Application No.:	A.15-04-013
Exhibit No.:	RPU--
Witnesses:	Bob Tang, Ph.D. George Hanson Scott Lesch, Ph.D. Chief Jennifer McDowell Mark Annas Daniel Garcia

CITY OF RIVERSIDE

City of Riverside's Direct Testimony Supporting Southern California Edison Company's (U 338-E) Application For a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project

Before the

Public Utilities Commission of the State of California

March 1, 2019

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LIST OF FIGURES AND TABLES

I. INTRODUCTION

Q. Please describe how your direct testimony is organized.

A. This testimony is organized pursuant to the issues identified in the Assigned Commissioner's Scoping Memo and Ruling, and it focuses on issue 7: does the proposed project serve a present or future public convenience and necessity?[1], which overlaps with issue 6.

- Section II (A) provides a general description of the City of Riverside's (Riverside)[2] electric system; Riverside's current electric interconnection with Southern California Edison Company (SCE) at Vista Substation and the need for the Riverside Transmission Reliability Project (RTRP) (i) to serve Riverside's current and anticipated load growth and (ii) to provide a second point of interconnection between Riverside and SCE for redundancy purposes. A brief history of the initial project development is also provided.
- Section II (B) (1) provides an overview of Riverside's actual peak demand growth in the past ten years; Section II (B) (2)

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[1] As noted in the Assigned Commissioner's Scoping Memo and Ruling, issue 7 "directly overlaps with issue 6", which is "To the extent that the proposed project and/or project alternatives results in significant and unavoidable impacts, are there overriding considerations that nevertheless merit Commission approval of the proposed project or project alternative?". Assigned Commissioner's Scoping Memo and Ruling, at 3. Riverside believes the present and future necessity to be served by RTRP is the overriding consideration that merits Commission approval.

[2] Riverside and Riverside Public Utilities or RPU are used interchangeably in this testimony.

provides a general description of Riverside's load forecasting methodology/model; Section II (B) (3) provides a summary of the most recent load forecast for Riverside going forward; and Section II (B) (4) provides a brief summary of the evolution of Riverside's load forecasts in the past ten years.

- Section II (C) (1) explains the inadequacy of the existing interconnection between SCE and Riverside to serve Riverside's existing and anticipated load growth and explains why a second point of interconnection between SCE and Riverside is needed to reduce the dependence on the current single interconnection point and ensure reliability. Section II (C) (2) describes the use of Riverside's existing internal generation as a stopgap measure to alleviate the overload conditions at Vista and why continued dependence on Riverside's internal generation cannot be relied upon.
- Section III provides a summary of the reasons why RTRP is needed to ensure reliability of service to Riverside.

II. RTRP WOULD SERVE BOTH A PRESENT AND A FUTURE PUBLIC CONVENIENCE AND NECESSITY

A. General Description of Riverside's Electric System and the Need for the RTRP

1. Description: (a) Wires, (b) Existing Interconnection with SCE, and (c) Generation

Q. Please describe Riverside's electric system and Riverside's current interconnection with SCE.

A. Riverside owns and operates an electric utility system which provides retail electric services to its customers within the approximately 81.5 square miles within Riverside city limits. Riverside's power supply requirements are met with a combination of power purchase agreements, predominantly with power generated outside the Riverside electric system and imported into Riverside via the current interconnection with SCE at Vista Substation[3] and ownership of generating plants located within Riverside.

Q. Please describe the location of Vista Substation.

A. SCE's Vista Substation is located north of Riverside on Newport Avenue in the City of Grand Terrace.

[3] In 2017, Riverside imported approximately 96% of Riverside's 2017 energy requirements through SCE's Vista Substation. The remaining 4% of power was generated by internal, peaking power plants interconnected with Riverside's local electric system.

Figure 1 Google Earth View of Vista Substation

Q. How is Riverside connected to Vista Substation?

A. Riverside is served by seven (7) 69kV sub-transmission lines supplied by the two (2) 280 MVA transformers (Banks 1A and 2A) the Vista "C" 66kV Bus Section.

(a) **Wires**

Riverside's local electric system is comprised of 14 separate substations linked by a network of 69 kV subtransmission lines. Each substation transforms the electricity from 69 kV to 12 kV or 4 kV for distribution to Riverside's customers.

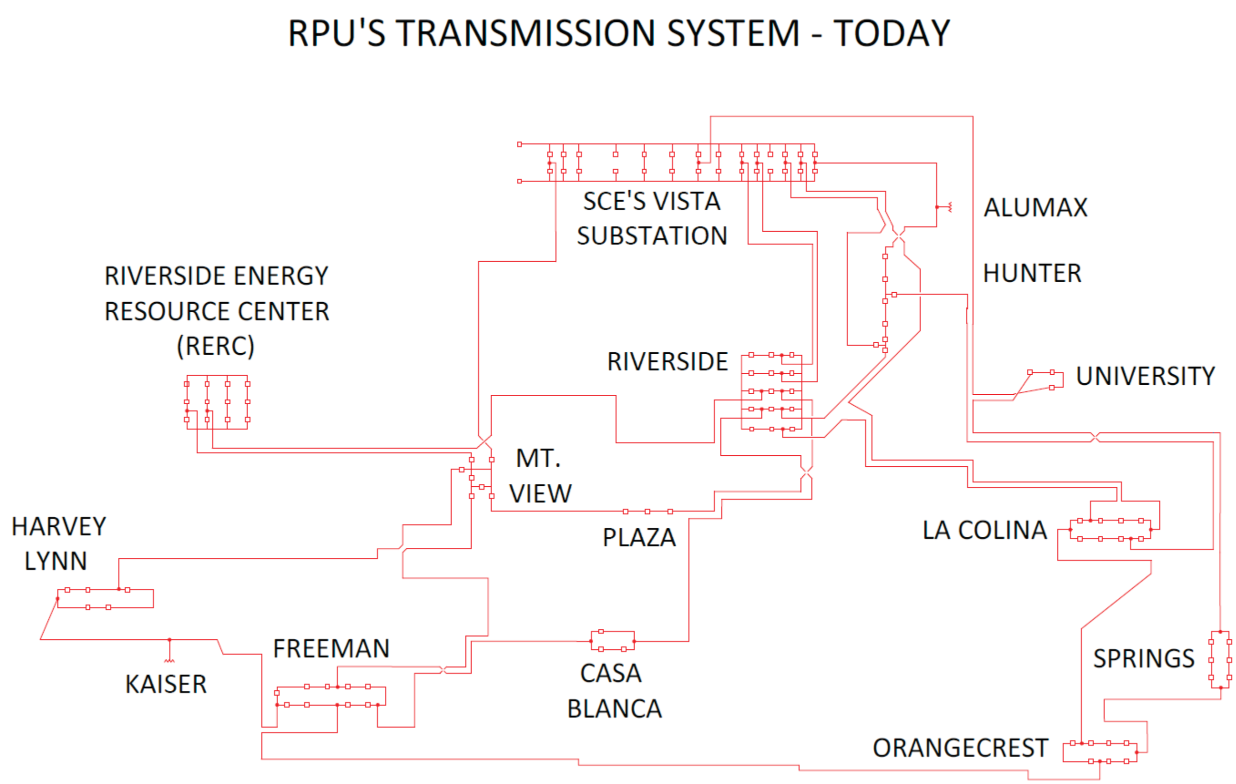

Figure 2 Single Line Diagram for RPU System

(b) Interconnection

Riverside's local electric system is served through SCE's Vista Substation via two 230/69 kV transformers, each nominally rated at 280 MVA[4] and connected to Riverside's local electric system by seven 69 kV subtransmission lines[5]. A single line diagram of Riverside's distribution system is attached in Appendix A.

[4] The interconnection at Vista Substation provides 560 MW of transfer capability from SCE to Riverside's local electric system.
[5] Appendix B summarizes the information regarding the seven 69 kV subtransmission lines from Vista Substation serving Riverside.

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(c) **Generation**

Riverside's generating capability within Riverside city limits consists of two generating stations:

- Four GE 10 units at Springs Generating Plant (Springs) commissioned in July of 2002 with a combined generating capacity of 36 MW, and
- Four GE LM-6000 units at Riverside Energy Resource Center (RERC) with the first two units commissioned in June 2006 and the remaining two units in the spring of 2011, with a combined generating capacity of 192 MW.

2. **RTRP is Needed to Meet Two Reliability Objectives: (a) to Service Existing and Forecast Load, and (b) to Provide an Additional Source of Bulk Power**

Q. Please describe the needs which RTRP is intended to address.

A. RTRP will address the following identified needs[6]:

- Increase capacity to meet Riverside's existing electric system demand and the anticipated future load growth; and
- Provide an additional interconnection point between SCE and Riverside for delivery of bulk power into

[6] See Section 1.5 of the Final Environmental Impact Report (FEIR) vol. 2 and Section 2.2 of the Executive Summary (ES2.2) of the Final Subsequent Environmental Impact Report. Both FEIR and FSEIR can be found at http://www.cpuc.ca.gov/Environment/info/panoramaenv/RTRP/

Riverside's electric system, reducing the dependence on Vista Substation and increasing overall reliability.

Q. Please explain the genesis of the RTRP.

A. Until the mid-1980s, Riverside was a full requirement wholesale customer of SCE fully dependent upon SCE for Riverside's power needs. Since the mid-1980s, Riverside began to develop a portfolio of resources to meet Riverside's power resource needs, initially focusing on baseload and intermediate resources to provide the majority of Riverside's power needs. All of these early resources were located throughout the WECC and delivered through Vista.

Beginning in the early 2000's, Riverside began developing local peaking resources to meet the growing summer system peaks. At the same time, Riverside was experiencing accelerated load growth due to the robust economic expansion in the Inland Empire region of Southern California. Riverside became concerned that it would run out of electric capacity in the foreseeable future to serve its customers reliably if the load growth trend were to continue. Riverside initiated the process of building internal generation to address the capacity insufficiency problem with three main objectives in mind:

- To meet Riverside's growing summer peak demand;

- To provide temporary loading relief to Vista Substation until a permanent transmission solution is studied and put into place to address Vista loading issue;
- To provide a source of emergency power to essential city functions (estimated at approximately 80MW).

To meet these objectives, Riverside built its first local peaking generation – Springs generation (36MW) in 2002 and followed by RERC 1 and 2 (96 MW) in 2006 while concurrently pursued with SCE permanent options to upgrade the interconnection facilities between Riverside and SCE's systems to provide additional electric capacity to Riverside.

Riverside requested SCE to study viable options to provide additional capacity to Riverside and to provide service redundancy to reduce Riverside's dependency on the single point of interconnection at Vista Substation. In late 2003, SCE presented its initial study to Riverside with a proposal to add one new transformer at the Vista Substation along with three new 69 kV subtransmission lines to serve Riverside. This proposal was deemed inadequate by Riverside as (a) it would not address Riverside's needs for additional capacity and reliability in the long term, (b) further expansions at Vista Substation to accommodate Riverside's long term needs would be infeasible due to space constraints at Vista Substation, and more importantly (c) it did not reduce Riverside's dependence on one single interconnection point at Vista Substation.

After further requests by Riverside, SCE conducted additional studies which culminated in the Facilities Study dated September 7, 2005[7] which proposed several new interconnection alternatives at 230 kV.

Option 1 of the Facilities Study proposed a new 230 kV interconnection between Riverside and SCE's systems. Option 1 included a loop-in of Mira Loma-Vista No.1 230 kV transmission line to the new interconnection facilities, and formed the basis of subsequent development leading to the current configuration of RTRP.

Option 2 was to build a 230 kV SCE interconnection facility located at Riverside's new Jurupa Substation with two new 230 kV lines from the Mira Loma and Vista substations to the new Jurupa Substation.

Option 3 was to build a new SCE 230 kV interconnection facility adjacent to the existing Mira Loma-Vista 230 kV right- of-way with new 8.25 miles of double circuit 230 kV transmission to a new Riverside 230/66 kV Jurupa Substation.

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[7] See Appendix C

Q. Please explain the rationale for RTRP, a 230 kV interconnection versus other lower voltage alternatives.

A. As mentioned above and will be further demonstrated below, Riverside needs additional capacity to serve its existing and forecast load; therefore, adding infrastructure to serve Riverside's load is necessary and unavoidable.

As discussed above, an expansion of the existing Vista Substation to accommodate Riverside's need did not prove to be feasible for the long-term given space constraints and would fail to provide the needed service redundancy to reduce Riverside's dependency on the single point of interconnection at Vista Substation.

B. RTRP is Needed to Serve Existing Load and Forecast Load Growth

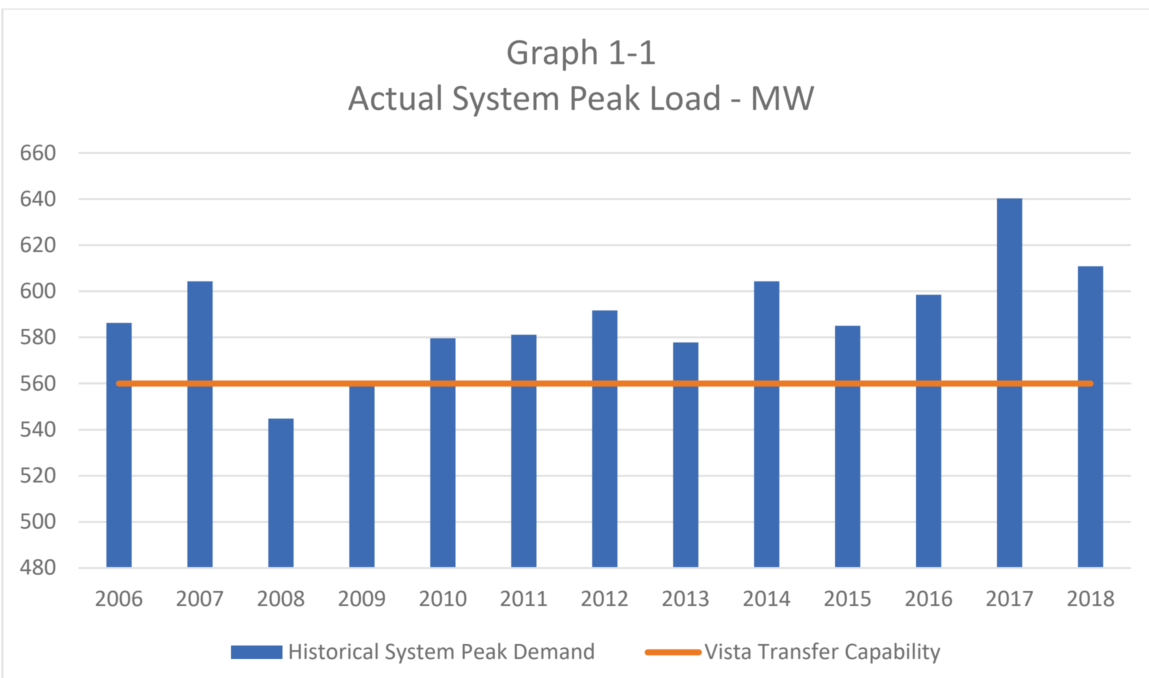
1. Actual Peak Demand Growth Over Time

Q. What has been Riverside's peak demand to date?

A. Table 1-1 below summarizes Riverside's gross system peak demand in the past thirteen years. Graph 1-1 depicts the same data against Vista's transfer capability of 560 MW.

Table 1-1 – Riverside's Historical System Peak Demand

YEAR	MW
2006	586.3
2007	604.4
2008	544.8
2009	560.3
2010	579.7
2011	581.2
2012	591.7
2013	577.9
2014	604.4
2015	585.1
2016	598.6
2017	640.3
2018	610.9



Q. What do the figures on Table 1-1 represent?

A. The figures on Table 1-1 represent the hourly integrated values of Riverside's gross load consumption[8]. Actual instantaneous system peak demands are typically higher than the hourly integrated values.

Q. Graph 1-1 seems to suggest Riverside's system peak demand has exceeded the transfer capability at Vista Substation in recent years. Please explain.

A. Yes, Riverside's gross system peak demand has consistently exceeded the Vista Substation transfer capability of 560 MW during the summer in the past thirteen years. The frequency (number of hours) and the magnitude of the largest exceedance (in MW and %) relative to the Vista transfer capability of 560 MW from 2006 to 2018 are summarized in Table 1-2 below. The more detailed hourly exceedance data for 2006 through 2018 is available upon request.

[8] Riverside's net load measurement by the aggregate of seven SCE's CAISO-certified meters at Vista Substation is added to the output of Riverside's internal generation (RERC, Springs and the Tequesquite solar project, which is a solar PV PPA with an August NQC value of 3.1MW), each individually metered by CAISO-certified meters to obtain Riverside overall system gross load figure. For the described Riverside's load calculation, the unadjusted values of CAISO-certified meter reads are used.

Table 1-2 – Riverside Load Exceedance Relative to Vista Substation Transfer Capability

Year	Riverside's System Peak	N# of hours of exceedance	Greatest Exceedance in MW	Greatest Exceedance as % of Vista Transfer Capability
2006	586.3	18	26.3	4.7%
2007	604.4	16	44.4	7.9%
2008	544.8	0	0.0	0.0%
2009	560.3	1	0.3	0.1%
2010	579.7	7	19.7	3.5%
2011	581.2	3	21.2	3.8%
2012	591.7	14	31.7	5.7%
2013	577.9	7	17.9	3.2%
2014	604.4	12	44.4	7.9%
2015	585.1	6	25.1	4.5%
2016	598.6	16	38.6	6.9%
2017	640.3	44	80.3	14.3%
2018	610.9	38	50.9	9.1%

Q. So, the frequency and the magnitude of exceedance has been trending up?

A. That is correct.

Q. What happens when Riverside's system peak demand exceeds Vista Substation transfer capability?

A. As matter of good utility practice, Vista Substation should not be allowed to be overloaded under normal operating conditions or there is the risk of potential catastrophic equipment failure or at a minimum, an accelerated loss of life of the electrical equipment. As such, Riverside has to operate its internal generating units (RERC and Springs) when the loading at Vista is expected to exceed 560 MW to reduce Vista loading to within 560 MW.

As discussed previously, Riverside's internal generation was never intended or designed to be a permanent solution to relieve Vista loading issue. As such, if Riverside's internal generating units are insufficient or unavailable to reduce potential overloads, then other mitigation measures, including in extreme circumstances, curtailment of customer loads – load shedding – must take place to reduce such overloads.

Q. Is this the way Riverside operates its local generating units to address the Vista loading issue?

A. Yes, Riverside has procedures[9] in place to operate its internal generating units when Riverside anticipates its load to approach Vista's transfer capability of 560 MW.

2. **Description of Forecast Methodology**

Q. What is Riverside's expectation of Vista loading going forward?

A. Riverside is forecasting its system peak demand will grow at least one-half percent (0.5%) per year in the next twenty years. Therefore, in the absence of RTRP, Riverside anticipates the

[9] See Riverside's internal generation dispatch procedure in Appendix D.

Vista loading issue will continue and worsen both in frequency and magnitude going forward.

Q. Please explain how Riverside does its load forecast.

A. Historically, Riverside has used regression-based econometric models to forecast Riverside's expected monthly system load (GWh), maximum hourly system peak by month (MW), as well as monthly retail loads (GWh) for Riverside's four primary customer classes – residential, commercial, industrial and miscellaneous (agricultural, traffic signals, etc.) customers.

These models are calibrated to monthly historical load and/or sales data (or maximum hourly system peak data by month) and are based on the following input variables: (a) weather summary statistics, (b) calendar effects, (c) verified expansion or contraction of specific industrial loads within Riverside not otherwise captured by the traditional economic statistics, (d) annual per capita personal income (PCPI) econometric data for Riverside's region, (e) cumulative load reduction effects associated with retail solar photovoltaic (PV) installations and measurable energy efficiency (EE) programs and (f) expected load gain due to anticipated electric vehicle (EV) penetration within Riverside's service territory.

The detailed load forecasting methodology/models along with the model assumptions is included in Appendix E.

These models have evolved over time and are periodically updated to: (a) calibrate them with the most recent observed load data/trend, (b) modify assumptions based on updated observed trends and (c) include additional input variables driven by changes in energy regulation and technology advances.

Q. Please explain how retail PV installations, EE programs and EV loads impact Riverside's load.

A. Since retail PV installations, EE programs and EV loads ultimately modify retail customers' consumption of electricity, in aggregate they modify Riverside's load either by reducing it, in the case of retail PV installations and EE programs or by increasing it, in the case of EV.

Historically, Riverside has offered and continues to offer a variety of EE programs to Riverside's customers.[10] It is estimated that EE programs have cumulatively reduced Riverside's system peak load by 40 MW through 2018 (or about 6.6% of Riverside's 2018 system peak load) and are anticipated to provide an additional 18 MW of system peak load reduction

[10] Refer to Chapter 6 and 14 of Riverside's 2018 Integrated Resource Plan at http://www.riversidepublicutilities.com/about-rpu/pdf/RPU_Full_IRP_2018_Final.pdf for a detailed discussion of the impact of Riverside's EE programs to Riverside's load consumption pattern.

through 2023 for a total of 58 MW (or about 9.6% of Riverside's forecasted system peak load in 2023).

Riverside also has maintained an active net energy metering (NEM) program for its retail customers[11] in the past fifteen years. Riverside's NEM program has contributed to the cumulative installation of 27 MW retail PV installations through 2018 (or about 4.4% of Riverside's 2018 system peak load) and it is anticipated to contribute an additional 11 MW for a total of 38 MW of retail PV installations through 2023 (or about 6.3% of Riverside's forecast system peak load in 2023).

Riverside is closely monitoring the development of EV and the trends in transportation electrification[12]. So far, the effect of EV and transportation electrification to Riverside's system peak load has been negligible and is forecasted to remain negligible through 2023.

Q. Please explain how the effects of retail PV installations, EE programs and EV loads are incorporated in Riverside's load forecast.

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[11] Refer to Chapter 18 of Riverside's 2018 Integrated Resource Plan at http://www.riversidepublicutilities.com/about-rpu/pdf/RPU_Full_IRP_2018_Final.pdf for a detailed discussion of the impact of retail PV installations in Riverside to Riverside's load consumption pattern.

[12] Refer to Chapter 17 of Riverside's 2018 Integrated Resource Plan at http://www.riversidepublicutilities.com/about-rpu/pdf/RPU_Full_IRP_2018_Final.pdf for a detailed discussion of the impact of EV and transportation electrification to Riverside's load consumption pattern.

A. The monthly effects of retail PV installations, EE programs and EV loads are independently forecasted and then inputted into the load forecasting equations as “negative” loads in cases of retail PV installations and EE programs and as a positive load in the case of EV loads. In aggregate, the combined effect of retail PV installations, EE programs and EV loads results in a reduction in the forecasted annual load growth during the forecasting period. These effects have already been accounted for in the annual load and peak forecasts.

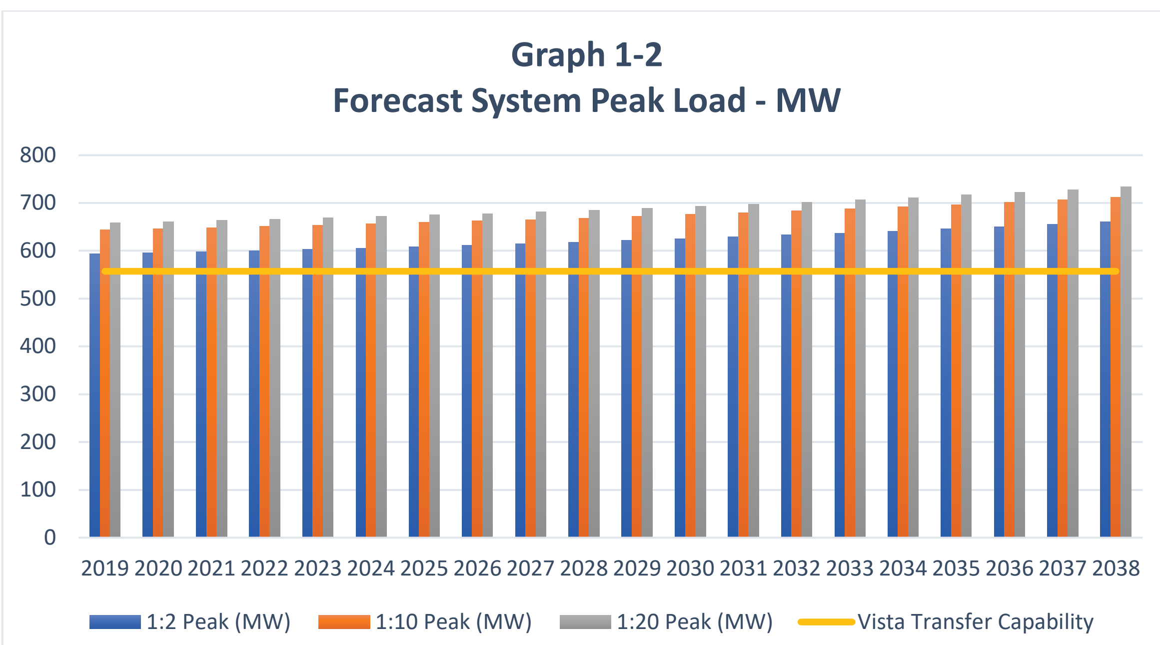
3. Current Forecast Going Forward (1:2, 1:10, 1:20)

Q. What is the most recent load forecast for Riverside?

A. The most recent load forecast for Riverside was prepared in 2017 for the purpose of preparing Riverside’s 2018 Integrated Resource Plan (IRP). Table 1-3 provides Riverside’s system peak demand for the next twenty years. Graph 1-2 depicts the same data against Vista transfer capability of 560 MW.

