee on Utilities and Energy, its only policy committee assignment, before the April 26, 2024 deadline for bills tagged as fiscal. As such, it will not move forward in the 2024 legislative session. The 2024 legislative session is the second year of the two-year legislative cycle, and this bill cannot become a two-year bill.

AB 3076 would have directed the CPUC to suspend SCE's implementation of Decision 20-03-001 (March 12, 2020) until a supplemental environmental impact report (Supplemental EIR) was prepared and submitted for the CPUC's consideration of updated wildfire risk associated with the construction of the RTRP including the following evaluations of the impacts of the RTRP on emergency response to wildfires as well as the potential for the project to ignite a wildfire or cause the spread of a previously ignited wildfire.

The Supplemental EIR was also directed to reconsider the feasibility and environmental impacts of alternatives to the adopted RTRP route, including a fully underground alternative version of the RTRP. Finally, the supplemental EIR was also required to consider the social and economic impacts on the communities adjacent to the RTRP route as well as the environmental impacts of the RTRP in their determination to recertify the supplemental EIR and determine if the project, whether currently designed or as modified is in the public interest.

**STRATEGIC PLAN ALIGNMENT:**

This item contributes to **Strategic Priority No. 6 - Infrastructure, Mobility & Connectivity** and **Goal 6.2**. - Maintain, protect and improve assets and infrastructure withing the City's built environment to ensure and enhance reliability, resiliency, sustainability and facilitate connectivity.

This item aligns with each of the five Cross-Cutting Threads as follows:

1. **Community Trust** – Riverside is actively engaged with the Riverside Transmission Reliability Project (RTRP) and is providing timely and reliable information to inform policy makers on potential actions that may need to be taken to protect and serve the public interest.

2. **Equity** – Riverside is supportive of the City's racial, ethnic, religious, sexual orientation, identity, geographic, and other attributes of diversity and is committed to advancing the

fairness of treatment, recognition of rights, and equitable distribution of services.

3. **Fiscal Responsibility** – RTRP as designed and approved has been found to be the most economic and fiscally responsible method for project delivery to Riverside customers.

4. **Innovation** – Riverside is keeping abreast of interconnection needs to the state electric transmission grid in order to respond to and prepare for any potential impacts to the community.

5. **Sustainability & Resiliency** – The need for RTRP was derived by the need for reliable supply of electricity. Riverside's lack of sufficient electric delivery capacity from the state electric grid created a risk to the resiliency of the City. RTRP addresses those needs.

**FISCAL IMPACT:**

There are no proposed changes to the previously approved RTRP project appropriation and fiscal impact with the continuing implementation of the City portion of the RTRP and requesting that Southern California Edison reinitiate, without delay, the complete construction and operation of their portion of the RTRP. The fiscal impact of the system capacity analysis study will be presented to the Board of Public Utilities and City Council at a later date. There may be a fiscal impact to the City should the RTRP not proceed.

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| Prepared by: | David A. Garcia, Interim Utilities General Manager |
| Certified as to availability of funds: | Kristie Thomas, Finance Director/Assistant Chief Financial Officer |
| Approved by: | Mike Futrell, City Manager |
| Approved as to form: | Phaedra Norton, City Attorney |

Attachments:
1. RTRP Timeline
2. Timeline of City Council Actions after March 2020
3. RTRP Final EIR Chapter 1, Purpose and Need
4. RTRP Supplemental EIR Chapter 1.0 Introduction
5. Staff report to City Council May 10, 2022
6. CPUC Decision Granting CPCN – March 18, 2020
7. CPUC Decision Denying City of Norco Petition for Modification March 24, 2024
8. Joint RTRP Lower Voltage and Other Design Alternatives Report
9. California Public Advocates Office Report Transmission Development Timeline June 2023
10. Lawerence Berkely National Lab Report – Utility Solar Project Development and EPC
11. Letter from Southern California Edison Chief Executive Officer Steve Powell to City of Riverside dated March 22, 2024
12. Assembly Bill 3076 (Essayli) printed on April 10, 2024
13. Letter from City Council to CPUC dated October 31, 2023
14. Agreement between SCE and the City
15. Presentation