Table 1-3 – Load Forecast for Riverside 2018 IRP

Year	1:2 Peak (MW)	1:10 Peak (MW)	1:20 Peak (MW)
2019	593.4	644.3	658.8
2020	595.6	646.5	661.1
2021	597.9	648.8	663.6
2022	600.3	651.2	666.2
2023	602.9	653.8	668.9
2024	605.6	656.5	671.9
2025	608.5	659.3	675.0
2026	611.5	662.3	678.2
2027	614.6	665.5	681.7
2028	617.9	668.8	685.3
2029	621.4	672.2	689.1
2030	625.0	675.9	693.1
2031	628.8	679.7	697.4
2032	632.8	683.7	701.8
2033	637.0	687.9	706.5
2034	641.4	692.2	711.4
2035	645.9	696.8	716.6
2036	650.7	701.6	722.0
2037	655.7	706.6	727.7
2038	660.9	711.8	733.6



Q. Please explain what figures in Table 1-3 represent.

A. The figures in the columns represent the annual system peak demand that Riverside is expected to experience under: (1) normal summer conditions (column 1:2 Peak), (2) adverse summer conditions expected to occur once in ten years (column 1:10 Peak) and (3) adverse summer conditions expected to occur once in twenty years (column 1:20 Peak).

Q. What is the relevance of forecasting load under various conditions?

A. From an electric infrastructure planning perspective, it is important to recognize that sufficient infrastructure should be built not only to serve load under normal conditions, but also under adverse conditions. Thus, from a planning perspective, higher forecast figures are typically used to provide a safety margin to account for adverse conditions.

Q. Which load forecasts are used for the purpose of RTRP?

A. For the purpose of determining the need for RTRP, Riverside considered both 1:2 Peak load forecast to gauge the adequacy of the existing Vista interconnection with SCE going forward and 1:20 Peak load forecast to gauge the sizing of the RTRP.

Q. Why is 1:20 Peak load forecast used instead of 1:10 Peak load forecast?

A. 1:20 Peak load forecast is used to inject some conservatism in the planning process, recognizing Riverside is located in an area whereby electric generation and transmission infrastructure development is severely challenging. Furthermore, Riverside recently experienced a near 1:20 peak load event when the city recorded a peak load of 640.3 MW on August 31, 2017.[13] That said, the difference between 1:20 Peak load forecast and 1:10 Peak load forecast is no greater than 3%. Thus the conclusions regarding exceedances at Vista Substation reached for 1:20 Peak load forecast remain the same if 1:10 Peak load forecast is used instead.

4. Evolution of Riverside's Load Forecast

(a) Comparison of Current Forecast (Used for City of Riverside's 2018 IRP) to Prior Forecast (Used for City of Riverside's Certified Final EIR)

Q. How does Riverside's current load forecast compare with its original load forecast used to justify the project need?

A. The current Riverside load forecast is lower than its original load forecast. Table 1-4 summarizes the load forecast used in the Final Environmental Impact Report (FEIR) (certified in 2013).

[13] In its April 2017 Integrated Energy Policy Report Demand form filings with the California Energy Commission, Riverside submitted 2017 1:10 and 1:20 peak load forecasts of 627 MW and 641 MW on Demand Form 1.5.

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Table 1-5 shows the difference between the original load forecast and the most recent load forecast.

Table 1-4 – Riverside's Load Forecast in the FEIR

Year	System Peak under Normal Condition	System Peak under Adverse Condition[14]
2013	614	640
2014	627	670
2015	651	695
2016	672	706
2017	688	720
2018	695	730
2019	705	745
2020	715	757
2021	730	770
2022	750	783
2023	765	796
2024	775	810
2025	785	824
2026	800	836

[14] These system peak forecasts (under adverse weather conditions) were calculated by inputting the monthly cooling degrees from the warmest year in the previous twenty year time period into the load forecasting equation.

Table 1-5 – Side-by-Side Load Forecast Comparisons[15]

Year	System Peak Forecast Used in 2013 EIR	Actual System Peak Load	Deviation From the of Actual Load	System Peak Forecast in 2018 IRP	Deviation from 2018 IRP Forecast
2013	614	577.9	(36.1)		
2014	627	604.4	(22.6)		
2015	651	585.1	(65.9)		
2016	672	598.6	(73.4)		
2017	688	640.3	(47.7)		
2018	695	610.9	(84.1)		
2019	705			593.4	(111.6)
2020	715			595.6	(119.4)
2021	730			597.9	(132.1)
2022	750			600.3	(149.7)
2023	765			602.9	(162.1)
2024	775			605.6	(169.4)
2025	785			608.5	(176.5)
2026	800			611.5	(188.5)

(b) **Explanation of Differences**

Q. Please explain the difference between the previous and the current load forecasts.

A. As explained in Section 1 (B) 2 above, Riverside uses regression-based econometric models calibrated to historical load data and based on various independent input variables.

The previous load forecast prepared around the 2008 timeframe was calibrated using six years of observed monthly

[15] Weather normalized (1:2 forecast) system peak forecast figures from 2013 EIR and 2018 IRP are used.

load data. At the time, Riverside was experiencing very high yearly load growth for several consecutive years[16] and was anticipating a similar load growth trend given the forecast PCPI data for Riverside's region at the time.

The financial crisis of 2008-2009 materially reduced the load growth going forward, contributing to the lower loads.

Also, increasing retail customer EE efforts and retail customer solar PV penetration further reduced the load growth in Riverside.

The current load forecast has been calibrated with fifteen years of the most recent observed monthly load data and incorporates the current forecasts in economic growth, EE, retail solar PV and EV penetration in Riverside.

(c) **Demonstration of Continued Need for RTRP With Current, Lower Forecast**

Q. Does the lower load forecast eliminate the need for RTRP?

A. No, it does not. The inadequacy of the existing Vista interconnection to serve Riverside's current and future load growth under normal and contingency conditions has persisted despite the lower load forecast and will continue to persist and

[16] Riverside's system peak demand increased from 515 MW in 2003 to 604 MW in 2007, or an average annual compound growth rate of over 4% per year.

worsen without RTRP. The lower load only affects the degree of severity but does not eliminate the inadequacy.

C. RTRP is Needed to Provide an Additional Source of Bulk Power

1. Due to the Inadequacy of the Existing Interconnection, a Second Interconnection is Needed to Provide an Additional Source of Bulk Power

Q. Please explain the inadequacy of Vista interconnection to serve Riverside's existing and future load growth.

A. In order to determine the adequacy of Vista transfer capability, it is necessary to focus on the load serving capability of Vista interconnection under normal and contingency operating conditions. Vista's transfer capability of 560 MW is inadequate to serve Riverside's existing and future load growth both under normal and contingency operating conditions. [17]

(a) Demonstration of Past Exceedance of Vista

Q. Please explain why Vista interconnection is inadequate to serve Riverside's existing and future load growth under normal operating conditions.

A. Whenever Riverside's system peak demand exceeds 560 MW, the two transformers at Vista used to serve Riverside will be

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[17] *See* Data Request Set A. 15-04-013 RTRP-CPUC Deficiency Report-SCE-002, dated 12/2/2015, Question 17.

loaded above their rated capability. It is widely accepted in electric industry practice[18] that such overloads should not be allowed to happen when all electric equipment are operating normally without unforeseen equipment outages.[19]

Table 1-1 shows that Riverside's gross system peak demand in the past thirteen years exceeded Vista's transfer capability of 560 MW as early as in 2006 and has since routinely exceeded Vista's transfer capability of 560 MW. Such exceedance typically occurs during the summer months of June through September when Riverside's system load peaks, and instances of such exceedance have grown both in frequency and magnitude over the past thirteen years. Therefore, the transfer capability of the two transformers at Vista serving Riverside's gross load has been inadequate to serve Riverside's load under normal operating condition (N-0) for the past thirteen years.

(b) **Forecast of Future Exceedance of Vista**

Q. Is there a likelihood of future exceedance of Vista?

A. Yes. As Riverside forecasts continued load growth going forward, such inadequacy is expected to continue and worsen under normal operating conditions.

[18] Please refer to NERC Reliability Standards for the Bulk Electric System of North America, specifically TPL-001-4, table 1. In Appendix G.
[19] The condition under which all electric equipments are operating normally is termed N-0 condition in the electric industry.

Table 1-6 tabulates the magnitude of the expected exceedance of Vista transfer capability based on the most recent Riverside 2018 IRP load forecasts described in Section II (B) (3).

Table 1-6 – Exceedance of Riverside's Forecast Peak Demand

Year	Riverside's System Peak - 1:2 Peak Load	Greatest Exceedance in MW - 1:2 Peak Load	Greatest Exceedance as % of Vista Transfer Capability of 560 MW	Riverside's System Peak - 1:20 Peak Load	Greatest Exceedance in MW - 1:20 Peak Load	Greatest Exceedance as % of Vista Transfer Capability of 560 MW
2019	593.4	33.4	6.0%	658.8	98.8	17.6%
2020	595.6	35.6	6.4%	661.1	101.1	18.1%
2021	597.9	37.9	6.8%	663.6	103.6	18.5%
2022	600.3	40.3	7.2%	666.2	106.2	19.0%
2023	602.9	42.9	7.7%	668.9	108.9	19.5%
2024	605.6	45.6	8.1%	671.9	111.9	20.0%
2025	608.5	48.5	8.7%	675.0	115.0	20.5%
2026	611.5	51.5	9.2%	678.2	118.2	21.1%
2027	614.6	54.6	9.7%	681.7	121.7	21.7%
2028	617.9	57.9	10.3%	685.3	125.3	22.4%
2029	621.4	61.4	11.0%	689.1	129.1	23.1%
2030	625.0	65.0	11.6%	693.1	133.1	23.8%
2031	628.8	68.8	12.3%	697.4	137.4	24.5%
2032	632.8	72.8	13.0%	701.8	141.8	25.3%
2033	637.0	77.0	13.7%	706.5	146.5	26.2%
2034	641.4	81.4	14.5%	711.4	151.4	27.0%
2035	645.9	85.9	15.3%	716.6	156.6	28.0%
2036	650.7	90.7	16.2%	722.0	162.0	28.9%
2037	655.7	95.7	17.1%	727.7	167.7	29.9%
2038	660.9	100.9	18.0%	733.6	173.6	31.0%

(c) **Demonstration of Need for RTRP to Reliably Serve Load Without Overloading Vista in N-0 Conditions**

Q. What does the data show for a normal operating condition?

A. The above data shows that without RTRP, it is expected that Riverside's system peak load will exceed Vista's 560 MW transfer capability in the 2019-2038 timeframe to range between 6.0% and 18.0% under typical load forecast (1:2 Peak Load) and 17.6% to 31.0% under high load forecast (1:20 Peak Load). This should not be allowed to happen from a reliability standpoint.

Therefore, RTRP is needed to ensure Vista is not overloaded under normal operating conditions.

Q. Doesn't Riverside have internal generation that could be used to address Vista loading problem?

A. In part, yes. Riverside has relied upon Riverside's internal generation since 2006 to address Vista's loading problems that were surfacing when RTRP was still in the planning phase and will need to continue to rely on Riverside's local generation to address Vista's loading problems until RTRP is built to address Vista's overloading issues under normal operating conditions.

However, this reliance on Riverside's internal generation has been and will continue to be insufficient to address the inadequacy of Vista's transfer capability under contingency conditions.

Section II (C) 2 provides a detailed discussion of the uncertainties associated with the use of Riverside's internal generation in the future.

(d) Demonstration of Need for RTRP to Avoid Load Shedding in N-1 Conditions

Q. Please explain why relying on Riverside's local generation is not sufficient to address the inadequacy of Vista's transfer capability under contingency conditions.

A. It is widely accepted electric industry practice[20] that the electric system should be planned to withstand a single failure of system components – e.g. transformers, electric circuits, electric power generating units, etc.[21] – without resorting to interrupting firm electric services to retail customers, i.e. load shedding. In Riverside's case, the failure of a single transformer at Vista Substation poses significant risks of load shedding in Riverside if the failure were to occur during summer load conditions.

When one of the transformers at Vista fails[22], the transfer capability into the Riverside system from Vista is reduced by approximately half, from 560 MW to 280 MW through the remaining Vista transformer. When combined with Riverside's then available RERC generation of 96 MW,[23] such a failure

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[20] Please refer to Appendix G, table 1.

[21] The condition under which a single failure in system component is termed N-1 condition in the electric industry.

[22] The failure of a single Vista transformer has happened previously in late 2007 due to a failure of load tap changer.

[23] Riverside's RERC generation capability was 96 MW from 2006 through 2010 with RERC units 1 & 2 and 192 MW from 2011 to present with the addition of RERC units 3 & 4 in 2011. For this analysis, it is assumed that all available Riverside's RERC generating units were already online generating power.

would result in a total load serving capability of 376 (280+96) MW from 2006 through 2010 and 472 MW (280+192) MW from 2011 through present for Riverside's system under this N-1 condition.

The total load serving capability of the remaining Vista transformer plus the available RERC generation is woefully inadequate to serve Riverside's system load in the summer. As shown in Tables 1-1 and 1-3 above, Riverside's actual gross annual system peak demand has routinely exceeded this load serving capability by a wide margin every year over the past thirteen years and is forecasted to exceed the current N-1 load serving capability of 472 MW by wide margins in the future as well. Tables 1-7 and 1-8 tabulate the historical and forecasted exceedances under this N-1 condition, respectively.

Table 1-7 – Historical Exceedance of Riverside's Load Serving Capability under Vista N-1 Condition

Year	Vista Capacity Nameplate of One Transformer MW	Riverside's Generation (RERC only) MW	Total Capacity (Vista plus Generation)	Riverside's Gross System Peak Load MW	Greatest Exceedance vs MW	Greatest Exceedance as % of Total Capacity	N# of hours Riverside's load exceeded the total load serving capability (*)
2006	280	96	376	586.3	210.3	75.11%	819
2007	280	96	376	604.4	228.4	81.57%	718
2008	280	96	376	544.8	168.8	60.29%	898
2009	280	96	376	560.3	184.3	65.82%	653
2010	280	96	376	579.7	203.7	72.75%	359
2011	280	192	472	581.2	109.2	39.00%	101
2012	280	192	472	591.7	119.7	42.75%	214
2013	280	192	472	577.9	105.9	37.82%	148
2014	280	192	472	604.4	132.4	47.29%	150
2015	280	192	472	585.1	113.1	40.39%	172
2016	280	192	472	598.6	126.6	45.21%	221
2017	280	192	472	640.3	168.3	60.11%	318
2018	280	192	472	610.9	138.9	49.61%	280

(*) The number of hours that Riverside's load was above the SCE provided capacity plus the generating capacity of its RERC facilities. This is a comparison of the Riverside hourly load values versus the total load serving capability, which is the sum of one Vista transformer nameplate rating of 280 MW and then available RERC generation capability. The total Load serving capability was 376 MW (280+96) from 2006 through 2010 with RERC units 1 and 2, and 472 MW (280+192) from 2011 to present with the addition of RERC units 3 and 4 in 2011.

Table 1-8 – Forecast Exceedance of Riverside's Load Serving Capability under Vista N-1 Condition

Year	Vista Capacity Nameplate of One Transformer MW	Riverside's Generation (RERC only) MW	Total Capacity (Vista plus Generation) MW	Riverside's Gross System Peak Load 1:2 MW	Riverside's Gross System Peak Load 1:20 MW	Greatest Exceedance (1:2 Peak Load) vs Total Capacity MW	Greatest Exceedance (1:2 Peak Load) as % of Total Capacity	Greatest Exceedance (1:20 Peak Load) vs Total Capacity MW	Greatest Exceedance (1:20 Peak Load) as % of Total Capacity
2019	280	192	472	593.4	658.8	121.4	43.4%	186.8	39.6%
2020	280	192	472	595.6	661.1	123.6	44.1%	189.1	40.1%
2021	280	192	472	597.9	663.6	125.9	45.0%	191.6	40.6%
2022	280	192	472	600.3	666.2	128.3	45.8%	194.2	41.1%
2023	280	192	472	602.9	668.9	130.9	46.8%	196.9	41.7%
2024	280	192	472	605.6	671.9	133.6	47.7%	199.9	42.4%
2025	280	192	472	608.5	675.0	136.5	48.8%	203.0	43.0%
2026	280	192	472	611.5	678.2	139.5	49.8%	206.2	43.7%
2027	280	192	472	614.6	681.7	142.6	50.9%	209.7	44.4%
2028	280	192	472	617.9	685.3	145.9	52.1%	213.3	45.2%
2029	280	192	472	621.4	689.1	149.4	53.4%	217.1	46.0%
2030	280	192	472	625.0	693.1	153.0	54.6%	221.1	46.8%
2031	280	192	472	628.8	697.4	156.8	56.0%	225.4	47.8%
2032	280	192	472	632.8	701.8	160.8	57.4%	229.8	48.7%
2033	280	192	472	637.0	706.5	165.0	58.9%	234.5	49.7%
2034	280	192	472	641.4	711.4	169.4	60.5%	239.4	50.7%
2035	280	192	472	645.9	716.6	173.9	62.1%	244.6	51.8%
2036	280	192	472	650.7	722.0	178.7	63.8%	250.0	53.0%
2037	280	192	472	655.7	727.7	183.7	65.6%	255.7	54.2%
2038	280	192	472	660.9	733.6	188.9	67.5%	261.6	55.4%

When one transformer at Vista fails, the remaining Vista transformer will momentarily pick up Riverside's load at that time. Table 1-7 shows that if this N-1 condition had occurred in the past thirteen years, the remaining Vista transformer would have been overloaded potentially for hundreds of hours even with Riverside's internal generation online. The maximum overloads would have ranged from a low of 37.8% in 2013 to a high of 81.60% in 2007. It should be noted that it is because of the great concern Riverside had with the increasing overload condition and the long lead time to get transmission built, Riverside took the proactive step of adding RERC units 3 and 4 in 2011 which ameliorated the potential overload under N-1 condition. However, the potential overload was not eliminated and has continued to trend up since 2011.

Further, Table 1-8 shows that overloads of the remaining Vista transformer in service will continue to grow in magnitude whether under a typical load forecast or a high load forecast even assuming all available RERC generation are online.

Although transformers are typically designed to withstand some overloads of short duration,[24] the size and the frequency of the

[24] It is generally accepted industry practice for the electric system operators, in this instance SCE, to operate their substation power transformers over the nameplate values of those power transformers under contingency conditions. Operation above the nameplate values come at the expense of shortened life expectancy of the

expected overloads if this N-1 condition had occurred in the past thirteen years or were to occur in the future would subject Riverside to significant exposures to load shedding if it were to occur during summer load conditions.[25]

In conclusion, Riverside's retail customers will be subjected to significant load shedding exposures if an N-1 transformer outage condition were to happen at Vista during summer even if Riverside operates all of its internal generating units.

Therefore, RTRP is needed to eliminate the exposures of load shedding of Riverside's retail customers under N-1 conditions in Riverside in accordance with prudent utility planning and practices.

Q. Are there any other issues that RTRP is intended to address?

A. Yes. RTRP will also significantly improve Riverside's load serving capability under multiple contingency conditions by building a second interconnection point between Riverside and SCE and providing the necessary redundancy to deal with more severe contingencies.

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transformer and are only considered acceptable for infrequent contingency conditions.

[25] The load shedding events cannot be predicted with precision and are a function of tools available to the grid operators, usually in the form of emergency operating procedures to transfer portions of load in the part of system with stress to other parts of the system that are less stressed. Such operational procedures tend to be of limited duration and may not be available under all system conditions.

(e) Demonstration of Need for RTRP to Avoid Blackouts in N-2 Conditions

Q. Please explain why it is important to have a second interconnection point between Riverside and SCE.

A. It is widely accepted electric industry practice that electric systems[26] should be prudently designed to withstand multiple failures in system components – e.g. transformers, electric circuits, electric power generating units, etc.[27] – with sufficient operational flexibility and redundancy. In situations where multiple failures occur, load shedding is allowed to take place as part of the process to restore system to normality. However, the system should be prudently designed with sufficient flexibility/redundancy to reasonably limit such load shedding in magnitude and duration.

In Riverside's case, multiple component failures at Vista can cause Vista to become completely out-of-service for Riverside, resulting in very severe service interruptions to Riverside's customers.

If Vista were rendered completely unavailable to transfer power into Riverside, then Riverside's only load serving capability would have to come from Riverside's internal generating units with

[26] Please refer to Appendix G: NERC Reliability Standards for the Bulk Electric System of North America, specifically TPL-001-4, table 1.
[27] The condition under which multiple failures in system component is generally termed N-2 condition in the electric industry.

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a combined generating capability of 132 MW from 2006 through 2010 with Springs units and RERC units 1 and 2 and 228 MW from 2011 to present with the addition of RERC units 3 and 4 in 2011. Tables 1-9 and 1-10 tabulate the actual and forecasted exceedances of Riverside's load serving capability if Vista were completely unavailable.

Table 1-9 – Historical Exceedance of Riverside's Load Serving Capability if Vista is completely out of service

Year	Riverside's System Peak	N# of hours Riverside's load exceeded the total load serving capability(*)	Greatest Exceedance in MW**	Greatest Exceedance as % of Riverside System Peak Demand
2006	586.3	8,760	454.3	77.5%
2007	604.4	8,760	472.4	78.2%
2008	544.8	8,784	412.8	75.8%
2009	560.3	8,760	428.3	76.4%
2010	579.7	8,760	447.7	77.2%
2011	581.2	4,953	353.2	60.8%
2012	591.7	5,530	363.7	61.5%
2013	577.9	5,477	349.9	60.5%
2014	604.4	5,637	376.4	62.3%
2015	585.1	5,642	357.1	61.0%
2016	598.6	5,506	370.6	61.9%
2017	640.3	5,656	412.3	64.4%
2018	610.9	5,480	382.9	62.7%

(*) The number of hours that Riverside's load was above the generating capacity of its facilities. This is a comparison of the Riverside hourly load values versus the total load serving capability which is the sum of only the then available RERC generation capability and Springs generation capability. ** The total load serving capability was 132 MW (36+96) from 2006 through 2011 with RERC units 1 and 2, and 228 MW (36+192) from 2011 to present with the addition of RERC units 3 and 4 in 2011. The net difference of Riverside's peak demand less the generating capacity.

Table 1-10 – Forecast Exceedance of Riverside's Load Serving Capability
if Vista is completely out of service

Year	Riverside's System Peak - 1:2 Peak Load	Greatest Exceedance of Riverside's 1:2 Peak Load>228 MW	Greatest Exceedance as % of Riverside System Peak Demand	Riverside's System Peak - 1:20 Peak Load	Greatest Exceedance of Riverside's 1:20 Peak Load>228 MW	Greatest Exceedance as % of Riverside System Peak Demand
2019	593.4	365.4	61.6%	658.8	430.8	65.4%
2020	595.6	367.6	61.7%	661.1	433.1	65.5%
2021	597.9	369.9	61.9%	663.6	435.6	65.6%
2022	600.3	372.3	62.0%	666.2	438.2	65.8%
2023	602.9	374.9	62.2%	668.9	440.9	65.9%
2024	605.6	377.6	62.4%	671.9	443.9	66.1%
2025	608.5	380.5	62.5%	675.0	447.0	66.2%
2026	611.5	383.5	62.7%	678.2	450.2	66.4%
2027	614.6	386.6	62.9%	681.7	453.7	66.6%
2028	617.9	389.9	63.1%	685.3	457.3	66.7%
2029	621.4	393.4	63.3%	689.1	461.1	66.9%
2030	625.0	397.0	63.5%	693.1	465.1	67.1%
2031	628.8	400.8	63.7%	697.4	469.4	67.3%
2032	632.8	404.8	64.0%	701.8	473.8	67.5%
2033	637.0	409.0	64.2%	706.5	478.5	67.7%
2034	641.4	413.4	64.5%	711.4	483.4	68.0%
2035	645.9	417.9	64.7%	716.6	488.6	68.2%
2036	650.7	422.7	65.0%	722.0	494.0	68.4%
2037	655.7	427.7	65.2%	727.7	499.7	68.7%
2038	660.9	432.9	65.5%	733.6	505.6	68.9%

Table 1-9 shows that if Vista was completely unavailable, Riverside would have experienced severe service interruptions in the past thirteen years. The magnitude of such service interruptions would have been at least 60% of Riverside's load[28] if Vista unavailability had occurred at Riverside's system peak time. The duration of such interruption could easily have been many hours and potentially days as Riverside's summer load routinely exceeds 228 MW even during summer nighttime hours.

Table 1-10 shows the magnitude of the potential service interruption will continue to grow in the future both under typical load forecast or high load forecast.

It should also be noted that this is not only a summer problem as indicated by the extensive number of hours that Riverside's system load exceeded Riverside's internal generating capability in each of the past thirteen years in Table 1-9.

(f) **Discussion of 2007 Blackout**

Q. Has Riverside ever experienced a complete service unavailability from Vista?

A. Riverside did indeed experience a complete service outage episode on October 26, 2007.[29]

Q. How did Riverside's Office of Emergency Management and Fire Department assess the impacts of the blackout?

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[29] An earlier incident on July 3, 2005 at Vista Substation caused partial service disruptions to Riverside. The 2005 incident was described in SCE's data response to Cal. Public Advocates-SCE-003 Question 6(d) (attached as Appendix F).

A. Riverside's Office of Emergency Management ("OEM") assessed the impacts of the 2007 city-wide blackout, and noted the following further impacts:

- Traffic signals lost power or went to four-way flash, creating unsafe conditions for the public and first responders.
- Cell towers lost power due to only having four to eight hours' worth of battery backup, creating both internal and external communication challenges for both coordinating the incident response and receiving calls from the public. \
- Riverside's community centers, which also serve as reception and shelter locations, lost power and had only limited capabilities.

Riverside's Fire Department ("RFD") also assessed the impacts of the 2007 outage and noted the following impacts:

- A significant increase in calls for service and, as a result, a dramatic increase in response times as well.
- During the blackout, streetlights were not functioning correctly and it was raining which caused a significant delay for RFD.
- The dispatch center, under the direction of the Operations Chief had to "Prioritize" calls, which is also not typical for RFD responses. Additional personnel were also called in to work to respond to calls for service due to the fact that RFD's call volume exceeded its normal capability.

Q. What impact would a similar blackout today have on Riverside customers?

A. Riverside's OEM is charged with coordinating all city departments to prepare for, respond to, and recover from man-made or technological emergencies and natural hazards. OEM is also responsible for assisting with hazard mitigation prior to a disaster. As such, the RTRP was identified as a high priority mitigation project in Riverside's Local Hazard Mitigation Plan for 2012 and

2018. It is Riverside's duty to ensure that first responders always, and under all circumstances, have access to equipment and basic infrastructure such as reliable electricity.

If a city-wide blackout occurred today, these issues would be exacerbated by increased cell phone use and a reduction in landline use since 2007. More people could be put at risk by not being able to communicate with 911 dispatch centers.

Riverside is home to the county, state and federal governments, is home to more colleges and universities than any other neighboring city, and has two regional medical centers and a number of hospitals and clinics. In addition, Riverside is home not only to Riverside's Emergency Operations Center but also the County Operational Area Emergency Operations Center and numerous County Department Operations Centers, including Public Health and two Public Safety Answering Points (911 dispatch centers). Some of these facilities may have generator backup power, but that is not as reliable as being on the power grid. A generator failure would likely cause disruptions to Riverside's and/or the County's 911 network. Riverside's Emergency Operations Center capabilities would be degraded if power went out and the generator failed. As the Inland Empire's hub, losing Riverside's only connection to the grid would adversely impact not only Riverside but the region.

RFD also assessed the impacts if a city-wide blackout were to occur today. RFD views "Critical Infrastructure" as anything that delays the department's ability to respond to a given incident. RFD relies on electricity to respond to emergencies in an expedient manner.

Each of Riverside's fire stations house an emergency generator to temporarily keep electricity going during power outages. If power was lost for extended periods of time, RFD could potentially lose the ability to receive calls within the fire station from dispatch (Alerting system failure), open the apparatus bay doors, input calls into RFD's record management system or even pump fuel into the fire apparatus.

In 2018, RFD responded to over 38,000 calls for service, which equates to just over 100 calls per day during "normal" operations. In the event of a power outage, Riverside will experience a dramatic increase in call volume from the members of the public who rely on electricity. It is important to note that some members of the public utilize electric powered medical equipment to function. In less extreme cases, RFD may respond to assist a member of the public who is anxious.

Had the 2007 blackout occurred during summer load conditions, the restoration of service would have been much more challenging. The magnitude and the duration of the blackout to

Riverside would have been much more extensive and the impacts to Riverside's customers would have been much more severe.

(g) Impacts of a Vista Substation Outage

Q. Do you know what caused the October 26, 2007 blackout?

A. In the early morning hours on that day, one of SCE's 115 kV lines in the vicinity of Vista Substation experienced a fault of unknown cause which was not properly cleared by the line protection equipment. The fault resulted in this 115-kV line to sag into several 69 kV lines, including several 69 kV lines serving Riverside. The outcome of these cascading events was the complete outage of Vista Substation for several hours, affecting all of Riverside's customers and some of SCE's customers.

Q. What impact did this blackout in 2007 have on Riverside customers?

A. At the time of this outage, Riverside's load was approximately 240 MW, less than half of Riverside's typical summer load. The two RERC generating units existing at the time were out of service on a scheduled maintenance outage and the Springs generating units failed to start due to a communication failure. This left Riverside with no internal generation to serve its load at the time the Vista outage occurred. The entire city of Riverside suffered a complete blackout in the first two hours immediately following the outage, including traffic signals. Service was slowly restored to Riverside's customers after SCE cleared the faults and rerouted the power. It took four hours from the start of the outage to completely restore service to Riverside's customers.

Q. What would happen if the entire Vista 220kV bus went out?

A. In the event of the loss of the Vista 220kV bus, extensive load shedding is expected to be required as Riverside does not have sufficient internal generation to serve its entire load for most of the time during the year; moreover, Riverside does not know how long it could take for SCE to repair the entire Vista 220 kV bus.

Q. What would happen if the 66kV C bus section went out?

A. In the event of the loss of the 66kV C bus section, Riverside's electric system would be isolated from the California Independent System Operator (CAISO) Grid until repairs are completed. Riverside's generators would be started, if available, using black start procedures to allow shed load to be restored. Loads in excess of available capacity would need to be shed or provided power on a limited basis by rotation.

Rotating power outages affecting Riverside customers would likely be required until repairs are completed.

i. Services and Populations Impacted

Q. How does Riverside prioritize its customers to decide the order in which their power service will be restored?

A. Riverside groups our customers into the following classifications to determine priority for restoration:

1. Government and other agencies providing essential fire, police, and prison services

- County of Riverside Emergency Operations Center
- City of Riverside Emergency Operations Center
- Robert Presley Detention Center
- City Hall
- Magnolia Police Station
- Orange Police Station
- 311 Call Center at Orange Square

2. Government agencies essential to the national defense

3. Hospitals and Licensed Urgent Care Medical Facilities where surgery is performed

- Riverside Community Hospital
- Kaiser Hospital
- Parkview Hospital

4. Communication utilities related to public health safety and welfare including telephones

- AT&T switching centers

5. Navigation communication traffic control and landing and departure facilities for air and sea operations

- FAA aviation control tower at Riverside Municipal Airport

6. Electric utility facilities and supporting fuel and fuel transportation services critical to continuity of electric power system operation

- Utilities Operations Center

- RERC Generating Station
- Springs Generating Station

7. Radio and television broadcasting stations used for broadcasting emergency messages instructions and other public information related to the electric curtailment program

8. Water and sewage treatment utilities may request partial or complete exemption in times of emergency identified as requiring their service such as fire fighting

- Riverside Public Utilities Water Pumping Stations
- Western Municipal Mills Filtration Plant
- Riverside Regional Water Quality Control Plant

9. Rail rapid transit systems as necessary to protect public safety

- Metrolink Stations Hunter Park, Downtown and La Sierra
- Amtrak

10. Customers with specific curtailment agreements providing Rotating Outage or participating in Riverside's Power Partners Program with a minimum of 200 kW

11. Critical life support Utilicare customers

Q. Please characterize the impact of the loss of reliable electric service on the City of Riverside.

A. Riverside is home to critical county facilities, including the county emergency communication center, and a regional water filtration plant, and is the seat of county government. Riverside provides essential electric service to the seat of county government, which includes important emergency, public health and safety services. A disruption in support for these critical services due to loss of reliable electric service would be traumatic; it would also affect all branches of county government. Critical support for hospital services, outpatient and nursing care facilities could be impacted, placing vulnerable populations (the sick, elderly and infirm) at risk. Riverside's universities, schools and other educational facilities also all depend on reliable electric service to provide their necessary services to the community. A prolonged loss of reliable electric service would be devastating, particularly during a prolonged heat storm.

Q. Have any of Riverside's essential emergency service customers and facilities expressed concern over the potential risk of rotating outages or blackouts?

A. Yes, they have. Included in Appendix H are letters from several of them.

ii. Outage Management and Restoration

Q. Please describe Riverside's process for managing an outage and power restoration.

A. Riverside would undertake the following sequential steps to restore its system:

1) Restoration Efforts

   a) Black start program for internal generation (Springs and RERC)

b) Step by step switching program for system sectionalizing and restoration

c) Prioritized list of circuits based on priority for restoration

d) Step by step switching programs to isolate non-essential loads from circuits serving essential emergency service loads.

e) Rotating outage plan for rationing power service to unserved loads.

2) Duration

a) Depending on the time of day, day of the week and availability of staffing to perform switching, the plan would take hours to complete initial service restoration to essential emergency service loads.

b) Providing rotating service to unserved loads would commence after essential emergency service loads are restored, subject to available capacity and available crews for switching operations. Rotating service would require switching on a regular basis based on the rotation cycle time.

Q. Can you describe the work effort this outage management and restoration would require of the City of Riverside?

A. Yes; the work effort required would entail the following:

a) Full staffing of the grid control center: supervisor plus three dispatchers, minimum, per shift.

b) Full staffing of the Water SCADA system: water system operators to manage power losses at water facilities.

c) Multiple electric field and substation crews each shift to perform field switching.

d) Partial Department Operations Center activation to provide

   i. Operation section for control of water and electric field crews

   ii. Planning/Intelligence section to develop operational plans and switching programs.

   iii. Public Information Officer to assist Riverside in providing utility specific information for the duration of the event.

e) Full staffing at RERC and Springs Generation stations to support generation operations.

f) Full staffing of the 311 Call Center to identify and classify calls for service.

g) Activation of the Customer Engagement emergency program to keep major accounts informed and to press for energy conservation.

h) The City Emergency Operations Center may need to be activated to coordinate response for all Riverside Departments and coordinating agencies.

The 2007 outage incident showed that a complete outage of Vista can credibly happen and, when it happens, could result in severe service interruptions to Riverside's customers. If Riverside had a second interconnection point with SCE, the service interruption to Riverside's customers could have been avoided in this particular instance, as power could have been rerouted to the second interconnection point to serve Riverside's customers when Vista became unavailable.

In conclusion, the sole dependence on Vista interconnection poses significant risks to Riverside in terms of potentially severe and prolonged service interruptions to Riverside customers.

Therefore, RTRP is needed to provide the redundancy to avoid severe service interruptions to Riverside customers in the event of a Vista outage.

Q: Will RTRP provide a second point of interconnection between Riverside and SCE?

A: Yes, RTRP will provide a new second point of interconnection between Riverside and SCE and will significantly ameliorate the service reliability to Riverside under contingency conditions.

2. Use of Existing Internal Generation Cannot Alleviate Overload Conditions

Q. Why did Riverside install Springs and RERC?

A. Both Springs and RERC were installed to mitigate the risk of a load exceedance or a loss of power to Riverside from Vista. Springs was installed to address the expected exceedance of Vista and supply critical loads in the event of a blackout, as well as help to meet Riverside's capacity need. RERC was commissioned to further Riverside's goal of building and maintaining reliable infrastructure and reduce dependence on a single point of infrastructure; Riverside recognized that internal generation would improve system reliability in the event of transmission grid disruption and installed the internal generation.[30]

Q. It was mentioned that continued reliance on Riverside's internal generation in the future is uncertain. Please explain.

A. There are multiple challenges facing Riverside's internal generation to deliver the relief to the Vista loading problem in the future. These challenges include:

- Age of Riverside's internal generating units
- Operational design of RERC and Springs (peaking plants)

[30] City Council Memorandum, dated Dec. 7, 2004, attached as Appendix I

- Gas availability in the context of constrained Southern California Gas Company (SoCal Gas) system
- Competing operational needs for RERC units
- Long-term viability of RERC and Springs in light of the state's greenhouse gas (GHG) reduction goals

3. **Age of Existing Local Generating Units**

Q. Please explain how the age of existing internal generation can impact service reliability.

A. As Riverside's internal generating units age, there is an expectation that the operational performance will degrade over time. In particular, the older of Riverside's internal generating units – the four Springs units commissioned in July of 2003 – are facing the most challenge.

The Springs units are the first generation small peakers to which manufacturing and servicing have been discontinued by the manufacturer in the US. At present, there are no known available spare parts in the United States for the Springs generating units.

Because of this, Riverside has limited the operation of Springs in recent years only to dispatches required by the CAISO or in situations where Springs operation is necessary for reliability[31].

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[31] The Springs units annual operating hours were 58 hours, 77 hours, and 83 hours for 2015, 2016 and 2017 respectively, which equate to less than 0.5% annual

It is not realistic to assume that Riverside's internal generating units, and in particular the Springs units, can perform an increasingly larger role in relieving Vista overloading in the future as they age.

(a) Operational Design of RERC and Springs

Q. Please explain how the operational designs of RERC and Springs may limit their effectiveness to ensure service reliability.

A. Both RERC and Springs are designed to operate as peakers, i.e. for limited number of hours and starts each day to meet system peak load requirements[32]. They are not designed to operate potentially for an extended number of hours, which is expected to be required to address Vista overloading issues in the future as Riverside's load continues to grow, as well as under contingency conditions.

It is not realistic to expect that RERC and Springs can dependably operate beyond their operating design without any issues and perform an increasingly larger role in relieving Vista overloading in the future**.**

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capacity factor for each year. A significant portion of the annual operating hours for Springs in the last three years were due to mandated SCAQMD emissions testing.

[32] RERC operating permit limits operation of RERC 1 and 2 to approximately 1,200 hours per year or so on average, less than 4 hours per day. RERC 3 and 4 have slightly higher operating hours (approximately 1,800 per year) but are further limited in the number of starts each month to 40 starts. Both RERC 3 and 4 capped out of their monthly starts before month-end in October 2018, rendering them unavailable for the remainder of October 2018.

(b) Impact of Gas Availability Concerns on Existing Local Generation

Q. Please explain how gas availability may impact the ability of existing local generation to ensure service reliability.

A. Both RERC and Springs require natural gas to operate. Recently, the gas system in southern California operated by SoCal Gas has experienced constraints caused by Aliso Canyon[33] gas storage issues. Currently, a CPUC proceeding to determine the feasibility of minimizing or eliminating the use of Aliso Canyon is pending[34]. While Aliso Canyon has an operating capacity of 86 Bcf, it is currently only permitted to operate at a maximum of 34 Bcf,[35] or 28% of its capacity. It is not yet clear how the storage and gas supply capacity in southern California will be impacted moving forward.

As issues with Aliso Canyon linger on, there is a heightened probability of gas curtailments to electric generation within the SoCal Gas system, in particular electric generation located in the

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[33] In the aftermath of the October 23, 2015 leak, a moratorium on the Aliso Canyon Natural Gas Storage Facility was ordered. The facility has a capacity of 86 Bcf and 114 storage wells, but currently operates at a capacity of 34 Bcf.
[34] *See* Order Instituting Investigation 17-02-002.
[35] *Summary on the Operational Constraints at the Aliso Canyon Natural Gas Storage Facility*, California Public Utilities Commission, *available at*: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/AC.pdf.

southern California region[36]. If gas curtailments were to occur in the summer when the Riverside system peaks[37], it would severely limit Riverside's ability to use RERC and Spring in relieving the Vista overloading problem.

It is not realistic to expect that RERC and Springs can operate dependably in the same way as they have performed historically and assume an increasingly larger role in relieving the Vista overloading given the unsettled nature of the gas supply system due to continued restrictions on use of Aliso Canyon gas storage.

(c) Competing Operational Needs for Existing Internal Generation

Q. Are there other operational considerations that may limit the effectiveness of internal generation in ensuring service reliability?

A. Yes there are. There are competing operational needs for existing internal generation, in particular for the RERC units, that are worth mentioning.

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[36] Per SoCal Gas curtailment rules, gas consumption by the electric generation is the first to be curtailed during a system-wide gas emergency episode.

[37] Gas curtailment to Riverside's RERC units indeed has happened before. On February 20, 2018, SoCal Gas called a gas curtailment on its system due to system wide imbalance between supply and demand. At the time of gas curtailment, all four RERC units were supposed to be online to assist the CAISO to manage load ramping requirements but were unable to perform due to the gas curtailment. Had this incident occurred during the summer when Riverside system peaks, it would have caused significant overloading issues at Vista.

First, pursuant to the CAISO tariff provisions, Riverside as a load serving entity located in the CAISO balancing authority area is required to adhere to CAISO resource adequacy (RA) requirements in providing sufficient flexible generating capacity to the CAISO to enable the CAISO to operate the power grid reliably. Currently, Riverside designates RERC units as Riverside's flexible RA capacity to the CAISO in fulfillment of Riverside's RA obligations under the CAISO tariff[38]. Once designated as flexible RA capacity, each RERC unit must follow CAISO's dispatch instructions to generate power for the benefit of the entire CAISO grid, not just satisfy Riverside's power needs.

The fact that RERC units must follow CAISO's dispatch instructions creates a potential conflict with Riverside's need to use RERC units during high load conditions to relieve Vista loading.[39]

Recognizing this potential conflict, CAISO has granted a temporary variance to Riverside to allow Riverside to dispatch RERC units during Riverside's high load conditions[40] when

[38] RERC units are the generating units in Riverside's resource portfolio used to meet the majority of Riverside's flexible RA capacity obligations.
[39] Such conflict is the result of choices that CAISO may have to dispatch other cheaper generating units in lieu of dispatching RERC units at the time Riverside must use RERC units to relieve Vista loading.
[40] The high load condition is defined as any hour when Riverside's system load is expected to exceed 400 MW.

Riverside needs to dispatch RERC to relieve Vista loading without following CAISO's dispatch instructions.

This temporary variance was granted with the acknowledgement that Riverside is actively pursuing RTRP and that the variance will be rescinded once RTRP is built. In addition, CAISO has reserved the right to review the variance annually and modify/rescind the variance if CAISO deems necessary.

Second, during periods of low or moderate load when the variance does not apply, Riverside must follow CAISO's dispatch instructions for RERC.

In the past two years, Riverside has observed an increase in the dispatch of RERC units by the CAISO during the non-summer months when Riverside's load is low or moderate to meet CAISO grid needs.[41] As RERC units are only permitted to operate for a limited number of hours and starts each year by the South Coast Air Quality Management District (SCAQMD),[42] more use by the CAISO during the non-summer condition necessarily results in less

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[41] The ramping needs for the CAISO system has increased significantly in recent years as a result of a significant amount of intermittent renewable resources coming online in California. Peakers such as RERC units with fast ramping capability, are particularly suited to meet such ramping needs.

[42] Each RERC unit is currently permitted by the SCAQMD and SCAQMD places the following operating limits on RERC: Units 1&2 are limited to 1200 hours per rolling 12 month period, and Units 3 & 4 may run up to 1800 hours per rolling 12 month period, but Units 3 & 4 are limited to 40 starts per month and 225 hour/month limits.

hours for Riverside's use during the high load hours when Riverside needs RERC units to relieve Vista loading.

Given these two aspects of RERC operation, it is not realistic to expect that RERC can dependably operate in the same way it has performed historically and assume an increasingly larger role in relieving Vista loading in the future.

(d) Impact of State's GHG Reduction Goals on Long-Term Viability of Existing Local Generation

Q. Are there any restrictions that may impact the operation of the existing local generation in the future?

A. There likely will be restrictions related to GHG regulations. California's legislature and energy regulators have enacted increasingly stringent GHG reduction goals in the past ten years.

SB 100, enacted in the legislative year that ended in September 2018, established the State's goal to be free of GHG emitting electric generating sources by 2045. While Riverside currently meets the State's policy requirements on GHG reduction goals, both RERC and Springs generate GHG emissions in the power production process; in calendar year 2017, the GHG emission factors of RERC and Springs were 0.6344 metric ton of CO2e/MWh and 0.7247 metric tons of CO2e/MWh respectively.

In the long run, it is not realistic to expect that RERC and Springs can dependably operate in the same way they have performed historically and assume an increasingly larger role in relieving Vista loading given the increasingly stringent State GHG regulatory environment.

Q. What are the implications of the challenges listed above as to the ability of RERC and Springs to continue to provide relief to Vista loading when needed?

A. The implications are: (1) it is expected that RERC and Springs will be challenged to play an increasingly prominent role in providing the necessary relief to Vista loading problems in the future, and (2) this will make the Vista loading problem worse than it already is and makes the need for RTRP even more pressing and urgent.

Q. Are there any ancillary benefits to Riverside's internal generation that could be attributed to RTRP?

A Yes, ancillary benefits could be derived if RTRP is built.

First, it is conceivable that the gas consumption of Riverside's internal generation would decrease as they would no longer be needed to address the Vista loading issue during the high load conditions, thus alleviating Aliso Canyon's gas constraint and reducing GHG emissions.

Second, Riverside would have the flexibility and the ability to comply with the State's renewable energy and greenhouse gas reduction policy goals under SB 100 by eliminating the need to run Riverside's internal generation for local reliability purposes. Riverside takes pride in its long history of environmental stewardship and the progress it has made to date in meeting the State's climate and energy policy goals.

4. **Riverside's Sustainability Goals**

Q. Please explain Riverside's environmental stewardship and energy policy goals.

A. Riverside leans into establishing aspirational sustainability goals – in fact, in 2012, Riverside adopted a Green Action Plan and committed to increase the use of non-GHG emitting energy by 2020 to 50%, with at least 33% coming from renewable sources. As California regulations have extended the Renewable Portfolio Standard (RPS) requirements and established goals for GHG reductions to 2030 and beyond, Riverside continuously strives to achieve, and where possible exceed, State-mandated goals while ensuring safe, reliable and cost-effective electricity is available to our customers.

The RTRP is the means of having the flexibility and resiliency to meet customer needs and achieve long-term State goals.

Q. Why do you emphasize long-term State goals?

A. Because while RTRP is not necessary for Riverside to meet its GHG or RPS goals for 2030, after 2030, meeting the State's goals will become more difficult or impossible. With the passage of The 100 Percent Clean Energy Act of 2018 (Senate Bill 100), Riverside must also plan to serve its 100% retail sales of electricity with renewable energy sources and zero-carbon resources by the end of 2045. This goal will be impossible to meet without the second interconnection that would be provided by the RTRP.

Q. Why can't Riverside use local resources to meet the long-term GHG reduction goals?

A. While some local resources within Riverside's service territory may be an option, they will only be able to support a portion of the expected electricity needs. Not only would it be cost prohibitive to rely only on internal generation and local resources to provide reliable electricity to customers, it may also be impossible with currently known technologies due to lack of available land for large scale solar, wind, and energy storage projects. Further, if reliability became compromised, the lack of the RTRP could require Riverside to rely on GHG-emitting resources or push customers to install GHG-emitting resources such as back-up natural gas fuel cells or diesel generators to ensure access to reliable electricity.

Q. What does Riverside do now to promote Distributed Energy Resources, such as rooftop solar, distributed generation, energy storage, demand response and EE?

A. To provide local renewable power, Riverside actively promotes distributed energy resources (DERs) and continues to evaluate and explore innovative options to integrate these resources onto the distribution system. There is currently over 28 MW of installed rooftop solar PV on both commercial and residential buildings. Additionally, Riverside purchases power from a 7 MW solar facility on the location of the decommissioned Tequesquite landfill near downtown. This is an example of Riverside utilizing a city site not useable for other development to generate power locally. To manage the power fluctuations associated with these distributed energy systems, Riverside received a DOE grant and has installed micro-phaser technology to analyze and address the impacts of DERs on the distribution system, as well as to explore options for cost-effective energy storage technology at a local level. Additionally, in 2012, Riverside introduced a voluntary demand response program called Power Partners; this program encourages customers to agree to voluntarily shed or shift a specific amount of their energy use during peak demand times when requested from July through September. Finally, Riverside has established and is maintaining ambitious goals for energy efficiency – maintaining a goal of reducing energy consumption by 1% per year through 2030. This will help to manage the internal load growth by helping customers and their buildings be more energy efficient.

Q. Will these efforts enable Riverside to meet its and the State's climate goals?

A. Not on their own, no. While ambitious, these efforts are still not sufficient to provide electricity to the entire city and ensure electricity for the anticipated load growth as Riverside expands, becomes denser, and as electrification of both buildings and the transportation system occurs. To provide electricity in compliance with the State's climate goals, including future goal of 100% clean energy to Riverside reliably, the RTRP is necessary.

Q. Does Riverside plan to meet the State's climate goals?

A. Yes. Riverside expects to achieve the GHG reduction targets established by the State and has developed plans to achieve its share of the 2030 electric sector targets of both the 53 MMT GHG emissions target and the more aggressive 42 MMT GHG emissions target. To do this, Riverside will need to exceed the 2030 RPS goal and supply about 67% of Riverside's generation from emissions free resources. These resources will not be located within the Riverside service territory. The RTRP will ensure access to these renewable resources by providing the necessary redundant and expanded interconnection with the bulk power grid. After 2030, RTRP is necessary to achieve the goal of wholly serving customers carbon free electricity because of the reliance on resources outside of the service territory.

III. CONCLUSION

Q. Please summarize your conclusions regarding the need for RTRP.

A. The following conclusions confirm the need for RTRP:

1) The existing interconnection capability at Vista has been and will continue to be insufficient and inadequate to serve Riverside's load under normal and contingency operating conditions (N-0 and N-1);

2) The existing interconnection capability at Vista does not provide redundancy to avoid severe service interruptions to Riverside's customers when the Vista interconnection is unavailable; and

3) The challenges facing Riverside's local generation to mitigate Vista overloading will exacerbate the problem and further accentuate the inadequacy of the current Vista interconnection.

4) Therefore, RTRP is urgently needed to address the inadequacy of the existing Vista interconnection to ensure reliability of service to Riverside's customers.

Q. Are there any other issues related to RTRP that you wish to address?

A. RTRP is a complex undertaking that will require a delicate balance of many competing factors. Given the significant time and effort already undertaken to date toward RTRP and the demonstrated urgency for RTRP to ensure service reliability to Riverside, additional delays to allow consideration of additional project alternatives will present unacceptable reliability risks to Riverside. Therefore, the timeliness of implementation should be taken into consideration as one of the preponderant factors, in addition to cost and environmental impacts.

Q. Does this conclude Riverside's direct testimony?

A. Yes.

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APPENDICES

A **Single Line Diagram**

B **Summary of Seven 69 KV subtransmission lines from Vista**

C **2005 Facilities Study**

D **Riverside Internal Generation Dispatch Procedure**

E **Riverside Load Forecasting Methodology/Models/Assumptions**

F **SCE Data Response -SCE-003 Question 6(d) to Cal. Public**

Advocates, dated 1/27/2019

G **NERC Reliability Standard TPL-001-4**

H **Letters of Support from Critical Customers**

I **City Council Memorandum dated Dec. 7, 2004**

J **Witness Qualifications**

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I City Council Memorandum dated Dec. 7, 2004

J Witness Qualifications

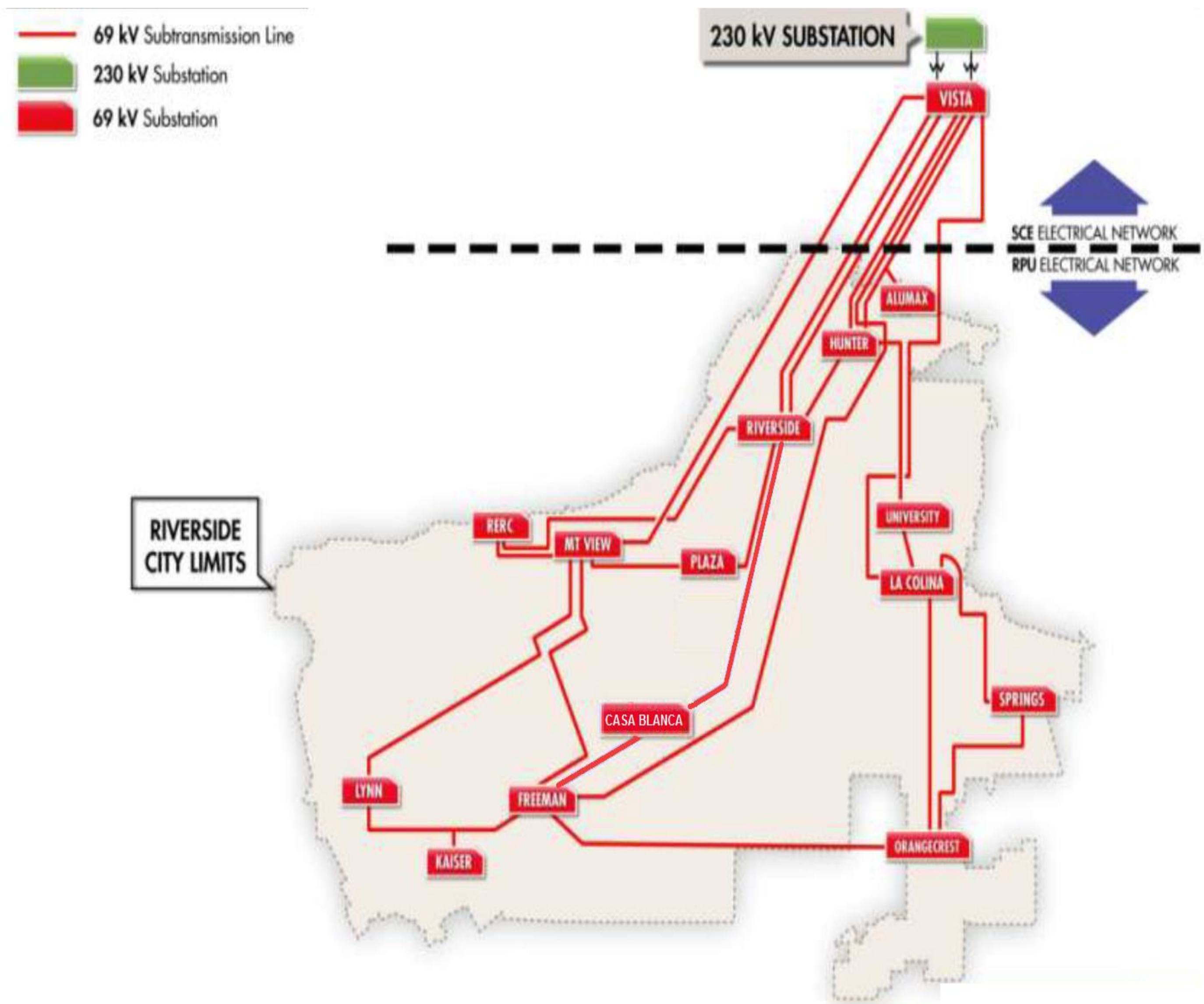
APPENDIX A

Single Line Diagram

APPENDIX A

SIMPLE ONE-LINE DIAGRAM

RIVERSIDE SUBTRANSMISSION LINES



APPENDIX B

Summary of Seven 69 KV subtransmission lines from Vista

APPENDIX B
VISTA SUBTRANSMISSION LINES SERVING RIVERSIDE

Riverside's Sub-transmission lines from SCE Vista station				
Sub-transmission Line	Normal Ampacity	Emergency Ampacity	Normal MVA	Emergency MVA
Vista-Alumax-Hunter	1000	1250	114	143
Vista-Hunter	1000	1250	114	143
Vista-La Colina	850	1060	97	121
Vista-Mt. View	850	1060	97	121
Vista-Riverside #1	1000	1250	114	143
Vista-Riverside #2	850	1060	97	121
Vista-University	850	1060	97	121

APPENDIX C

2005 Facilities Study

CITY OF RIVERSIDE TRANSMISSION INTERCONNECTION

JURUPA SUBSTATION

SOUTHERN CALIFORNIA EDISON COMPANY

FACILITIES STUDY

September 27, 2005

Prepared by:

Edgardo A. Romero

Approved by:

Charles E. Nieto

Southern California Edison

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I. Executive Summary

The City of Riverside (City) requested SCE to provide a 220kV Transmission Interconnection Facility to support the projected load growth to be served from a new substation to be owned, operated and maintained by the City. The new facilities will be will be located at the north / east corner of Wilderness Avenue and Ed Perkic Street in the City of Riverside.

The ownership of the facilities required to provide this service will be as follows:

- SCE will own the 220kV Transmission Lines and the Interconnection Facility.
- City will own the 220/66kV Transformer Banks and all 66kV facilities.

Currently, the City load is served from the 66kV System out of the SCE Vista 220/66kV Substation. The request for this study was made after SCE investigated the possibility of expanding Vista Substation to serve the increased City load and found several problems to satisfy the City projected load growth.

The new City of Riverside 220/66kV Substation will have a name-plate capacity of 560MW. The City has requested an interconnection date of January 1, 2008 to serve an initial load of 283MW.

NOTE:
The actual energization date will depend on the time required to obtain the required permits for the 8.5 miles of new transmission line required.
The attached Transmission Line Schedules show three different options with time frames ranging from two years to five years and three months.

SCE prepared a System Impact Study – Transmission Assessment dated June 7, 2005 to analyze the impact of the new interconnection to the SCE Transmission System. The System Impact Study is attached as Appendix A.

II. System Impact Study Results

The Study analyzed the following elements on the SCE System and arrived at the following conclusions:

• Load Flow Study:	No loading or voltage drops violations
• Post Transient Voltages Studies:	No post transient voltage violations
• Dynamic Stability Studies:	No frequency violations
• Short Circuit Studies:	No increases in S.C.D. of 0.1kA or more

The System Impact Study analyzed the following three possible transmission line arrangements to provide the transmission interconnection:

Option 1:

- Install a new SCE 220kV Interconnection Facility located adjacent to a new City 220/66kV Substation. The new facility will loop the existing SCE Mira Loma – Vista No.1 220kV Transmission Line and provide two points of service to the City.

Option 2:

- Install a new SCE 220kV Interconnection Facility located adjacent to a new City 220/66kV Substation, and two new SCE 220kV Transmission Lines, one from Mira Loma Sub. and one from Vista Sub. to the new facility. The new facility will terminate the two new lines and provide two points of service to the City.

Option 3:

- Install a new SCE 220kV Interconnection Facility located adjacent to the SCE Mira Loma – Vista No.1 220kV Right-of-Way, and two new 220kV Transmission Lines connecting the new facility to a new City of Riverside 220/66kV Substation. The new facility will loop the existing SCE Mira Loma – Vista No.1 220kV Transmission Line and provide two new 220kV Lines to the City.

The System Impact Study analyzed preliminary costs and selected Option 1 as the preferred alternative.

For the purpose of this Study, the SCE 220kV Interconnection Facility will be referred to as Jurupa Substation.

III. Facilities Study Scope

The Facilities Study identifies the scope of work and the cost estimate for the following work associated with the installation of the new SCE Jurupa Substation:

- Jurupa Substation: Install a new 220kV Interconnection Facility to loop the existing Mira Loma – Vista No.1 220kV Transmission Line and provide two points of service to a new City of Riverside 220/66kV Substation.
- Mira Loma Substation: Upgrade line protection on the existing Vista No.1 220kV Line Position. This line will become the Jurupa 220kV T/L.
- Vista Substation: Upgrade line protection on the existing Mira Loma No.1 220kV Line Position. This line will become the Jurupa 220kV T/L.
- Transmission Lines: Install 8.25 Miles of new Double Circuit 220kV Transmission Line from the existing Mira Loma – Vista 220kV Transmission Line Right-of-Way to Jurupa using 2-1033KCMIL ACSR Conductor.
- Telecommunications: Install new telecommunication circuit to Jurupa Substation to support the new line protection equipment.
- Power System Control: Install new Remote Terminal Unit (RTU) at Jurupa Substation

IV. Facility Study Scope – Additional Detail

A. Transmission:

Mira Loma – Vista No.1 220kV T/L
Engineer and construct approximately 8.25 Miles of new line constructed on double circuit tubular steel poles using 2-1033KCMIL ACSR Conductor and Optical Ground Wire to loop the line into the new Jurupa Substation.

This work requires the installation of approximately 550,000 Ft. of 1033KCMIL ACSR Conductor and 45,000 Ft. Optical Ground Wire.

This work also requires the installation of two single-circuit dead-end tubular steel poles to sectionalize the existing 220kV Transmission Line and a total of thirty-six suspension and twenty dead-end double-circuit tubular steel poles equipped with a total of two hundred and sixteen suspension and two-hundred and fifty-two dead end insulator assemblies.

B. Substation:

1. Jurupa Substation:
   Engineer and construct a 220kV Interconnection Facility with three positions arranged in a Breaker-and-a-Half configuration to terminate four lines. This facility will loop the Mira Loma – Vista No.1 220kV Transmission Lines and provide two 220kV Points of Service to the City of Riverside.

   The Interconnection Facility will be located adjacent to a new City of Riverside 220/66kV Substation.

   This work requires the installation of seven 220kV Circuit Breakers in two double-breaker line positions and one three-breaker position arranged in a "breaker and a half" configuration.

   The two lines serving the City will be equipped with Revenue Metering equipment.

2. Mira Loma Substation
   Upgrade the exiting Line Protection Relays on the Vista 220kV Line Position 5-N by replacing all existing relays as follows:

   Abandon existing relays and install one G.E. L90 and one SEL-311L Line Differential Relays and two G.E. C60 Breaker Management Relays.

   This Line will become the new Jurupa 220kV Transmission Line.

3. Vista Substation
   Upgrade the exiting Line Protection Relays on the Mira Loma 220kV Line Position 5-E by replacing all existing relays as follows:

   Abandon existing relays and install one G.E. L90 and one SEL-311L Line Differential Relays and two G.E. C60 Breaker Management Relays.

   This Line will become the new Jurupa 220kV Transmission Line.

C. Telecommunications:

Install two new taps and risers on the existing Mira Loma – Vista No.1 fiber wrap and tap one side to the new Optical Ground Wire of the new double circuit line connecting to Jurupa Substation.

Also install 65,000 Ft. of new Overhead Fiber Optic Cable on a separate route between Mira Loma and Jurupa Substations.
Both installations described above are required to form a new Mira Loma – Vista – Jurupa – Mira Loma closed fiber optic loop.

D. Metering Services Organization:

Engineer and prepare all required documentation to furnish, install and test two sets of revenue meters.

E. Power System Control:

Install a full size real-time RTU to monitor and control as follows:

- MW and MVAR on the incoming SCE Lines
- MW and MVAR on the outgoing City Lines
- Bus Voltage
- Circuit Breaker Status
- Circuit Beaker Control
- Protection Relays Status
- Alarms Status

F. Corporate Real Estate

Acquire Right-of-Way as needed for Jurupa Substation and the 8.25 Miles of Double Circuit Transmission Line.

G. Estimated cost: $70,004,000

See Appendix F for cost breakdown

V. Conclusions

A. The estimated costs for this project are approximately $70,004,000.

B. The time required to complete the proposed project will be between 24 and 63 months after receiving project authorization and funding, depending on the options available to acquire the necessary permits for the 8.5 miles of new transmission line. Refer to Appendix E for additional detail.

A detailed Substation Schedule is not shown because the Transmission Schedule controls the overall length of the Project.

C. The costs indicated in the attached tables are 2008 and are not firm. These are preliminary estimates only based on conceptual engineering and system unit costs, and are subject to change based on the final design and actual material costs. This Facilities Study and cost estimates as presented are valid for a period of 90 days.

D. The estimated Project Cost will be reconciled to actual costs upon closure of the subject work orders. The necessary billing adjustments will be made at that time.

APPENDIX A

SYSTEM IMPACT STUDY
TRANSMISSION ASSESSMENT

CITY OF RIVERSIDE
220 KV TRANSMISSION INTERCONNECTION

SYSTEM IMPACT STUDY
TRANSMISSION ASSESSMENT

June 07, 2005

EDISON

Prepared by

Sheridan Mascarenhas / Thanh Ninh

Southern California Edison Company

Patricia L Arons

CITY OF RIVERSIDE
220 KV TRANSMISSION INTERCONNECTION
TRANSMISSION INTERCONNECTION STUDY

EXECUTIVE SUMMARY

The City of Riverside applied to Southern California Edison (SCE) for a 220 kV Transmission Interconnection to SCE's Mira Loma-Vista 220 kV line. The request includes a new 220 kV substation called Jurupa, planned to be in service by January 1, 2008 to serve the increasing demand in the City of Riverside. The City of Riverside is currently being served by SCE's transmission system via the 220/66-kV Vista Substation. The City of Riverside also proposes to transfer six existing 66/12 kV substations from the Vista 66-kV system to the new substation.

The site for the new substation is located in the City of Riverside at the northeast corner of Wilderness Avenue and Ed Perkic Street. The City of Riverside proposes to sectionalize its retail load and serve approximately half of that load through the new substation. The remainder of the load will be served under an existing WDAT service provided by SCE thru Vista Substation. The projected load as per City of Riverside, for the year 2008 is estimated at 631 MW. The initial load for the new substation is 283 MW in 2008.

Findings and Conclusions

The assessment did not identify any significant problems with the requested transmission interconnection. Note that other line configurations were previously investigated and briefly discussed in the report.

Following is the scope for the facilities for direct interconnection of the Jurupa Substation.

Scope of Works for Facilities

- Engineer and construct a new 220 kV Interconnection Facilities called Jurupa Substation. Jurupa Substation shall have initial configuration of three 220 kV positions with seven breakers arrangement for two 220 kV lines and termination points for two 220/66 kV transformers. Note that the 220 kV bank Circuit Breakers shall be the interconnection point.
- Engineer and construct the looping of the existing Mira Loma-Vista # 1 220 kV line into Jurupa Substation, constructing 8.25 miles double circuit from Mira Loma-Vista T/L Right-of-Way to the Jurupa Substation
- Modify the existing protection schemes at Vista and Mira Loma Substation to accommodate the newly formed Mira Loma-Jurupa and Vista-Jurupa 220 kV lines.
- Develop the cost for the interconnection facilities

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THE CITY OF RIVERSIDE

220 KV TRANSMISSION INTERCONNECTION

TRANSMISSION INTERCONNECTION STUDY

INTRODUCTION

The City of Riverside (the City) applied to Southern California Edison for a Transmission Interconnection. The City proposes to obtain a 220 kV transmission level interconnection to serve a section of its retail load, by looping Edison's existing Mira Loma – Vista 220 kV line No. 1 through a new substation. By sectionalizing its retail load, the City plans to serve approximately half its retail load from the new substation on a firm basis. The remainder of the load is to be served under the existing WDAT service provided by Southern California Edison at Vista Substation.

The new 220/66-kV substation is planned to be in service by 2008. This area is currently being served by SCE's transmission system via the 220/66-kV Vista Substation. The proposed site for the new substation is located at the northeast corner of Wilderness Avenue and Ed Perkic Street, in the City of Riverside. This assessment was conducted to identify if there are any problems associated with the requested interconnection.

STUDY METHODOLOGY AND CONDITIONS

Planning Criteria

The study was conducted by applying the California Independent System Operator (CAISO) Reliability Criteria. More specifically, the main criteria applicable to this study are as follows:

The following contingencies are considered for transmission and 500/220 kV transformer banks ("AA-Bank"):

Assuming the largest unit (San Onofre Unit 2 or 3) initially off and then:

- Single Contingencies (loss of one line or one AA-Bank)

Assuming both San Onofre Units 2 and 3 in service and then:

- Single Contingencies (N-1 Line or N-1 AA-Bank)
- Double Contingencies (N-2 Two Lines, N-1 Line and N-1 AA-Bank) (Outages of two AA-Banks are beyond the Planning Criteria)

The following criteria are used:

Transmission Lines	Base Case	Limiting Component Normal Rating
	N-1	Limiting Component A-Rating
	N-2	Limiting Component B-Rating
500-220 kV Transformer Banks	Base Case	Normal Loading Rating
	Long & Short Term	As Defined by SCE Operating Bulletins

Note that violation of above criteria could require system upgrades.

System Load Forecast

Loads used within the SCE system reflect a coincident peak load for 1-in-10 year heat wave conditions. The forecast for the Vista system is shown in the table below. Light Spring loads were obtained by using 65% of the Heavy Summer load forecast. Autumn and spring seasons have historically been the times when EOR/WOR flow is the highest going from east to west, which is also the most critical scenario for the transmission west of Devers path.

Coincident A-Bank Load Forecast (MW)	
Substation Load (1 in 10 Year Heat Wave)	
SUBSTATION	2008
Vista 66 kV	474
Jurupa 66 kV	283

SCE Area Loads & Resources

The system conditions for SCE area for 2008 are as follows:

	2008 (MW)			
	Heavy Generation & Light Load		Heavy Load & Light Generation	
Load & Resources	Light Spring (Pre)	Light Spring (Post)	Heavy Summer (Pre)	Heavy Summer (Post)
Import	7086	7086	9122	9122
Generation	8718	8715	15047	15326
Load	15327	15327	23580	2856
Losses	475	475	589	592

Studies Performed

Performed load flow, post-transient, and dynamic simulation studies.

STUDY RESULTS for Interconnection of Jurupa Sub.– DISCUSSION

Load Flow Study

There were no loading or voltage drop violations attributed to, or impacted by the Jurupa Substation Project.

Major Path Power Flows

The results of power flows for the 2008 Light Spring and Heavy Summer scenarios are as follows:

Major Paths Power Flows	2008 FLOW (MW) (Stressed WOR/EOR)			
	Light Spring		Heavy Summer	
	Pre-project	*Post-project*	*Pre-project*	*Post-project*
Mira Loma – Vista 220 kV No. 1	-732	---	-47	---
Mira Loma-Jurupa 220 kV	---	-414	---	40
Jurupa-Vista 220 kV	---	-510	---	142
Mira Loma – Vista 220 kV No. 2	-511	-622	107	75

Post Transient Voltage Studies

No post transient voltage violations were found that was attributable or impacted by the Jurupa Substation project.

Dynamic Stability Studies

No frequency violations were identified that was attributable or impacted by the Jurupa Substation project.

Short Circuit Study Results

No short circuit violations were found that was attributable or impacted by the Jurupa Substation project.

Scope of Works for Interconnection of Jurupa sub.

- Engineer and construct a new 220 kV Interconnection Facilities called Jurupa Substation. Jurupa Substation shall have a standard configuration of three 220 kV positions with seven breakers arrangement for two 220 kV lines and two termination points for 220/66 kV transformers. 220 kV bank Circuit Breakers shall be the interconnection point.
- Engineer and construct the looping of the existing Mira Loma-Vista # 1 220 kV line into Jurupa Substation, constructing 8.25 miles double circuit from Mira Loma-Vista T/L Right-of-Way to the Jurupa Substation
- Modify the existing protection schemes at Vista and Mira Loma Substation to accommodate the newly formed Mira Loma-Jurupa and Vista-Jurupa 220 kV lines.
- Develop cost estimates and schedules for the interconnection facilities

Alternative Line and Substation configurations

Previous Studies evaluated a number of alternatives for the transmission lines and substation configurations:

a) The requested interconnection referred to as Option 1, formed by looping in the existing SCE Mira Loma-Vista 220 kV line No.1 through the new Jurupa Substation. The proposed loop in, as per the City, is diagramed in Appendix A.

b) Two other line configurations were considered (Option 2), which entailed two additional 220 kV transmission lines to be built from both, Mira Loma and Vista substations to the new Jurupa substation. However Option 2 proved to be disproportionately expensive and not a feasible option due to the physical limitation at the Vista 220 kV bus. The third option (Option 3), considered the possibility of building another new substation in-between the Mira Loma and Vista substations. This new substation would then serve the City's new Jurupa substation. This option was also disproportionately expensive and therefore the preferred line configuration was the City's proposal of looping in the existing Mira Loma – Vista 220 kV line into the City's new Jurupa Substation.

Cost Estimate Comparison

Options	*Costs*	*Remarks*
Option I: Loop-in the existing Mira Loma-Vista # 1 220 kV into Jurupa 220	38.0 Million	Includes 220 Interconnection facility at Jurupa Substation
Option II: Build new 220 kV lines from Vista and Mira Loma to Jurupa Substation	-----	Not a feasible Option due to physical limitation on the Vista 220 kV bus
Option III: Build new interconnection Facility adjacent to Mira Loma-Vista T/L Right-of-Way	52.0 Million	includes 220 interconnection facility ($ 16.0 Million), 8.25 Miles 230 kV double circuit (approx. $ 20.0 Million) and Jurupa 230 kV (approx. $ 16.0 Million)

Findings and Conclusions

There were no problems identified with the requested interconnection. The project can proceed to the Facilities Studies for the direct interconnection of Jurupa Substation.

RECOMMENDATION

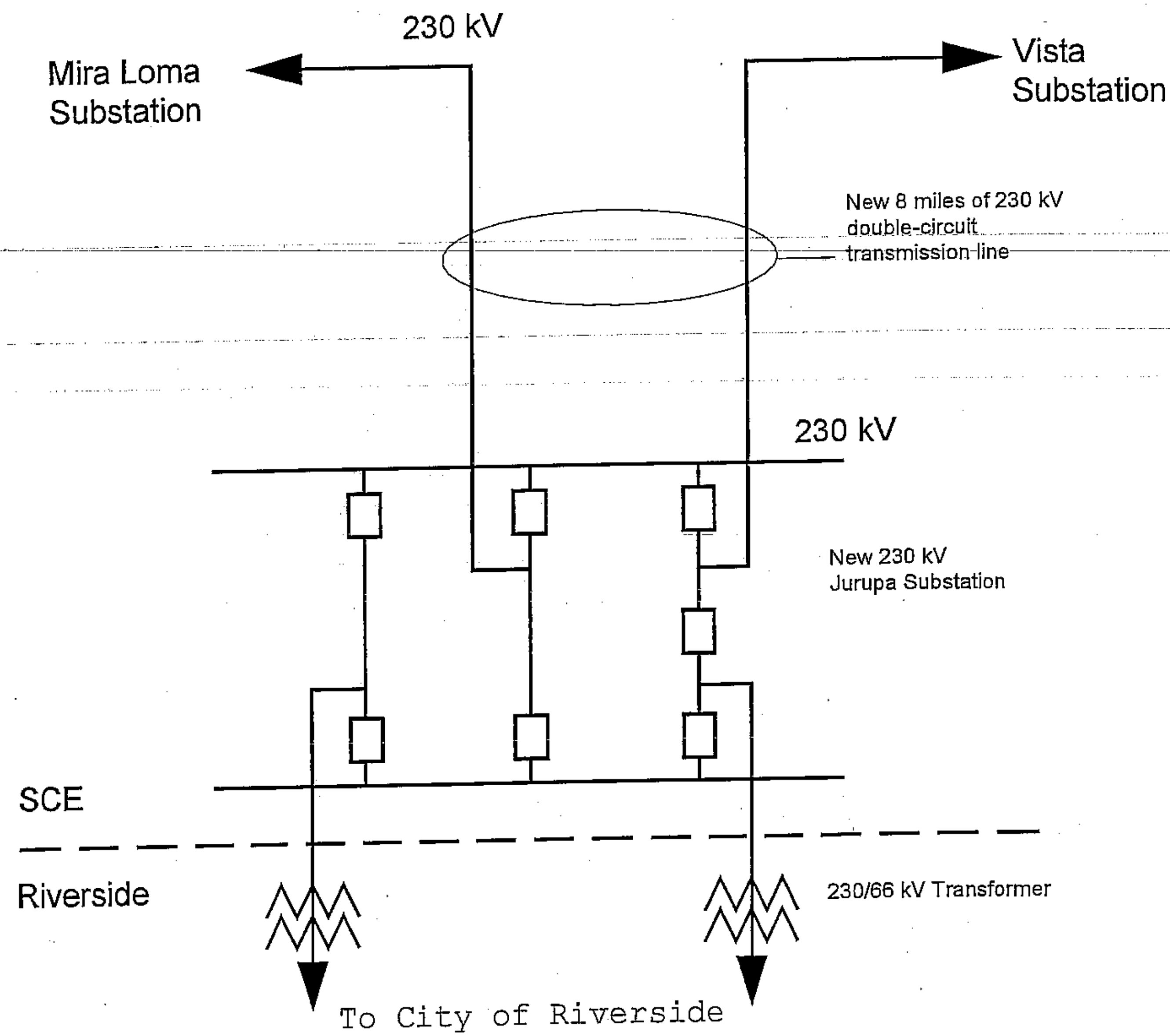
Option 1 details the loop-in of the Mira Loma – Vista 220 kV line #1 into the new Jurupa Substation is the recommended method of service in 2008. This option is consistent with SCE's planning practices to address load growth in the area. The option provides adequate reliability to serve the City of Riverside and is also the most economically feasible alternative.

Edison's design criteria call for transformers to be terminated on circuit breakers and not directly terminated at the bus. Therefore, the single line diagram submitted by The City of Riverside needs to be modified so that the 220/66 kV transformers will be terminated on circuit breakers as shown in Appendix A – Option 1.

APPENDIX A

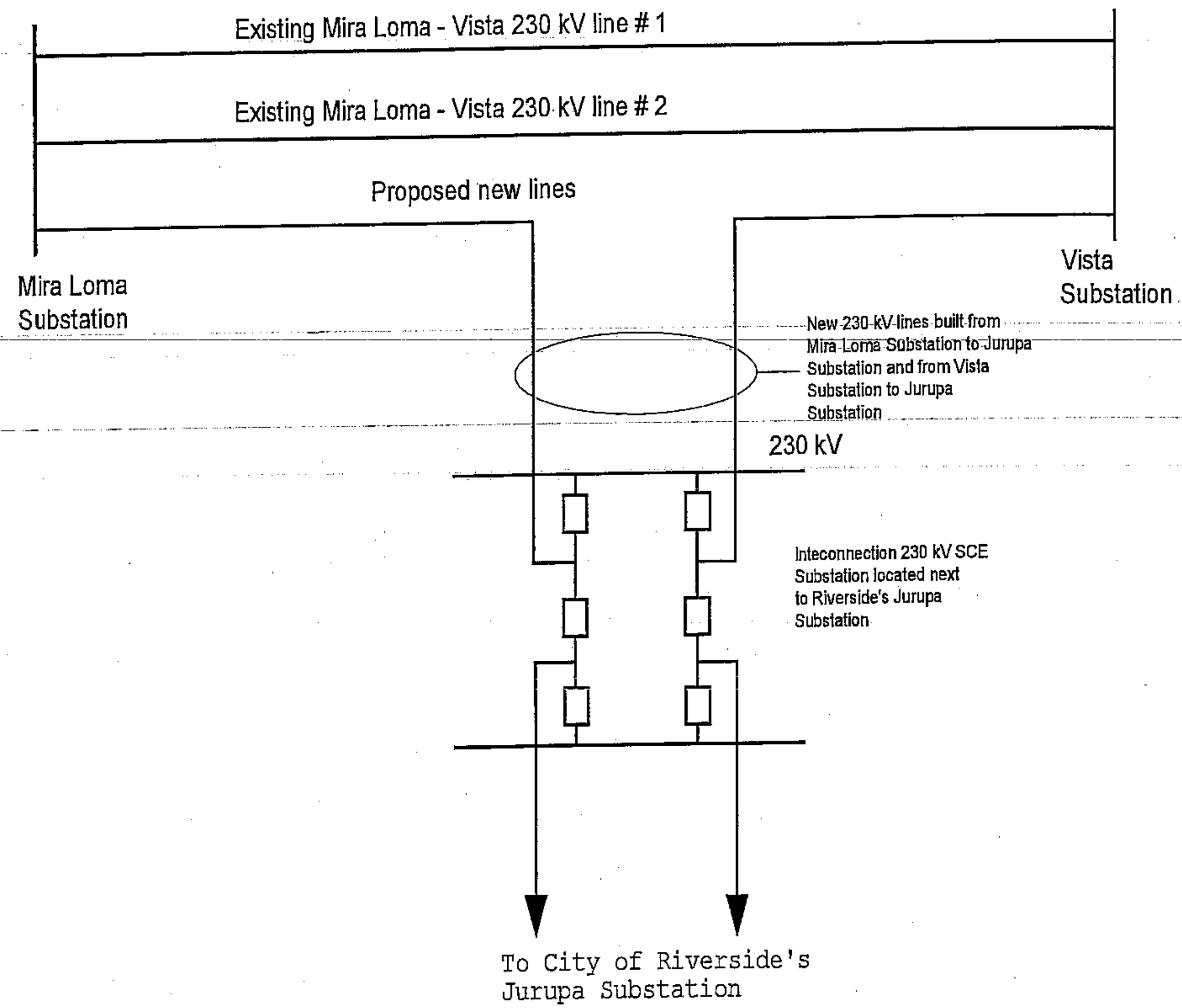
SINGLE LINE DIAGRAM – Option 1

Possible 220 kV Transmission Interconnection between City of Riverside and Southern California Edison



SINGLE LINE DIAGRAM – Option 2

Possible 220 kV Transmission Interconnection between City of Riverside and Southern California Edison



SINGLE LINE DIAGRAM – Option 3

Possible 220 kV Transmission Interconnection between City of Riverside and Southern California Edison

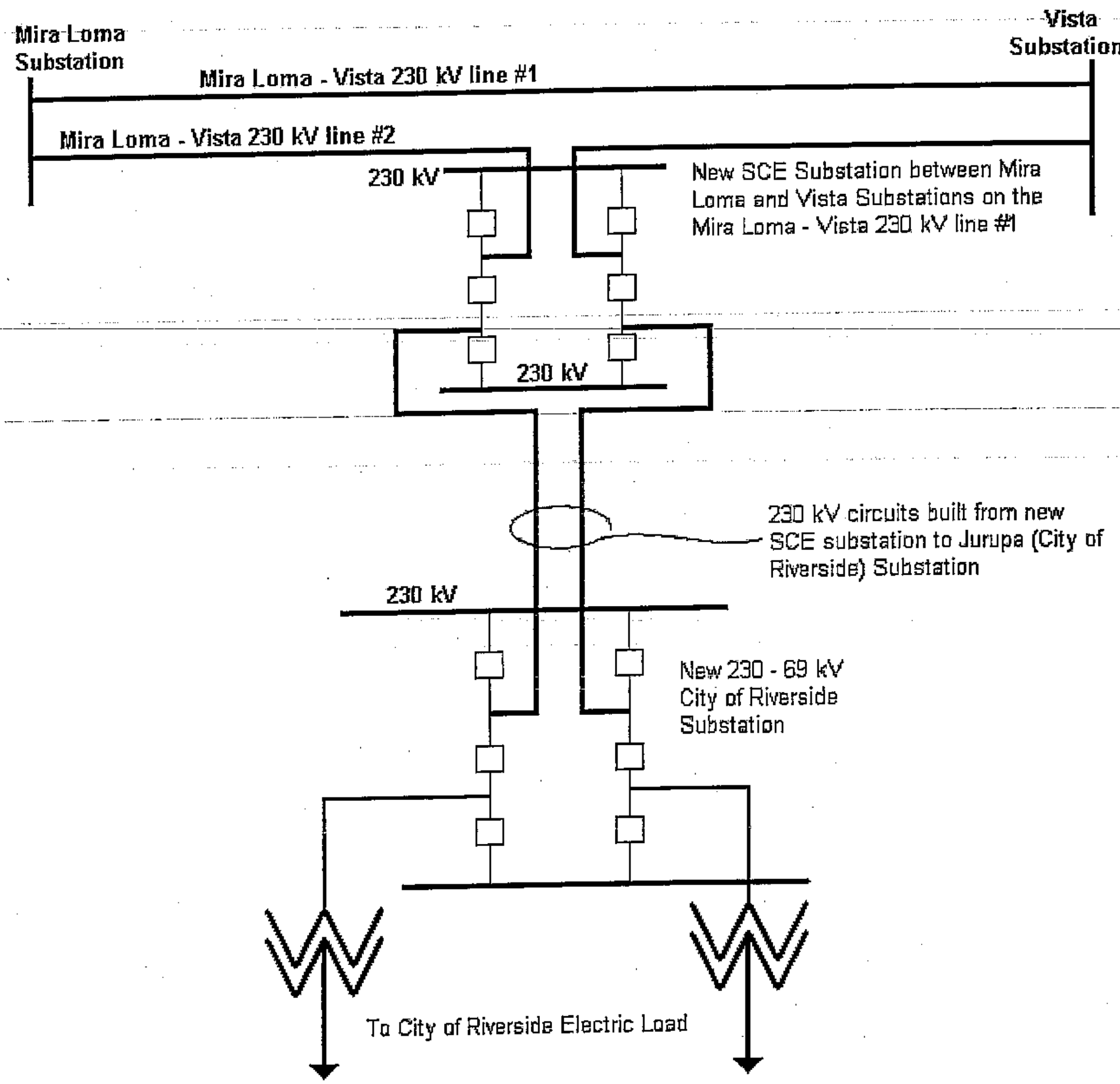
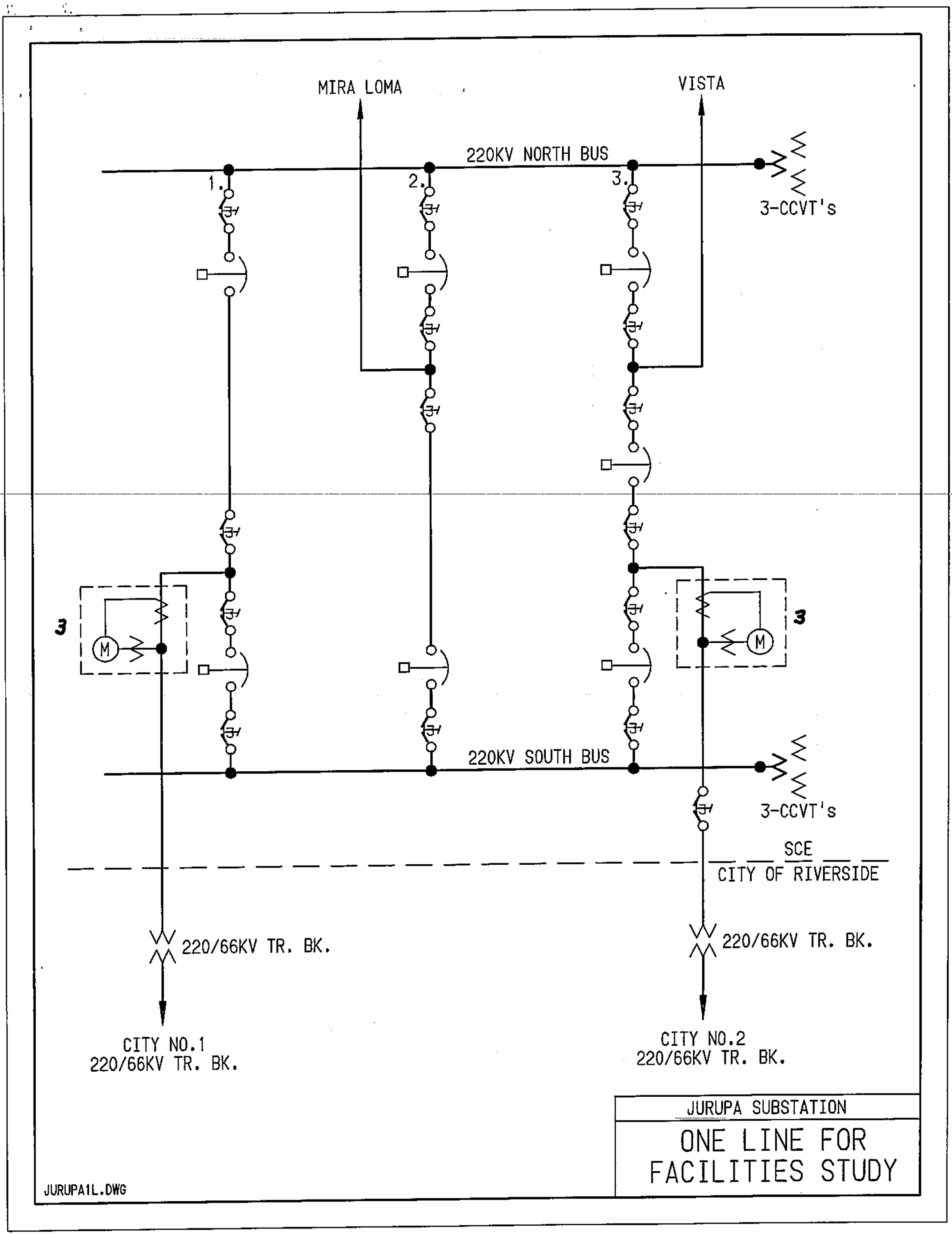
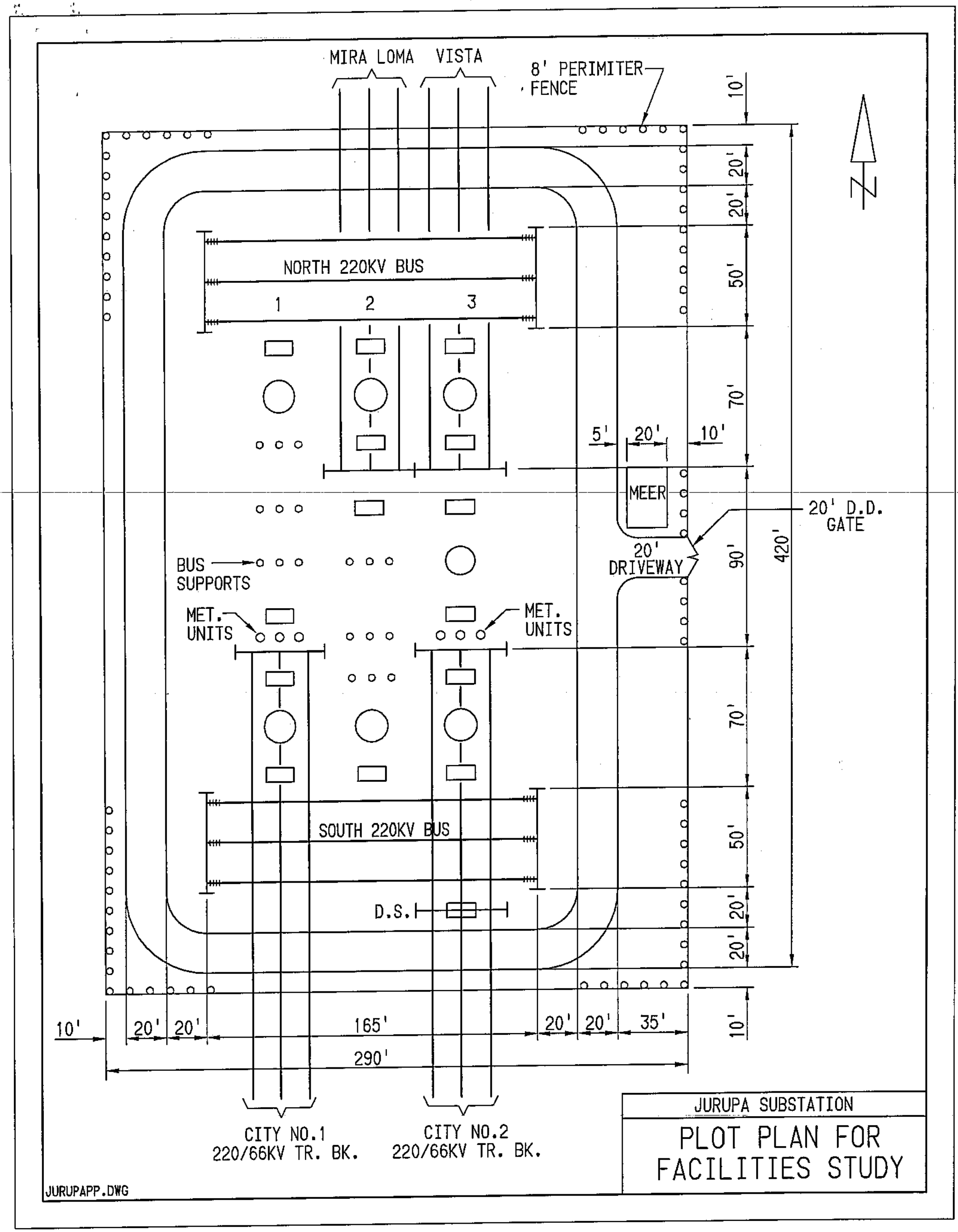


EXHIBIT B

JURUPA SUBSTATION
ONE LINE AND PLOT PLAN

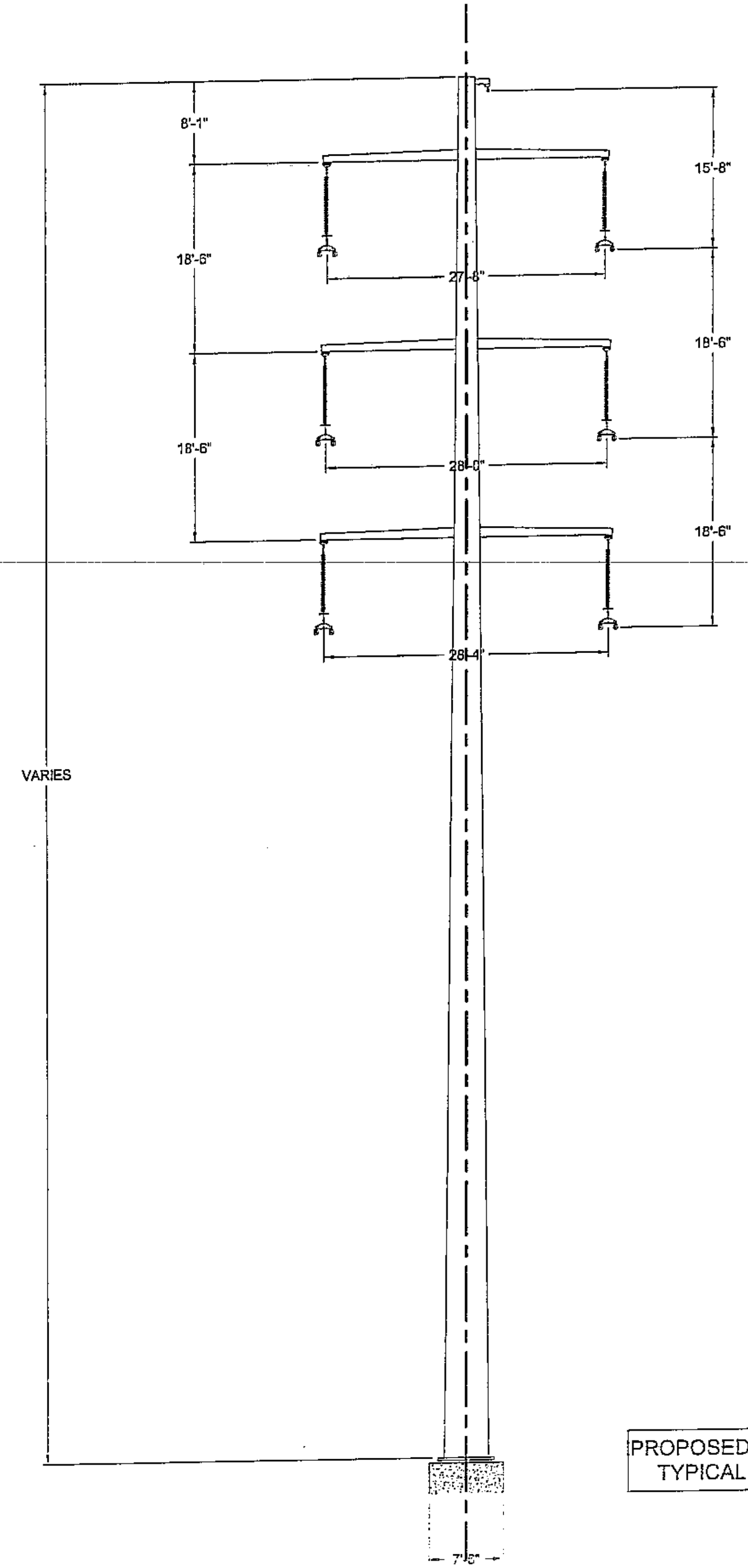

MIRA LOMA
VISTA
220KV NORTH BUS
1.
2.
3.
3-CCVT's
3
M
3
M
220KV SOUTH BUS
3-CCVT's
SCE
CITY OF RIVERSIDE
220/66KV TR. BK.
220/66KV TR. BK.
CITY NO.1
220/66KV TR. BK.
CITY NO.2
220/66KV TR. BK.
JURUPA SUBSTATION
ONE LINE FOR
FACILITIES STUDY
JURUPA1L.DWG



MIRA LOMA
VISTA
8' PERIMITER FENCE
NORTH 220KV BUS
1
2
3
5'
20'
10'
MEER
20' D.D. GATE
20' DRIVEWAY
BUS SUPPORTS
MET. UNITS
MET. UNITS
SOUTH 220KV BUS
D.S.
10'
20'
20'
50'
70'
90'
420'
70'
50'
20'
20'
10'
10'
20'
20'
165'
20'
20'
35'
290'
CITY NO.1
220/66KV TR. BK.
CITY NO.2
220/66KV TR. BK.
JURUPA SUBSTATION
PLOT PLAN FOR
FACILITIES STUDY
JURUPAPP.DWG

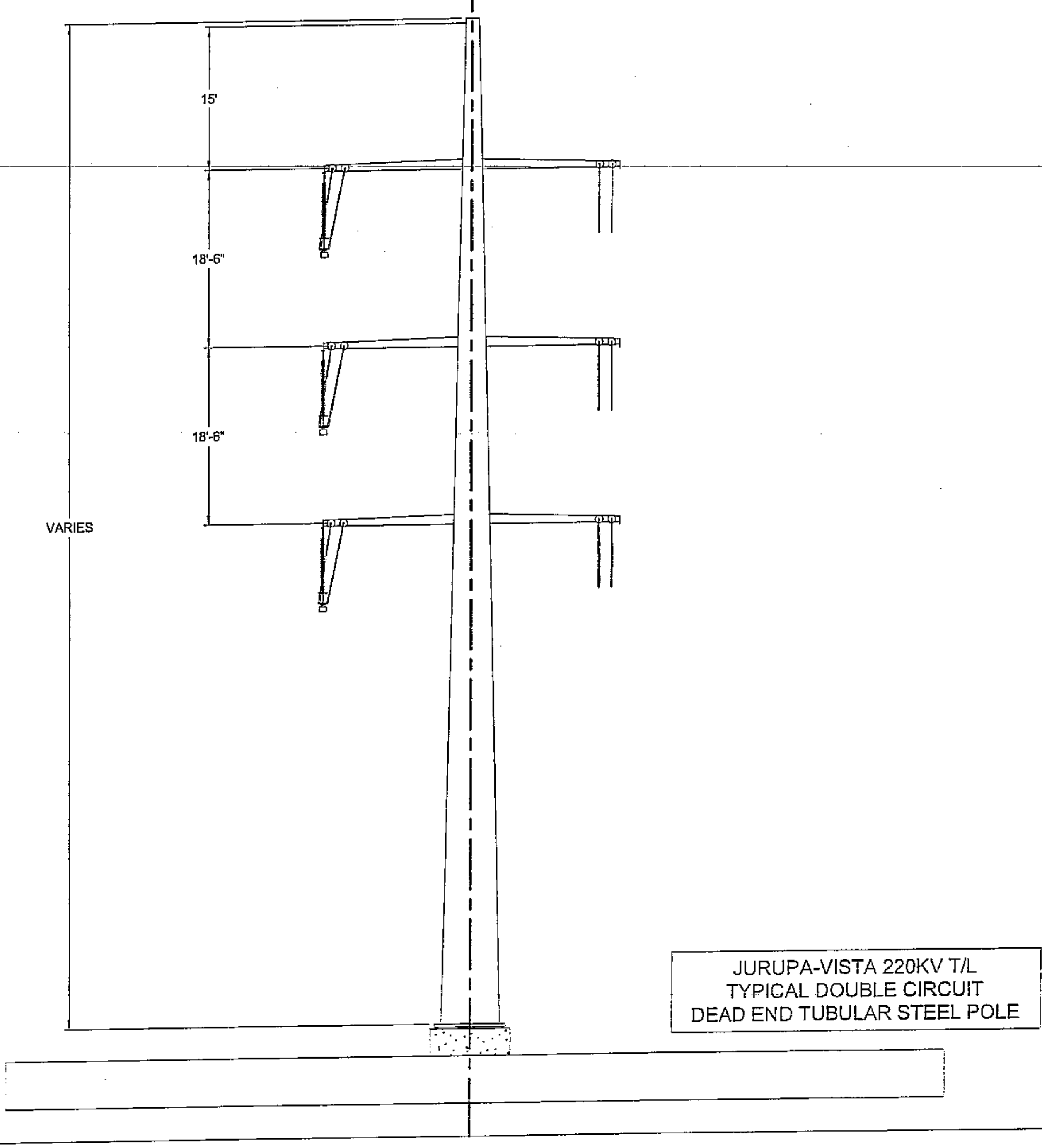
APPENDIX C

TYPICAL 220kV DOUBLE CIRCUIT TRANSMISSION STRUCTURES



PROPOSED JURUPA-VISTA 230KV T/L
TYPICAL TUBULAR STEEL POLE

Double Circuit Dead End Pole



APPENDIX D

MAJOR EQUIPMENT AND RELAYS

CITY OF RIVERSIDE TRANSMISSION INTERCONNECTION
MAJOR EQUIPMENT and RELAYS

SUBSTATIONS:

JURUPA SUBSTATION:

7	220kV 3000A 63kA Circuit Breakers
15	220kV Group Operated - Horizontally Mounted Disconnect Switches
12	220kV Coupling Capacitor Voltage Transformers
42	220kV Bus Supports
4	220kV Line Dead-End Structures
4	220kV Bus Dead-End Structures
12	G.E. PVD21D Bus Differential Relays
2	G.E. L90 Line Current Differential Relays – SCE Lines
2	Schweitzer SEL-311L Line Current Differential Relays – SCE Lines
7	G.E. C60 Breaker Management Relays – One for each CB
1	DFR 32/64 Channels
2	Revenue Metering Cabinets
1	Mechanical – Electrical Equipment Room (MEER)

MIRA LOMA SUBSTATION

1	Schweitzer SEL-352 Breaker Failure Relay
1	G.E. L90 Line Current Differential Relay
1	Schweitzer SEL-311L Line Current Differential Relay

VISTA SUBSTATION

1	G.E. C60 Breaker Management Relay
1	G.E. L90 Line Current Differential Relay
1	Schweitzer SEL-311L Line Current Differential Relay

CITY OF RIVERSIDE TRANSMISSION INTERCONNECTION
MAJOR EQUIPMENT and RELAYS

TRANSMISSION:

2	Dead-End Single Circuit Tubular Steel Poles
36	Suspension Double Circuit Tubular Steel Poles
20	Dead-End Double Circuit Tubular Steel Poles
216	Suspension Insulator/Hardware Assemblies
252	Dead End Insulator/Hardware Assemblies
120	Swing Insulator / Hardware Assemblies for Dead End Poles
550,000 Ft.	1033KCMIL ACSR Conductor
45,000 Ft.	Fiber Optic O.P.G.W.

TELECOMMUNICATIONS:

65,000 Ft.	Fiber Optic Telecommunications Overhead Cable

POWER SYSTEM CONTROL:

1	Remote Terminal Unit (RTU)

E. A. ROMERO - 09/21/05

APPENDIX E

TRANSMISSION LINE PROJECT SCHEDULE

Riverside Public Utility
Proposed 220kV Interconnection
Project Schedules

New 220kV Transmission Line Ideal Schedule in Developed Area

		YEAR 1				YEAR 2				YEAR 3				YEAR 4				YEAR 5				YEAR 6			
		Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4
Public Outreach/Siting & Route Selection	1 year																								
Environmental Studies	1 year																								
CPCN Submittal to Decision	15 mo.																								
Real Estate Acquisitions & Permits	1 year																								
Engineering	As Needed																								
Procurement	9 mo																								
Construction	1 year																								

Total Time: 5.25 years

New 220kV Transmission Line Expedited Schedule in Developed Area

		YEAR 1				YEAR 2				YEAR 3				YEAR 4				YEAR 5			
		Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4
Public Outreach/Siting & Route Selection	1 year																				
Environmental Studies	1 year																				
CPCN Submittal to Decision	15 mo.																				
Real Estate Acquisitions & Permits	1 year																				
Engineering	As Needed																				
Procurement	9 mo																				
Construction	1 year																				

Total Time: 4.25 years

New 220kV Transmission Line Expedited Schedule After Official Approval (Assumes no final funds before start date)

		YEAR 1				YEAR 2			
		Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4
Engineering	As Needed								
Real Estate Acquisitions & Permits	1 year								
Procurement	9 mo								
Construction	1 year								

Total Time: 2.00 years

C. Meissner
9/10/2005

APPENDIX F

COST SUMMARY

CITY OF RIVERSIDE TRANSMISSION INTERCONNECTION

Cost Estimate Summary (2008 Dollars)

Scope: Install a new 220kV Interconnection Facility to provide two-line service to a new City-owned Substation

ELEMENT	INTERCONNECTION FACILITIES Subject to O&M	Income Tax Component of Contribution *	ONE TIME COST **	ONE TIME PAYMENT
Jurupa Substation - New Interconnection Facility	$ 7,705,000	$ 2,697,000	$ 2,359,000	$ 12,761,000
Mira Loma Substation - Protection Upgrades	$ 180,000	$ 63,000		$ 243,000
Vista Substation - Protection Upgrades	$ 216,000	$ 76,000		$ 292,000
Transmission Line (Loop into Jurupa Sub.)	$ 20,794,000	$ 7,278,000	$ -	$ 28,072,000
Telecommunications - Line Protection & RTU	$ 895,000	$ 313,000	$ -	$ 1,208,000
Metering Services Organization	$ 21,000	$ 7,000		$ 28,000
Power System Control	$ 80,000	$ 28,000	$ -	$ 108,000
Corporate Real Estate	$ 20,216,000	$ 7,076,000	$ -	$ 27,292,000
TOTAL	**$ 50,107,000**	**$ 17,538,000**	**$ 2,359,000**	**$ 70,004,000**

This document includes confidential trade secrets and proprietary information of Southern California Edison, to be used only by the City of Riverside in connection with its evaluation of this Facility Study Proposal. Southern California Edison retains all rights to maintain the confidentiality of this information and requests that the City of Riverside preserve its confidentiality.

* ITCC tax (calculated at 35 %) on all elements associated with the Interconnection Facilities.

** Cost of subsurface work. At the option of the customer, SCE may perform the subsurface work on a one-time collectible ba:

E. A. ROMERO - 09/21/05

APPENDIX D

Riverside Internal Generation Dispatch Procedure

APPENDIX D

Riverside Local Reliability
Internal Generating Units Dispatch Procedure
Version 1 – July 14, 2015

Table of Contents

1. PURPOSE

This procedure memorializes the advisory and mandatory actions performed by Riverside Public Utilities (RPU) Energy Delivery operational dispatchers and Power Resources schedulers in the utilization of Riverside's internal generating units to serve RPU's retail load cost effectively while maintaining the reliability of RPU's distribution system. Such actions have been in place for some time and are all in fulfillment of the purpose of building generating units within RPU's distribution system to provide reliable and affordable electric services to RPU's customers. This procedure memorializes such historical practices.

Currently, RPU has a single point of interconnection with Southern California Edison Company (SCE) at SCE's Vista Substation. There are two 220/66 kV power transformers and seven 66 kV subtransmission power lines out of the Vista Substation dedicated to RPU. SCE has the ownership of the two 220/66 kV power transformers and the line of demarcation of the ownership of the seven 66 kV subtransmission lines is at City of Riverside's city boundaries.

The two 220/66 kV power transformers have a planned load limit of 308 MVA and a 1-hour short term emergency load limit of 448 MVA.

In addition, Springs generating units are dispatched in order to maintain electric voltage within appropriate limits under certain high load conditions in localized areas within RPU's distribution system.

The operation of Riverside's internal generating units -four GE LM6000 simple cycle peaking generating units at Riverside Energy Resource Center (RERC) and four GE 10B combustion turbines at Springs Generating Station (Springs) - is driven by the need to serve RPU's retail load reliably and cost effectively.

Since 2004, RPU has been planning to mitigate the limitations of Vista transformer bank capability as well as internal distribution contingencies that require the dispatch of RPU's internal generating units. The Riverside Transmission Reliability Project (RTRP) that RPU is undertaking with SCE will substantially mitigate such limitations and contingencies. RTRP will provide a second source of power from the transmission grid from SCE's Mira Loma Substation via a loop-in transmission line to the existing SCE's Vista-Mira Loma line #1 to the new SCE's Wildlife Substation to be constructed as part of the RTRP.

On June 14, 2006 the CAISO Board of Governors approved the RTRP and directed SCE to build the interconnection as soon as possible and preferably no later than June 30, 2009.

Only recently SCE has filed the Certificate for Public Convenience and Necessity (CPCN) for the RTRP with the California Public Utilities Commission (CPUC) in April, 201S and RTRP is not expected to be in-service until 2019 at the earliest. Until RTRP is in service, RPU must continue to rely on this procedure to maintain local reliability during high load conditions.

The economic consideration predominates the dispatch decisions of Riverside internal generating units when RPU's retail load is moderate, while reliability consideration will predominate the dispatch decisions when RPU's retail load is high.

This procedure provides the guidelines to the Energy Delivery operational dispatchers and Power Resources schedulers for the effective utilization of Riverside's internal generating units.

2. RESPONSIBILITIES

2.1 - Energy Delivery Operational Dispatchers

- Provide accurate information and timely consult with Power Resources schedulers, RERC and Springs generation operators of dispatch decisions given RPU's distribution system conditions
- Direct Power Resources schedulers to dispatch RERC and Springs generating units to maintain system operating parameters within acceptable reliability margins in accordance with the applicable RPU reliability planning criteria

2.2 - Power Resources Schedulers

- Timely consult with Energy Delivery operational dispatchers, RERC and Springs generation operators on RERC and Springs generating units dispatch decisions
- Serves as the RPU's interface with California Independent System Operator (CAISO) for the operation of RERC and Springs generating units
- Coordinate the implement of RERC and Springs generating units dispatches with Energy Delivery operational dispatchers, RERC and Springs generation operators

2.3 – RERC and Springs Generation Operators

- Provide accurate and timely information to Power Resources schedulers and Energy Delivery operational dispatchers regarding the status of RERC and Springs generating units
- Consult and coordinate with Energy Delivery operational dispatchers and engineers and Power Resources schedulers on planned RERC and Springs generating unit outages

- Coordinate and implement the RERC and Springs generating units dispatches with Energy Delivery operational dispatchers and Power Resources schedulers

2.4 – Energy Delivery Engineers

- Maintain and timely update planning and operational studies affecting the RERC and Springs generation units dispatches in accordance with applicable RPU reliability planning criteria
- Communicate relevant planning information/parameters to Energy Delivery operational dispatchers, RERC and Springs generation operators and Power Resources schedulers in aid of RERC and Springs generating units dispatch decisions

3. <u>Procedure Detail</u>

3.1 – Energy Delivery Operational Dispatchers Actions

Step 1 – Issue advisory and mandatory RERC and Springs generating units dispatch orders to Power Resources schedulers as follow:

- Advisory (Day-ahead) – Reserve all RERC and Springs generating units for RPU's use when RPU's Vista load is anticipated to exceed 400 MW. This is to ensure RPU's distribution system and load serving reliability can be maintained in case of an N-1 contingency of Vista power transformers. As RPU's distribution system operating conditions permit, coordinate with Power Resources schedulers to participate in the CAISO markets in accordance with CAISO operating and market protocols.

- Mandatory (Day-ahead) - In addition to reserving all RERC and Springs generation units, if RPU's Vista load is anticipated to exceed 500 MW, further actions will be required to avoid overloads of SCE's Vista power transformers and loss of RPU's load due to contingencies within RPU's distribution system. Such action includes bringing a minimum amount of generating units online as follows:

  500 MW RPU's load at Vista ------------ One RERC generating unit online (minimum)

  540 MW RPU's load at Vista ------------ Two RERC generating units online (minimum)

  575 MW RPU's load at Vista ----------- Four RERC generating units online (minimum)

  The amount of Riverside's internal generating units that must be online in high load conditions is the minimum amount. The Energy Delivery operational dispatchers shall determine the actual amount of Riverside internal generating units that must be online (not less than the minimum amount) based on the actual assessment of the system conditions at the time of dispatch.

- Mandatory (Any Time) – Upon occurrence of a contingency or a system emergency within RPU's distribution system, promptly issue dispatch instructions to Power Resources schedulers to dispatch RERC and Springs generating units.

3.2 – Power Resources Schedulers Actions

Step 1 – If RPU's Vista load is anticipated to be less than 400 MW on a day-ahead basis, coordinate the dispatch of Riverside's internal generating units with RERC and Springs generation operators economically and consistent with CAISO dispatch instructions.

Step 2 – If RPU's Vista load is anticipated to be greater than 400 MW on a day-ahead basis, follow the advisory and mandatory dispatch orders from Energy Delivery operational dispatchers and coordinate with RERC and Springs generation operators to implement the dispatch orders. As RPU's distribution system operating conditions permit and at the discretion of the schedulers, coordinate with Energy Delivery operational dispatchers, RERC and Springs generation operators to participate in the CAISO markets in accordance with CAISO operating and market protocols.

Step 3 – Communicate CAISO grid emergencies and coordinate with Energy Delivery operational dispatchers, RERC and Springs generation operators to effect assistance (if requested) to the CAISO by dispatching Riverside's internal generating units consistent with the applicable CAISO agreements and tariffs.

3.3 – RERC and Springs Generation Operators Actions

Step 1 – Communicate the status of RERC and Springs generating units to Energy Delivery operational dispatchers and Power Resources schedulers at all times.

Step 2 - Follow the advisory and mandatory dispatch orders as issued by Energy Delivery operational dispatchers via Power Resources schedulers.

4. <u>Supporting Information</u>

References:

- SCE's SOB 32 – Loss of A/AA Bank Overload Protection
- SCE's SOB 33 – Re-Energizing Bulk Power and Generator Transformers after a Relay Operation
- Internal technical studies establishing the minimum RERC generating units must-run status for high load conditions
- Amended and Restated Metered Subsystem Agreement between City of Riverside and CAISO

5. Periodic Review Procedure

This procedure and the related technical studies shall be reviewed and updated as applicable on an annual basis.

6. Effectiveness

This procedure is effective as of this date of July 14, 2015 and supersedes Riverside Energy Resource Center (RERC) Generating Units – Operational Dispatch Procedure – Version 2 – June 16, 2015 in its entirety.

Approval:

	Signature
Energy Delivery – Engineering Manager	
Energy Delivery – Operations Manager	
Power Resources – Market Operations Manager	
Power Resources – Generation Manager	

APPENDIX E

Riverside Load Forecasting Methodology/Models/Assumptions

APPENDIX E
RIVERSIDE LOAD FORECAST METHODOLOGY

Subject: **RPU Wholesale & Retail Load Forecasting Methodologies**

2017 Annual Report – for use in the 2018 IRP Process

Participant: **City of Riverside, Riverside Public Utilities (RPU)**

Date: **November 17, 2017**

Contacts: **Scott M. Lesch, Power Resources Manager – Planning & Analytics**

Qiang Chen, Utility Senior Resource Analyst – Planning & Analytics

1. Overview & Introduction

RPU uses regression based econometric models to forecast both its total expected GWh system load and system MW peak on a monthly basis. Regression based econometric models are also used to forecast expected monthly retail loads (GWh) for our four primary customer classes. These models are calibrated to historical load and/or sales data extending back to January 2003. The following input variables are used in one or more of these econometric models: (a) various monthly weather summary statistics, (b) specific calendar effects, (c) unplanned for (but verified) expansion and contraction of industrial loads, (d) an annual per capita personal income (PCPI) econometric input variable for the Riverside – San Bernardino – Ontario metropolitan service area, (e) the cumulative load loss effects associated with retail customer solar PV installations and all of our measured Energy Efficiency (EE) programs, and (f) the expected net load gain due to increasing Electric Vehicle (EV) penetration levels within the RPU service territory. These models are used to project RPU wholesale gross and peak monthly loads and monthly retail sales twenty years into the future.

Due to a lack of AMI and load research survey data, RPU does not currently produce forecasts of coincident or non-coincident peak loads associated with any specific customer class, or future electrical rates for any customer class and/or tier rate structure. However, our current wholesale and retail forecasting models do explicitly capture and account for the effects of all active RPU EE programs at their current funding and implementation levels, along with the impacts of customer installed solar PV distributed generation and EV penetration within our service territory. This document describes our statistical methodology used to account for these EE, solar PV and EV effects in detail. The interested reader should refer to our SB1037/AB2021 report for more detailed information about RPU's various EE

/ rebate programs, and our SB1 report for more general information about solar PV installation trends within the RPU service territory.

RPU does not currently administer any type of long-term, dispatchable Demand Response program in its service territory. In response to the 2012 SONGS closure, RPU continues to support a Power Partners voluntary load curtailment program to call upon up to 10 MW of commercial and industrial load shedding capability during any CAISO Stage 3 emergency situation. For large TOU customers, we use commercial time-of-use rate structures to encourage and incentivize off-peak energy use. Finally, we have no ESP's in our service territory and we do not anticipate either losing any existing load or gaining any new service territory over the next ten years.

2. Forecasting Approach

2.1. General modeling methodology

The following load based metrics are modeled and forecasted by the RPU Power Resources Division:

- Hourly system loads (MW),
- Total monthly system load (GWh),
- Maximum monthly system peak (MW),
- Total monthly retail loads for our Residential, Commercial, Industrial and Other customer classes (GWh).

All primary monthly forecasting equations are statistically developed and calibrated to 14 years of historical monthly load data. The parameter estimates for each forecasting equation are updated every 6 to 12 months; if necessary, the functional form of each equation can be updated or modified on an annual basis. Please note that this report <u>only</u> summarizes the methodology and statistical results for our monthly forecasting equations. Section 3 of this report describes our monthly system load and system peak equations, while section 4 discusses our class-specific, retail load models.

2.2. Input variables

The various weather, calendar, economic and structural input variables used in our monthly forecasting equations are defined in Table 2.1. Note that all weather variables represent functions of the average daily temperature (ADT, °F) expressed as either daily cooling degrees (CD) or extended heating degrees (XHD), where these indices are in turn defined as

$$CD = \max[ADT-65, 0] \qquad \text{[Eq. 2.1]}$$

$$XHD = \max[55-ADT, 0]\ . \qquad \text{[Eq. 2.2]}$$

Thus, two days with average temperatures of 73.3° and 51.5° would have corresponding CD indices of 8.3 and 0 and XHD indices of 0 and 3.5, respectively.

The "structural" variables shown in Table 2.1 represent calculated cumulative load and peak impacts associated with the following programs and mandates:

- An indicator variable for additional, new industrial load that relocated into the RPU service territory in the 2011-2012 time frame, in response to a two year, city-wide economic incentive program. (Note that this load later migrated out of our service territory in the 2014-2015 time frame; the impact of this load loss is also incorporated into this "EconTOU" structural variable.)
- Avoided energy use directly attributable to RPU energy efficiency programs and rebates.
- Avoided energy use directly attributable to customer installed solar PV systems within the RPU service territory.
- Additional expected load directly attributable to the increasing number of electric vehicles in RPU's service territory.
- An indicator variable for capturing the effects of load migration out of the "Other" retail customer class.

The calculations associated with each of these load and peak impact variables are described in greater detail in subsequent sections. More specifically, section 2.4 describes the amount and timing of the new industrial load that relocated into our service territory in 2011 and 2012, and out of our service territory in 2014 and 2015. Likewise, the retail load migration issue is discussed in section 4.3. Additionally, sections 2.5, 2.6 and 2.7 describe how we calculate the cumulative avoided load and peak energy usage associated with RPU energy efficiency programs and rebates, load loss due to customer installed solar PV systems, and load gain due to vehicle electrification within the RPU service territory, respectively.

Finally, low order Fourier frequencies are also used in the regression equations to help describe structured seasonal load (or peak) variations not already explained by other predictor variables. These Fourier frequencies are formally defined as

$$\mathrm{Fs}(n) = \mathrm{Sine}[\, n \times 2\pi \times [(m\text{-}0.5)/12\} \,], \qquad \text{[Eq. 2.3]}$$

$$\mathrm{Fc}(n) = \mathrm{Cosine}[\, n \times 2\pi \times [(m\text{-}0.5)/12\} \,], \qquad \text{[Eq. 2.4]}$$

where *m* represents the numerical month number (i.e., 1 = Jan, 2 = Feb, .., 12 = Dec). Note also that a second set of Fourier frequencies are also used in our system load and peak models to account for structural changes to our distribution system that occurred in 2014. These 2014 distribution system upgrades were supposed to reduce our energy losses across all load conditions, but in practice appear to have only reduced energy losses under low load conditions.

Table 2.1 Economic, calendar, weather, structural and miscellaneous input variables used in RPU monthly forecasting equations (SL = system load, SP = system peak, RL = retail load(class specific)).

Effect	Variable	Definintion	Forecasting Eqns.		
			SL	SP	RL
Economic	PCPI	Per Capita Personal Income ($1000)	X	X	X
	EMP	Non-farm Employment (100,000)			
Calendar	SumMF	# of Mon-Fri (weekdays) in month	X		
	SumSS	# of Saturdays and Sundays in month	X		
	Xmas	Retail (residential) indicator variable for Christmas effect (DEC = 1, JAN = 1.5, all other months = 0)			X
Weather	SumCD	Sum of monthly CD's	X		X
	SumXHD	Sum of monthly XHD's	X		X
	MaxCD3	Maximum concurrent 3-day CD sum in month		X	
	CDImpact	Interaction between SumCD and MaxCD3	X	X	
	MaxHD	Maximum single XHD value in month		X	
Structural (TOU, EE, PV,EV)	EconTOU	Expansion/contraction of New Industrial load	X	X	X
	Avoided_Load	Cumulative EE+PV-EV load (GWh: calculated)	X		
	Avoided_Peak	Cumulative EE+PV-EV peak (MW: calculated)		X	
	Migration	Load migration out of Other retail customer class (GWh)			X
Fourier terms	Fs1	Fourier frequency (Sine: 12 month phase)	X	X	X
	Fc1	Fourier frequency (Cosine: 12 month phase)	X	X	X
	Fs2	Fourier frequency (Sine: 6 month phase)	X	X	X
	Fc2	Fourier frequency (Cosine: 6 month phase)	X	X	X
	Fs3	Fourier frequency (Sine: 4 month phase)		X	
	Fc3	Fourier frequency (Cosine: 4 month phase)		X	
	Fs2014a	Fourier frequency (on/after 2014 effects)	X	X	
	Fc2014a	Fourier frequency (on/after 2014 effects)	X	X	
	Fs2014b	Fourier frequency (on/after 2014 effects)	X	X	
	Fc2014b	Fourier frequency (on/after 2014 effects)	X	X	
Lag function	Lag(X[i])	Produces value of X for month i-1			X

2.3. Historical and forecasted inputs: economic and weather effects

Annual PCPI data have been obtained from the US Bureau of Economic Analysis (http://www.bea.gov), while forecasts of future PCPI levels reflect the 15-year historical average for the region (i.e., approximately 2.9 % income growth per year). As previously stated, these data correspond to the Riverside-Ontario-San Bernardino metropolitan service area. Note that we now only use the PCPI economic driver in all of our forecasting models because our (previously used) additional set of monthly employment data no longer appears to be statistically significant in any model.

All SumCD, SumXHD, MaxCD3 and MaxHD weather indices for the Riverside service area are calculated from historical average daily temperature levels recorded at the UC Riverside CIMIS weather station (http://wwwcimis.water.ca.gov/cimis). Forecasted average monthly weather indices are based on historical averages; these forecasted monthly indices are shown in Table 2.2. Note that these average monthly values are used as weather inputs for all future time periods on/after September 2017.

Table 2.2. Expected average values (forecast values) for future monthly weather indices; see Table 2.1 for weather index definitions.

Month	SumCD	SumXHD	MaxCD3	MaxHD
JAN	1.6	98.3	1.4	11.6
FEB	2.2	66.8	2.0	9.9
MAR	7.4	41.4	5.4	7.9
APR	26.8	14.4	13.9	4.6
MAY	88.7	2.1	28.2	1.1
JUN	212.1	0.1	45.5	0.1
JUL	340.8	0.0	57.0	0.0
AUG	362.4	0.0	59.8	0.0
SEP	243.7	0.1	50.2	0.0
OCT	93.0	2.7	30.9	1.3
NOV	14.6	27.4	10.4	6.7
DEC	2.7	77.1	2.5	10.4

2.4 Temporary Load/Peak Impacts due to 2011-2012 Economic Incentive Program

In January 2011, in response to the continuing recession within the Inland Empire, the City of Riverside launched an economic incentive program to attract new, large scale industrial business to relocate within the city boundaries. As part of this incentive program, RPU launched a parallel program for qualified relocating industries to receive a two year, discounted time-of-use (TOU) electric rate. In response to this program, approximately 10-12 new industrial businesses relocated to within the city's electric service boundaries over an 18 month period.

In prior iterations of our load forecasting models, staff attempted to directly calculate the approximate GWh energy and MW peak load amounts associated with this economic incentive program. However, since these numbers have proved to be very difficult to accurately determine, in the current forecasting equations staff has instead used indicator variables in the forecasting models that automatically calibrate to the observed load (or peak) gains and losses over the 2011-2014 time period. Table 2.3 shows how the "econTOU" indicator variable is defined, and what the resulting parameter estimate corresponds to in each equation. Note that by definition, this indicator value is set to 0 for all years before 2011 and after 2014.

Table 2.3 Values for econTOU indicator variable used to model RPU's 2011-2014 discounted TOU incentive program. Incentive program was closed in December 2012; nearly all early load gains disappeared by December 2014.

Year	Time Period	EconTOU value		
2011	January - June	0.33	Load parameter value represents incremental Monthly GWh	Peak parameter value represents incremental monthly MW peak
2011	July-December	0.67		
2012	All months	1.00		
2013	All months	1.00		
2014	January - June	0.67		
2014	July - December	0.33		

2.5 Cumulative Energy Efficiency savings since 2005

RPU has been tracking and reporting SB-1037 annual projected EE savings since 2006. These reported values include projected net annual energy savings and net coincident peak savings for both residential and non-residential customers, for a broad number of CEC program sectors. Additionally, these sector specific net energy and peak savings can be classified into "Baseload", "Lighting" and "HVAC" program components, respectively.

In the fall of 2014, we reviewed all of our EE saving projections going back to fiscal year 2005/06, in order to calculate our cumulative load and peak savings attributable to efficiency improvements and rebate programs. The steps we performed in this analysis were as follows:

1. We first computed the sum totals of our projected net annual energy and coincident peak savings for the three program components (Baseload, Lighting, and HVAC) for each fiscal year, for both residential and non-residential customers.
2. Next, we calculated the cumulative running totals for each component from July 2005 through December 2014 by performing a linear interpolation on the cumulative fiscal year components.
3. We then converted these interpolated annual totals into monthly impacts by multiplying these annual values by the monthly load and peak scaling/shaping factors shown in Table 2.4.
4. Finally, we summed these three projected monthly program components together to estimate the cumulative projected monthly load and peak reduction estimates, directly attributable to measured EE activities.

Since 2014, we have continued to update these projections as new information becomes available. It should be noted that these represent interpolated engineering estimates of energy efficiency program impacts. Figure 2.2 shows a graph of the cumulative impact of the projected retail load savings due to EE impacts over time (along with projected load savings attributable to solar PV installations; see section 2.6). Likewise, Figure 2.3 shows a graph of the cumulative impact of the projected retail peak energy savings due to EE impacts over time.

In theory, if such estimates are unbiased and accurate, then when one introduces a regression variable containing these observations into an econometric forecasting model, the corresponding parameter estimate should be approximately equal to -1.05 (to reflect the anticipated load or peak energy reduction over time, after adjusting for 5% distribution system losses). In practice, this parameter estimate may differ from -1.05 in a statistically significant manner, due to inaccuracies in the various EE program sector savings projections.

Table 2.4. Monthly load scaling and peak shaping factors for converting interpolated SB 1037 cumulative annual net load and coincident peak EE program impacts into cumulative monthly impacts.

Month (i)	Load Scaling Factors			Peak Shaping Factors		
	Baseload	Lighting	HVAC	Baseload	Lighting	HVAC
Jan	0.0833 for all months	0.0970	$SumCD_{(i)}/1390$	1.0 for all months	1.164	$SumCD_{(i)}/362.4$
Feb		0.0933			1.119	
Mar		0.0858			1.030	
Apr		0.0784			0.940	
May		0.0746			0.896	
Jun		0.0709			0.851	
Jul		0.0709			0.851	
Aug		0.0746			0.896	
Sep		0.0784			0.940	
Oct		0.0858			1.030	
Nov		0.0933			1.119	
Dec		0.0970			1.164	

2.6 Cumulative Solar PV installations since 2001

RPU has been tracking annual projected load and peak savings due to customer solar PV installations for the last seven years. Additionally, since the enactment of SB1, RPU has been encouraging the installation of customer owned solar PV through its solar rebate program. Figure 2.1 shows the calculated total installed AC capacity of customer owned solar PV in the RPU service territory since 2002.

Based on the installed AC capacity data, we can estimate the projected net annual energy savings and net coincident peak savings for both residential and non-residential customers, respectively. In the summer of 2017, we reviewed all of our solar PV saving projections going back to calendar year 2002, in order to calculate our cumulative load and peak savings attributable to customer installed PV systems within our service territory. These calculations were performed by converting the installed AC capacity data into monthly load and peak energy reduction impacts by multiplying these capacity values by the monthly load and peak scaling/shaping factors shown in Table 2.5. (These scaling and shaping factors are based on a typical south-facing roof-top solar PV installation with a 20% annual capacity factor, and assume that our distribution peaks occur in HE19 from November through February, and HE16 in March through October.) We then summed these projected monthly components together to estimate the cumulative projected monthly load and peak reduction estimates, directly attributable to solar PV distributed generation (DG) activities.

Once again, it should be noted that these represent interpolated engineering estimates of solar PV DG impacts. Figure 2.2 shows a graph of the cumulative impact of the projected retail load savings due to both EE and solar PV-DG impacts over time. Likewise, Figure 2.3 shows a graph of the cumulative impact of the projected retail peak energy savings due to EE and PV-DG impacts over time. As before, if such estimates are unbiased and reasonably accurate, then when one introduces a regression variable containing these observations into an econometric forecasting model, the corresponding parameter estimate should be approximately equal to -1.05 (to reflect the anticipated load or peak energy reduction and distribution system losses over time, etc.). In practice, this parameter estimate may once again differ from -1.05 in a statistically significant manner, due to inaccuracies in the various solar PV-DG savings calculations.

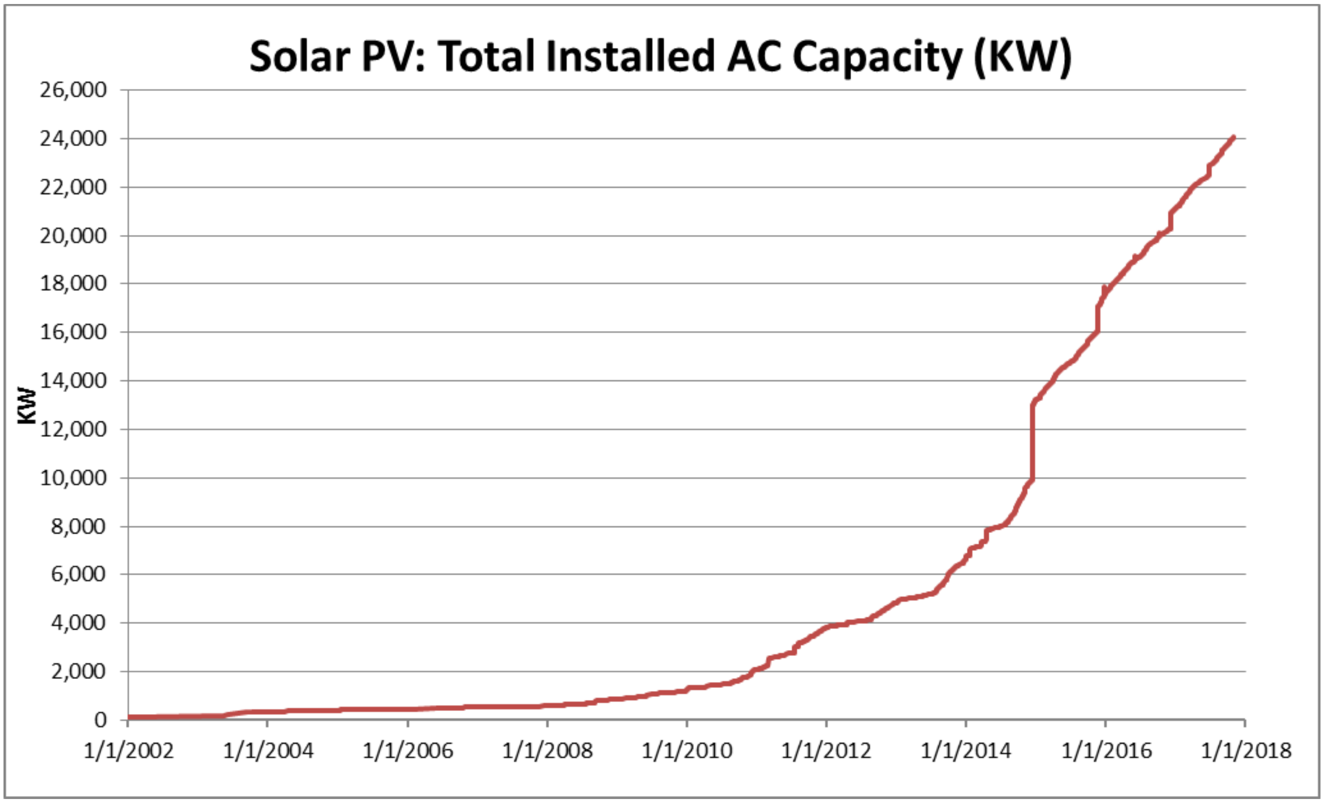


Figure 2.1. Total installed AC capacity of customer owned solar PV in the RPU service territory since 2002.

Table 2.5. Monthly load scaling and peak shaping factors for converting cumulative solar AC capacity into monthly net load and peak PV-DG impacts.

Month	Load Scaling Factors	Peak Shaping Factors
Jan	0.172	0
Feb	0.181	0
Mar	0.195	0.359
Apr	0.211	0.403
May	0.225	0.434
Jun	0.232	0.442
Jul	0.229	0.425
Aug	0.217	0.389
Sep	0.203	0.342
Oct	0.188	0.298
Nov	0.176	0
Dec	0.170	0

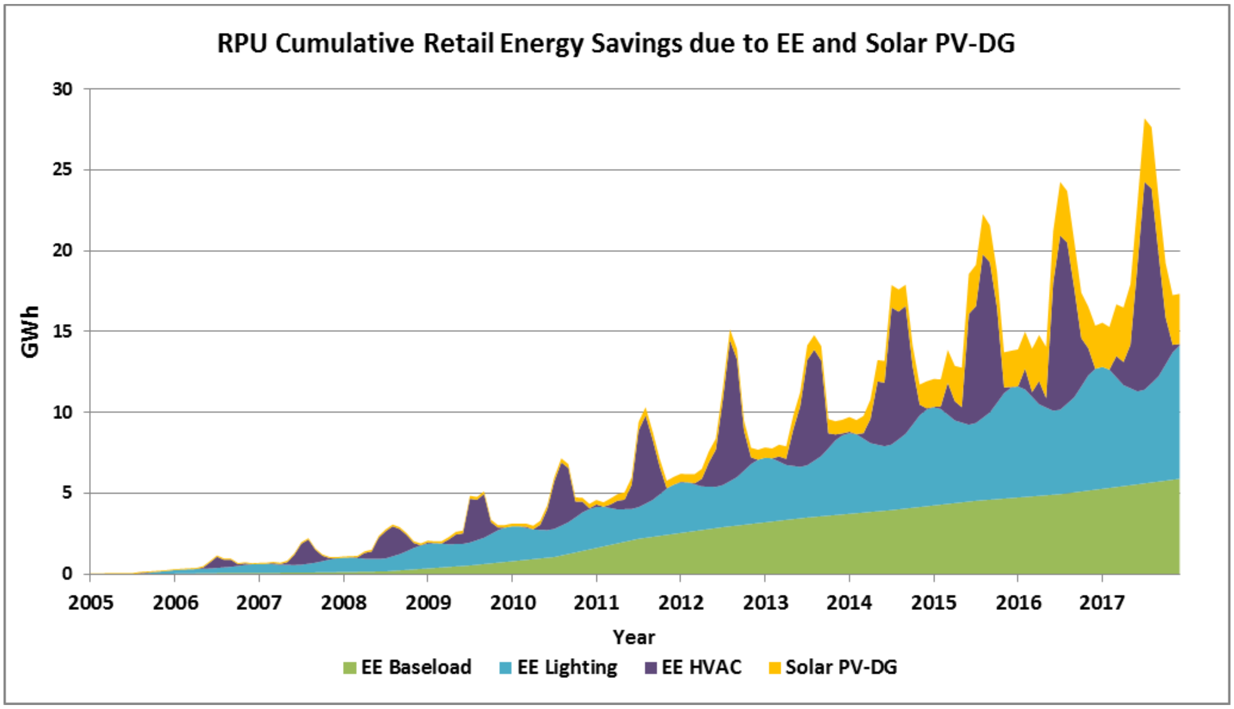


Figure 2.2. Calculated cumulative projected retail energy savings in the RPU service territory due to both EE program and solar PV distributed generation impacts over time.

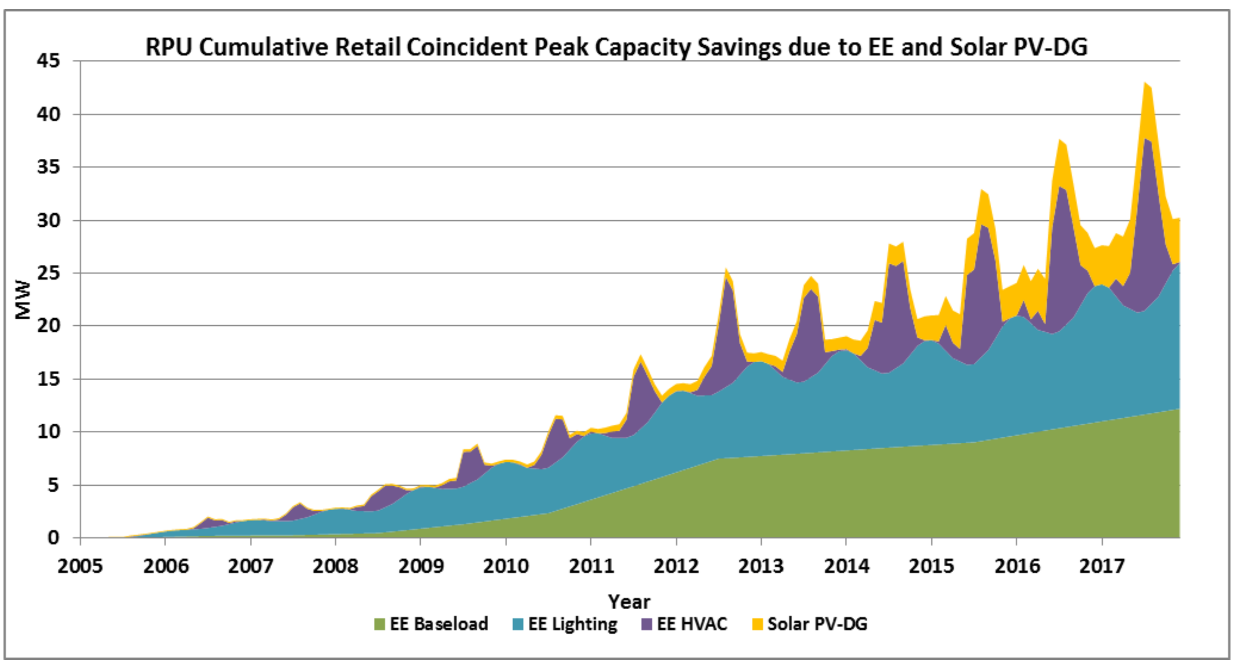


Figure 2.3. Calculated cumulative projected coincident peak capacity savings in the RPU service territory due to both EE program and solar PV distributed generation impacts over time.

2.7 Incremental Electric Vehicle Loads

In early 2017 the CEC released their Transportation Electrification Common Assumptions 3.0 model. This model can be used by CA utilities to forecast EV growth in the utilities service territory through 2030, based on a limited number of objective input assumptions. This model can also be used to forecast a number of emission reduction metrics, in addition to the expected net load growth associated with the forecasted EV penetration level.

Riverside has elected to use this model in our 2017 load forecasting equations and 2018 IRP to estimate our expected net EV load growth. For baseline load forecasting purposes, we have assumed a "business as usual" EV population growth pattern (i.e., 56,100 PEV's in CA in 2017) and used the default 0.56% Riverside estimate for defining our service area PEV population as a percent of the state total. We also assume 5% distribution losses within our service territory and that 10% of our customers EV charging load is self-supplied. Based on these input assumptions, Figure 2.4 shows the projected additional utility electrical load from new PEVs entering our service territory between 2015 through 2030.

Note that for forecasting purposes, these incremental EV loads (above the 2015 baseline level) are treated as net load additions that effectively offset future EE and DG.PV (solar) load losses. Additionally, we assume that 75% of these net load gains will show up in our Residential customer class, with the remaining 25% spread evenly across our Commercial and Industrial classes.

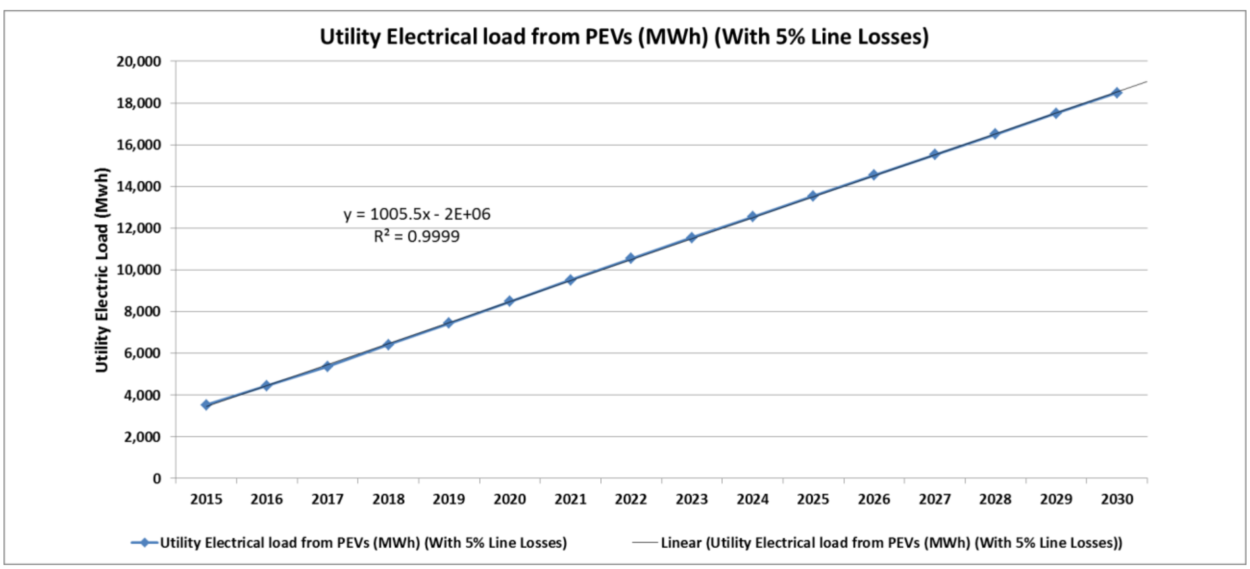


Figure 2.4. Projected 2015-2030 RPU electrical load from EV and PHEV penetration within our service territory.

3. System Load and Peak Forecast Models

3.1 Monthly system total load model

The regression component of our monthly total system load forecasting model is a function of our primary economic driver (PCPI), two calendar effects that quantify the number of weekdays (SumMF) and weekend days (SumSS) in the month, three weather effects that quantify the total monthly cooling and extended heating degrees (SumCD and SumXHD) and the interactive effect of the maximum three-day heatwave impact (MaxCD3), eight low order Fourier frequencies that quantify seasonal impacts both before and after our distribution system upgrades (Fs1, Fc1, Fs2, Fc2, Fs2014a, Fc2014a, Fs2014b, and Fc2014b), one unconstrained Industrial load indicator variable (econTOU), and one initially unconstrained effect that captures the combined impacts of (avoided) EE, PV-DG and (incremental) EV loads. Additionally, the heterogeneous residual variance (mean square prediction error) component is defined to be seasonally dependent; i.e., larger for the summer months (May through October) than the winter months (November through April). Mathematically, the model is defined as

$$y_t = \beta_0 + \beta_1[PCPI_t] + \beta_2[SumMF_t] + \beta_3[SumSS_t] + \beta_4[SumCD_t] + \beta_5[SumXHD_t] + \beta_6[SumCD_t][MaxCD3_t]/100$$

$$+ \beta_7[Fs1_t] + \beta_8[Fc1_t] + \beta_9[Fs2_t] + \beta_{10}[Fc2_t] + \beta_{11}[Fs2014a_t] + \beta_{12}[Fc2014a_t]$$

$$+ \beta_{13}[Fs2014b_t] + \beta_{14}[Fc2014b_t] + \beta_{15}[econTOU_t] + \theta_1[EE_t + PV.DG_t - EV_t] + \varepsilon_{jt} \qquad \text{[Eq. 3.1]}$$

where

$$\varepsilon_{jt\text{ for }j=1(\text{summer}),\,2(\text{winter})} \sim N(0, \sigma_j^2). \qquad \text{[Eq. 3.2]}$$

In Eq. 3.1, y_t represents the RPU monthly total system load (GWh) for the calendar ordered monthly observations and forecasts (*t*=1 → Jan 2003) and the seasonally heterogeneous summer and winter residual errors are assumed to be Normally distributed and temporally uncorrelated. Eqs. 3.1 and 3.2 were initially optimized using restricted maximum likelihood (REML) estimation (SAS MIXED Procedure). These REML results yielded summer and winter variance component estimates of 16.7 and 8.0 GWh^2, suggesting that the variance ratio for the seasonal errors can be assumed to be 2:1. Additionally, the θ_1 parameter estimate was estimated to be -1.303 (0.101), which is reasonably close to the -1.05 avoided/incremental load impact assumption discussed in sections 2.5 through 2.7. Based on these results, Eq. 3.1 was refit using weighted least squares (SAS REG Procedure), where the θ_1 parameter estimate was constrained to be equal to -1.05.

All input observations that reference historical time periods are assumed to be fixed (i.e., measured without error) during the estimation process. For forecasting purposes, we treated all forecasted economic indices and structural effects (PCPI, econTOU, EE, PV.DG and EV) as fixed variables and the forecasted weather indices as random effects. Under such an assumption, the first-order Delta method estimate of the forecasting variance becomes

$$\mathrm{Var}(\hat{y}_t) = \sigma_m^2 + \mathrm{Var}\{\ \beta_4[\mathrm{SumCD}_t] + \beta_5[\mathrm{SumXHD}_t] + \beta_6[\mathrm{SumCD}_t][\mathrm{MaxCD3}_t]/100\ \} \qquad \text{[Eq. 3.3]}$$

where σ_m^2 represents the model calculated mean square prediction variance and the second variance term captures the uncertainty in the average weather forecasts. Note that the second variance term is approximated via the analysis of historical weather data, once the parameters associated with the SumCD and SumXHD weather effects have been estimated.

3.2 System load model statistics and forecasting results

Table 3.1 shows the pertinent model fitting and summary statistics for our total system load forecasting equation, estimated using weighted least squares. The equation explains about 98.8% of the observed variability associated with the monthly 2003-2017 system loads and nearly all input parameter estimates are statistically significant below the 0.01 significance level. Note that the summer and winter variance components were restricted to a 2:1 variance ratio during the weighted least squares analysis; likewise, the avoided_load parameter was constrained to be equal to -1.05.

As shown in Table 3.1, the estimate for the winter seasonal variance component is 8.01 GWh^2; the corresponding summer component is twice this amount (16.02 GWh^2). An analysis of the variance adjusted model residuals suggests that the model errors are also Normally distributed, devoid of outliers and approximately temporally uncorrelated; implying that our modeling assumptions are likewise reasonable. By definition, all of the engineering calculated avoided (and incremental) load effect is accounted for in this econometric model via use of the avoided_load input variable.

The remaining regression parameter estimates shown in the middle of Table 3.1 indicate that monthly system load increases as either/both weather indices increase (SumCD and SumXHD), and the interaction between the SumCD and MaxCD3 is positive and statistically significant. Additionally, weekdays contribute slightly more to the monthly system load, as opposed to Saturdays and Sundays (i.e., the SumMF estimate is > than the SumSS estimate). Finally, our RPU system load is expected to increase as the area wide PCPI index grows over time (i.e., this economic parameter estimate is > 0). However, our load growth will grow more slowly if future EE and/or PV-DG trends increase above their current forecasted levels, or more quickly if future EV penetration levels increase above their baseline levels.

Figure 3.1 shows the observed (blue points) versus calibrated (green line) system loads for the 2003-2017 timeframe. Nearly all of the calibrations fall within the calculated 95% confidence envelope (thin black lines) and the observed versus calibrated load correlation exceeds 0.99. Figure 3.2 shows the forecasted monthly system loads for 2018 through 2030, along with the corresponding 95% forecasting envelope. This forecasting envelope encompasses model uncertainty only, while treating both the weather and projected economic indices as fixed inputs. Note also that these forecasts assume that our future PV-DG installation rates will stabilize at approximately 2 MW of AC capacity per year (once we reach our NEM 1.0 cap), and that our future calculated EE savings rate will continue to be approximately equal to 1% of our total annual system loads. Under these assumptions, our system loads are forecasted to grow at 1.1% per year over the next ten years.

Table 3.1 Model summary statistics for the monthly total system load forecasting equation.

Gross Monthly Demand Model (Jan 2003 - Aug 2017): GWh units
Forecasting Model: includes Weather & Economic Covariates, Fourier Effects
pseudo TOU (unconstrained), 2014 Dist.system Adj and Avoided Load (PV + EE - EV)

Final Forecasting Equation: assumes constrained Avoided Demand Savings

Dependent Variable: GWhload Load (GWh)
Number of Observation Used: 176

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	15	104340	6955.99373	868.06	<.0001
Error	160	1282.12160	8.01326		
Corrected Total	175	105622			

Root MSE	2.83077	R-Square	0.9879
Dependent Mean	176.83540	Adj R-Sq	0.9867
Coeff Var	1.60079		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variance Inflation
Intercept	Intercept	1	-110.31151	9.54998	-11.55	<.0001	0
PCPI	PCPI ($1,000)	1	3.59642	0.09650	37.27	<.0001	1.24443
SumMF		1	5.65973	0.31770	17.81	<.0001	1.60298
SumSS		1	4.84532	0.37928	12.78	<.0001	1.49294
SumCD		1	0.14824	0.01477	10.04	<.0001	55.78514
CDimpact		1	0.06160	0.01993	3.09	0.0024	35.39460
SumXHD		1	0.05040	0.00972	5.18	<.0001	2.63186
Fs1		1	-4.42577	0.75950	-5.83	<.0001	4.60403
Fc1		1	-5.70859	1.01770	-5.61	<.0001	7.99335
Fs2		1	1.09362	0.61457	1.78	0.0771	3.11007
Fc2		1	1.70306	0.48170	3.54	0.0005	1.91111
Fs2014a		1	-4.53164	0.96929	-4.68	<.0001	1.51380
Fc2014a		1	-2.95335	0.94062	-3.14	0.0020	1.43455
Fs2014b		1	4.15689	0.91896	4.52	<.0001	1.38141
Fc2014b		1	-0.04606	0.94319	-0.05	0.9611	1.45711
econTOU		1	6.38842	0.69456	9.20	<.0001	1.05338
avoided_load	EE+PV.DG-EV	1	-1.05000	0	n/a	n/a	0.0

Durbin-Watson D	1.277
Number of Observations	176
1st Order Autocorrelation	0.341

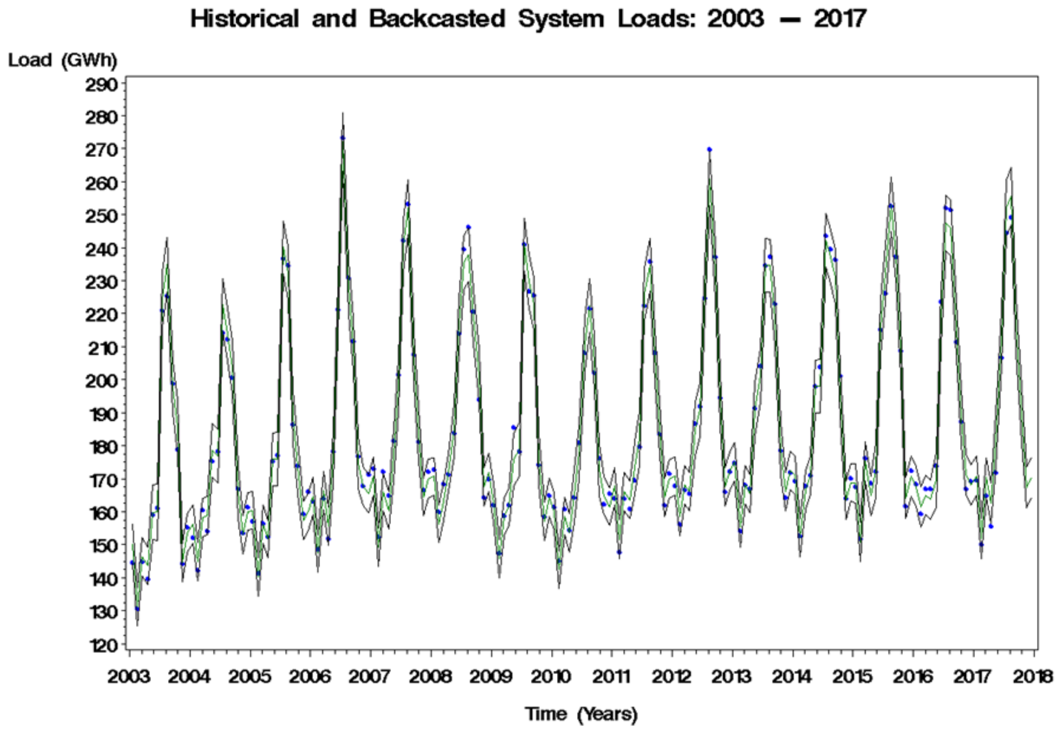


Figure 3.1. Observed and predicted total system load data (2003-2017), after adjusting for known weather conditions.

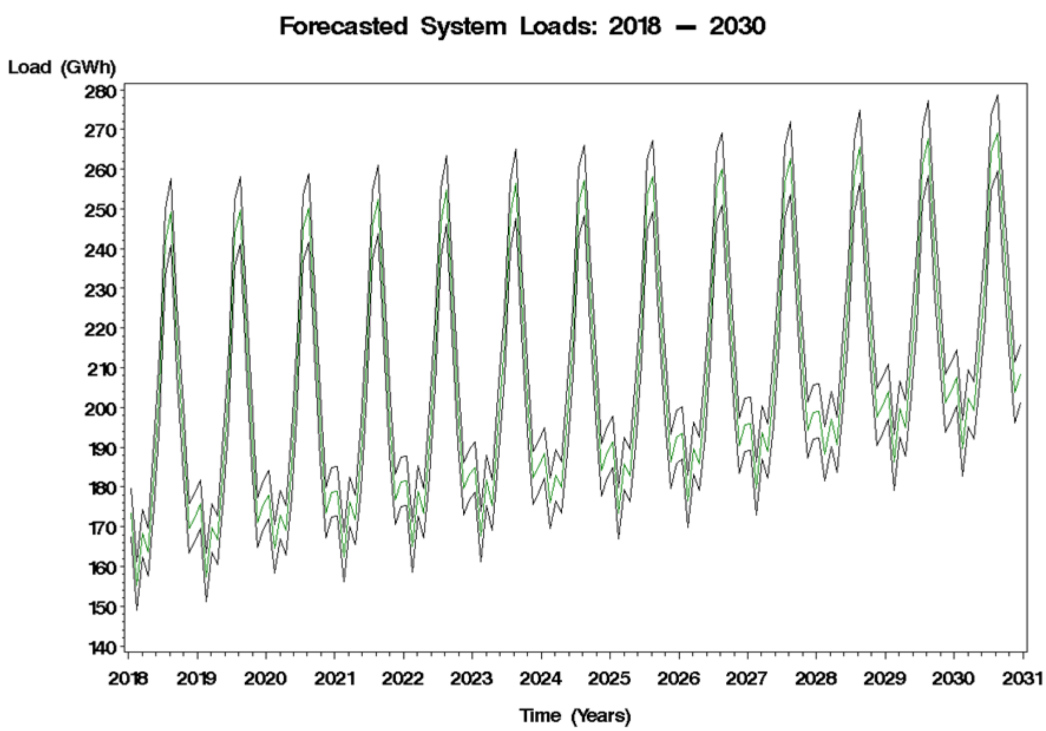


Figure 3.2. Forecasted monthly system loads for 2017-2030; 95% forecasting envelopes encompass model uncertainty only.

Table 3.2 shows the forecasted monthly RPU system loads for 2018, along with their forecasted standard deviations. In contrast to figure 3.2, these standard deviations quantify both model and weather uncertainty. The 2018 forecasts project that our annual system load should be 2291.2 GWh, assuming that the RPU service area experiences typical weather conditions throughout the year.

Table 3.2. 2018 monthly total system load forecasts for RPU; forecast standard deviations include both model and weather uncertainty.

Month	Load (GWh)	Std.Dev (GWh)
JAN	173.5	3.17
FEB	155.1	3.69
MAR	168.4	4.69
APR	163.7	5.36
MAY	183.0	8.86
JUN	205.6	17.41
JUL	241.7	14.21
AUG	249.3	11.36
SEP	217.4	12.77
OCT	192.0	11.41
NOV	169.5	4.58
DEC	172.3	3.15
Annual TOTAL	2291.2	

3.3 Monthly system peak model

The regression component of our monthly system peak forecasting model is a function of our primary economic driver (PCPI), three weather effects that quantify the maximum three-day cooling requirements (i.e., 3-day heat waves), the interaction of this effect with the monthly cooling degrees and the maximum single day heating requirement (MaxCD3, SumCD and MaxHD, respectively), ten lower order Fourier frequencies that quantify seasonal impacts both before and after our distribution system upgrades (Fs1, Fc1, Fs2, Fc2, Fs3, Fc3, Fs2014a, Fc2014a, Fs2014b and Fc2014b), one unconstrained Industrial peak indicator variable (econTOU), and one initially unconstrained effect that captures the combined impacts of (avoided) EE, PV-DG and (incremental) EV peaks. The heterogeneous residual variance (mean square prediction error) component is again defined to be seasonally dependent, but now where the summer period is defined to be one month longer (April through October). Mathematically, the model is defined as

$$y_t = \beta_0 + \beta_1[\text{PCPI}_t] + \beta_2[\text{MaxCD3}_t] + \beta_3[\text{SumCD}_t][\text{MaxCD3}_t]/100 + \beta_4[\text{MaxHD}_t] +$$

$$\beta_5[\text{Fs}(1)_t] + \beta_6[\text{Fc}(1)_t] + \beta_7[\text{Fs}(2)_t] + \beta_8[\text{Fc}(2)_t] + \beta_9[\text{Fs}(3)_t] + \beta_{10}[\text{Fc}(3)_t] +$$

$$+ \beta_{11}[\text{Fs2014a}_t] + \beta_{12}[\text{Fc2014a}_t] + \beta_{13}[\text{Fs2014b}_t] + \beta_{14}[\text{Fc2014b}_t] +$$

$$\beta_{15}[\text{econTOU}_t] + \theta_1[\text{EE}_t\text{+PV.DG}_t\text{-EV}_t] + \varepsilon_{jt} \qquad \text{[Eq. 3.4]}$$

where

$$\varepsilon_{jt \text{ for } j=1(\text{summer}),\ 2(\text{winter})} \sim N(0, \sigma_j^2). \qquad \text{[Eq. 3.5]}$$

In Eq. 3.4, y_t represents the RPU monthly system peaks (MW) for the calendar ordered monthly observations and forecasts (t=1 → Jan 2003) and the seasonally heterogeneous summer and winter residual errors are assumed to be Normally distributed and temporally uncorrelated. Eqs. 3.4 and 3.5 were again initially optimized using REML estimation (SAS MIXED Procedure). These REML results yielded summer and winter variance component estimates of 492.1 and 197.9 MW^2, suggesting that the variance ratio for the seasonal errors is reasonably close to a 2:1 ratio. Additionally, the θ_1 parameter estimate was estimated to be -1.055 (0.322), which almost exactly matches the -1.05 avoided/incremental peak impact assumption discussed in sections 2.5 through 2.7. Based on these results, Eq. 3.4 was refit using weighted least squares (SAS REG Procedure), where the θ_1 parameter estimate was constrained to be equal to -1.05.

As in the total system load equation, all input observations that reference historical time periods were assumed to be fixed. Likewise, we again treated the forecasted economic indices as fixed variables and the forecasted weather indices as random effects. Under such an assumption, the first-order Delta method estimate of the forecasting variance becomes

$$\text{Var}(\hat{y}_t) = \sigma_m^2 + \text{Var}\{\ \beta_2[\text{MaxCD3}_t] + \beta_3[\text{SumCD}_t][\text{MaxCD3}_t]/100 + \beta_4[\text{MaxHD}_t]\ \} \qquad \text{[Eq. 3.6]}$$

where σ_m^2 represents the model calculated mean square prediction variance and the second variance term captures the uncertainty in the average weather forecasts. As before, the second variance term was approximated via the analysis of historical weather data after the parameters associated with the weather effects were estimated.

3.4 System peak model statistics and forecasting results

Table 3.3 shows the pertinent model fitting and summary statistics for our system peak forecasting equation. This equation explains approximately 97.4% of the observed variability associated with the monthly 2003-2017 system peaks. Note that the summer and winter variance components were restricted to a 2:1 variance ratio during the weighted least squares analysis; likewise, the avoided_peak parameter was constrained to be equal to -1.05.

As shown in Table 3.3, the estimate for the winter seasonal variance component is 218.8 MW^2; the corresponding summer component is twice this amount (437.6 MW^2). An analysis of the variance adjusted model residuals suggests that the model errors are again Normally distributed, devoid of outliers and approximately temporally uncorrelated; implying that our modeling assumptions are reasonable. By definition, all of the engineering calculated avoided (and incremental) peak effect is accounted for in this econometric model via use of the avoided_peak input variable.

The remaining regression parameter estimates shown in the middle of Table 3.3 imply that monthly system peaks increases as each of the weather indices increase, but the peaks appear to be primarily determined by the MaxCD3 index. (Recall that this index essentially quantifies the maximum cooling degrees associated with 3-day summer heat waves.) RPU system peaks are also expected to increase as the PCPI index improves over time (i.e., PCPI parameter estimate is > 0). Likewise, our peak loads will grow more slowly if future EE and/or PV-DG trends increase above their current forecasted levels, or more quickly if our EV penetration levels increase. Additionally, not every individual Fourier frequency parameter estimate is statistically significant, although their combined effect significantly improves the forecasting accuracy of the model.

Figure 3.3 shows the observed (blue points) versus calibrated (green line) system peaks for the 2003-2017 timeframe. Nearly all of the calibrations fall within the calculated 95% confidence envelope (thin black lines) and the observed versus calibrated load correlation exceeds 0.98. Figure 3.4 shows the forecasted monthly system peaks for 2018 through 2030, along with the corresponding 95% forecasting envelope. This forecasting envelope again encompasses just the model uncertainty, while treating the weather variables and projected economic and structural indices as fixed inputs. Note that our system peaks are forecasted to grow at just 0.4% per year over the next ten years.

Table 3.3 Model summary statistics for the monthly system peak forecasting equation.

Gross Monthly Peak Model (Jan 2003 - Aug 2017): MW units
Forecasting Model: includes Weather & Economic Covariates, Fourier Effects
pseudo TOU (unconstrained), 2014 Dist.system Adj, and Avoided Peak (PV + EE - EV)

Final Forecasting Equation: using optimized Forier coefs and constrained Avoided Peak Load Effect

Dependent Variable: peak Peak (MW)
Number of Observations Used: 176

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	15	1329764	88651	405.16	<.0001
Error	160	35009	218.80601		
Corrected Total	175	1364773			

Root MSE	14.79209	R-Square	0.9743
Dependent Mean	368.89432	Adj R-Sq	0.9719
Coeff Var	4.00985		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variance Inflation
Intercept	Intercept	1	135.37471	15.57677	8.69	<.0001	0
PCPI	PCPI ($1,000)	1	5.59794	0.50176	11.16	<.0001	1.23228
MxCD3		1	2.83380	0.18781	15.09	<.0001	9.72788
CDimpact		1	0.23740	0.06190	3.84	0.0002	12.50081
MxHD1		1	1.84252	0.34492	5.34	<.0001	2.04283
Fs1		1	-22.84073	3.59551	-6.35	<.0001	3.77879
Fc1		1	-39.10284	4.43850	-8.81	<.0001	5.56814
Fs2		1	2.14027	3.28954	0.65	0.5162	3.26320
Fc2		1	-2.05045	2.47581	-0.83	0.4088	1.84892
Fs3		1	8.22466	2.12678	3.87	0.0002	1.34902
Fc3		1	8.10454	1.90719	4.25	<.0001	1.09717
Fs2014a		1	-4.16401	5.05280	-0.82	0.4111	1.50651
Fc2014a		1	-20.00732	4.93997	-4.05	<.0001	1.44904
Fs2014b		1	11.53635	4.76977	2.42	0.0167	1.36292
Fc2014b		1	4.59643	4.91722	0.93	0.3513	1.45037
econTOU		1	14.78063	3.63449	4.07	<.0001	1.05634
avoided_peak	EE+PV-EV	1	-1.05000	0	n/a	n/a	0.0

Durbin-Watson D	2.138
Number of Observations	176
1st Order Autocorrelation	-0.078

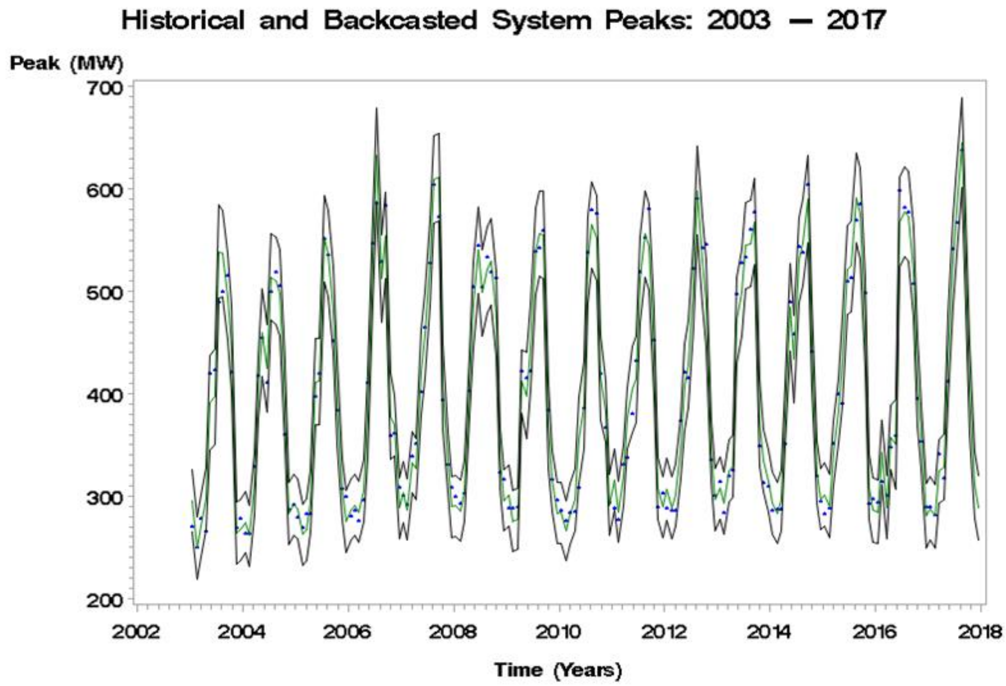


Figure 3.3. Observed and predicted system peak data (2003-2017), after adjusting for known weather conditions.

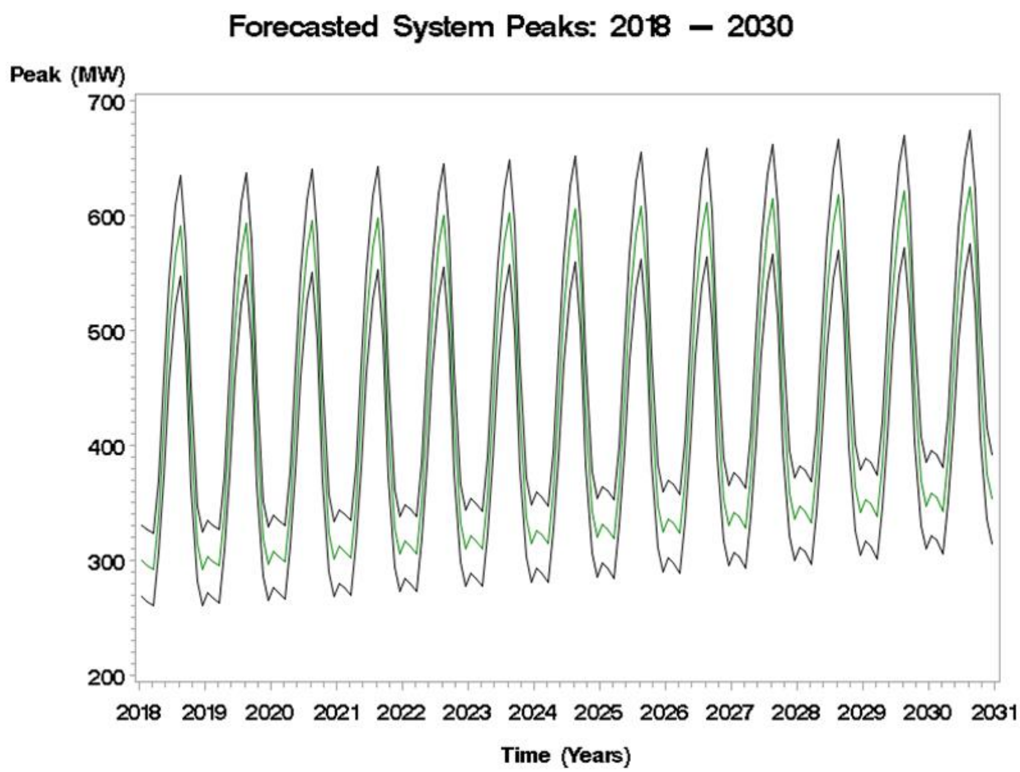


Figure 3.4. Forecasted monthly system peaks for 2018-2030; 95% forecasting envelopes encompass model uncertainty only.

Table 3.4 shows the forecasted monthly RPU system peaks for 2018, along with their forecasted standard deviations. In contrast to figure 3.4, these standard deviations quantify both model and weather uncertainty. The 2018 forecasts project that our maximum monthly system peak should be about 591.5 MW and occur in August, assuming that the RPU service area experiences typical weather conditions throughout the year. Note that this represents a 1-in-2 peak forecast, respectively.

Table 3.4. 2018 monthly system peak forecasts for RPU; forecast standard deviations include both model and weather uncertainty.

Month	Peak (MW)	Std.Dev (MW)
JAN	299.3	19.05
FEB	295.1	23.24
MAR	291.7	26.43
APR	338.3	44.95
MAY	415.1	46.67
JUN	499.3	57.63
JUL	565.8	41.40
AUG	591.5	39.70
SEP	531.2	40.76
OCT	408.2	46.63
NOV	314.9	34.21
DEC	292.5	17.89

3.5 Peak demand weather scenario forecasts

After calculating all of the 2018-2030 monthly peak forecasts and their corresponding standard deviation estimates (that incorporate weather uncertainty), additional peak demand forecasts for more extreme weather scenarios can be produced. Under the assumption that these $\hat{y}_t$ forecasts can be probabilistically approximated using a Normal distribution, the following formulas can be used to calculate 1-in-5, 1-in-10, 1-in-20 and 1-in-40 forecast scenarios:

1-in-5 Peak: $\hat{y}_t + 0.842[\ \mathrm{Std}(\hat{y}_t)\ ]$ [Eq. 3.7]

1-in-10 Peak: $\hat{y}_t + 1.282[\ \mathrm{Std}(\hat{y}_t)\ ]$ [Eq. 3.8]

1-in-20 Peak: $\hat{y}_t + 1.645[\ \mathrm{Std}(\hat{y}_t)\ ]$ [Eq. 3.9]

1-in-40 Peak: $\hat{y}_t + 1.960[\ \mathrm{Std}(\hat{y}_t)\ ]$ [Eq. 3.10]

In Eqs. 3.7 through 3.10, the scale multiplier terms applied to the standard deviation represent the upper 80% (1-in-5), 90% (1-in-10), 95% (1-in-20) and 97.5% (1-in-40) percentiles of the Standard Normal distribution, respectively.

In the RPU service area, our maximum weather scenario peaks are always forecasted to occur in the month of August. Thus, for 2018, our forecasted 1-in-5, 1-in-10, 1-in-20 and 1-in-40 peaks are 624.9, 642.4, 656.8 and 669.3, respectively.

4. Class-specific Retail Load Forecast Models

Our RPU retail load forecasting models are described in this section. However, before discussing each equation in detail, the following modeling issues require clarification. First, it is important to note that our retail sales data span overlapping 30-day billing cycles and are subject to post-billing invoice corrections. As such, our retail load models tend to be inherently less precise and thus subject to significantly more forecasting uncertainty. Additionally, all retail model variance terms are assumed to be constant (i.e., homogeneous) across the calendar year, since seasonal variance effects are difficult to identify and estimate in the presence of these increased signal-to-noise effects.

Second, RPU cannot currently analyze and estimate individual Commercial and Industrial forecasting models, because our Commercial versus Industrial classification schema was changed (over 2005 through 2007) by our Finance/Billing department. Instead, we have estimated a combined Commercial + Industrial load equation, produced combined forecasts using this equation and then split these forecasts into separate Commercial and Industrial predictions using monthly Commercial/Industrial load ratio metrics (historically derived from Jan 2007 through Dec 2013 billing data; see Table 4.3). This issue is discussed in more detail in section 4.3.

Third, and again due to the higher signal-to-noise effects in our billing data, the avoided EE and PV.DG structural terms and incremental EV structural term in our retail models cannot be reliably estimated with reasonable precision. Instead, we have chosen to restrict the parameter estimates for these pooled terms to pre-specified values that are consistent with the corresponding fitted parameters derived from our system load equation, after removing the distribution loss components. These structural constraints are discussed in more detail in sections 4.1 and 4.3, respectively.

Finally, it is important to note that we also constrain the annual sum of our class specific, retail forecasts to be equal to 94.6% of our forecasted annual wholesale loads. (RPU internal distribution losses have averaged 5.4% over the last 15 years.) This constraint is applied by determining a post-hoc, annual adjustment factor (f_R) computed as

$$f_R = [\, 0.946(W) - O \,] \,/\, [\, R + C + I \,] \qquad \text{[Eq. 4.1]}$$

where *R*, *C*, *I* and *O* represent our forecasted annual Residential, Commercial, Industrial and Other retail loads, and *W* represents our forecasted annual wholesale system load. Our final monthly residential, commercial and industrial load forecasts are then adjusted by this annual factor, to ensure that the sum of all our annual retail load forecasts are exactly equal to 94.6% of our annual system load forecasts. Note that this process is done to force our (less accurate) retail load forecasts to align with our loss adjusted system load forecasts, after accounting for the fact that we expect 0% growth in our Other retail load class for the foreseeable future.

4.1 Monthly residential load model (retail sales)

Our monthly residential load forecasting model is a function of one economic driver (prior month PCPI), two current and prior weather effects that quantify the total monthly cooling and extended heating degrees (SumCD and SumXHD), an indicator variable that quantifies an increase in residential load due to late December / early January holiday effects, four low order Fourier frequencies (Fs1, Fc1, Fs2 and Fc2), and an a-priori constrained effect that captures the combined impacts of avoided load due to residential EE and solar PV-DG activities and the incremental load due to additional EV penetration. Mathematically, the model is defined as

$$y_t = \beta_0 + \beta_1[PCPI_{t-1}] + \beta_2[(SumCD_t + SumCD_{t-1})/2] + \beta_3[(SumXHD_t + SumXHD_{t-1})/2] + \beta_4[XMas_t] +$$

$$\beta_5[Fs1_t] + \beta_6[Fc1_t] + \beta_7[Fs2_t] + \beta_8[Fc2_t] - 1.00[EE_{t,R} + PV.DG_{t,R} - Ev_{t,R}] + \varepsilon_t \qquad \text{[Eq. 4.2]}$$

where

$$\varepsilon_t \sim N(0, \sigma^2). \qquad \text{[Eq. 4.3]}$$

In Eq. 4.2, y_t represents the RPU monthly residential load (GWh) for the calendar ordered monthly observations and forecasts (t=1 → Jan 2003) and the homogeneous residual errors are assumed to be Normally distributed and temporally uncorrelated. Eq. 4.2 was optimized using ordinary least squares estimation, after restricting the avoided load parameter estimate to be equal to -1.00 (which corresponds to our system load estimate for this parameter, after removing the impacts of system losses). Additionally, the holiday effect (Xmas) was added to account for an annual residential holiday load increase that is primarily reflected in January billing statements.

All input observations that reference historical time periods were assumed to be fixed (i.e., measured without error) during the estimation process. As with our wholesale models, we treated the forecasted economic index as fixed and the forecasted weather indices as random effects. A first-order Delta method estimate of the forecasting variance was again calculated in the usual manner (where the second variance term is approximated via the analysis of historical weather data, once the parameters associated with the weather effects had been estimated).

4.2 Residential load model statistics and forecasting results

Table 4.1 shows the pertinent model fitting and summary statistics for our residential load forecasting equation. The equation explains 94.5% of the observed variability associated with the monthly 2003-2017 residential loads and all input parameter estimates are statistically significant below the 0.05 significance level. An analysis of the model residuals confirms that these errors were Normally distributed, devoid of outliers and approximately temporally uncorrelated; implying that our modeling assumptions are reasonable.

The regression parameter estimates shown in the middle of Table 4.1 indicate that monthly residential load increases as either/both weather indices increase (SumCD and SumXHD); an increase in one cooling degree raises the forecasted load about twice as quickly as a one heating degree increase. Note that averages of each current and prior month weather indices are used as input variables in the forecasting equation (to account for the delayed billing effect). RPU residential loads are also expected to increase as the area wide PCPI level improves over time. Likewise, our residential load growth would be expected to decrease if future residential specific EE and/or PV-DG trends increase above their current forecasted levels, or increase if a higher level of EV penetration occurs.

Figure 4.1 shows the observed (blue points) versus calibrated (green line) residential loads for the 2003-2017 timeframe. Nearly all of the calibrations fall within the calculated 95% confidence envelope (thin black lines); the observed versus calibrated load correlation is approximately 0.97. Figure 4.2 shows the forecasted monthly system loads for 2018 through 2030, along with the corresponding 95% forecasting envelope. This forecasting envelope encompasses model uncertainty only, while treating the projected economic index and weather variables as fixed inputs. Our residential loads are forecasted to increase at just 0.3% per year for the next 10 years. Or equivalently, our forecasted residential specific EE and/or PV-DG trends are expected to offset nearly all of our future residential load growth over time.

Table 4.2 shows the forecasted monthly RPU residential loads for 2018, along with their forecasted standard deviations. Note that these standard deviations quantify both model and weather uncertainty. The 2018 forecasts project that our annual residential load should be 706.3 GWh, assuming that the RPU service area experiences typical weather conditions throughout the year.

Table 4.1 Model summary statistics for the monthly residential load forecasting equation.

The REG Procedure
Model: MODEL1
Dependent Variable: resi Residential (GWh)

NOTE: Restrictions have been applied to parameter estimates.

Number of Observations Read	456
Number of Observations Used	175
Number of Observations with Missing Values	281

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	8	43942	5492.80692	359.23	<.0001
Error	166	2538.18832	15.29029		
Corrected Total	174	46481			

Root MSE	3.91028	R-Square	0.9454
Dependent Mean	59.14618	Adj R-Sq	0.9428
Coeff Var	6.61121		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variance Inflation
Intercept	Intercept	1	19.43233	3.57086	5.44	<.0001	0
lagPCPI	lag(PCPI)	1	0.77046	0.11521	6.69	<.0001	1.21801
sum2CD	SumCD+lag(SumCD)	1	0.12153	0.00885	13.72	<.0001	15.00539
sum2HD	SumXHD+lag(SumXHD)	1	0.06305	0.01537	4.10	<.0001	3.31075
xmas	XMas Effect	1	8.84804	1.09830	8.06	<.0001	3.03732
Fs1		1	-2.73398	1.18323	-2.31	0.0221	8.00814
Fc1		1	-3.04760	1.16297	-2.62	0.0096	7.73631
Fs2		1	3.17479	0.71471	4.44	<.0001	2.93965
Fc2		1	-2.02375	0.62785	-3.22	0.0015	2.24290
Avoided_load	EE+PV-EV	1	-1.00000	0	n/a	n/a	0.0

Durbin-Watson D	2.176
Number of Observations	175
1st Order Autocorrelation	-0.094

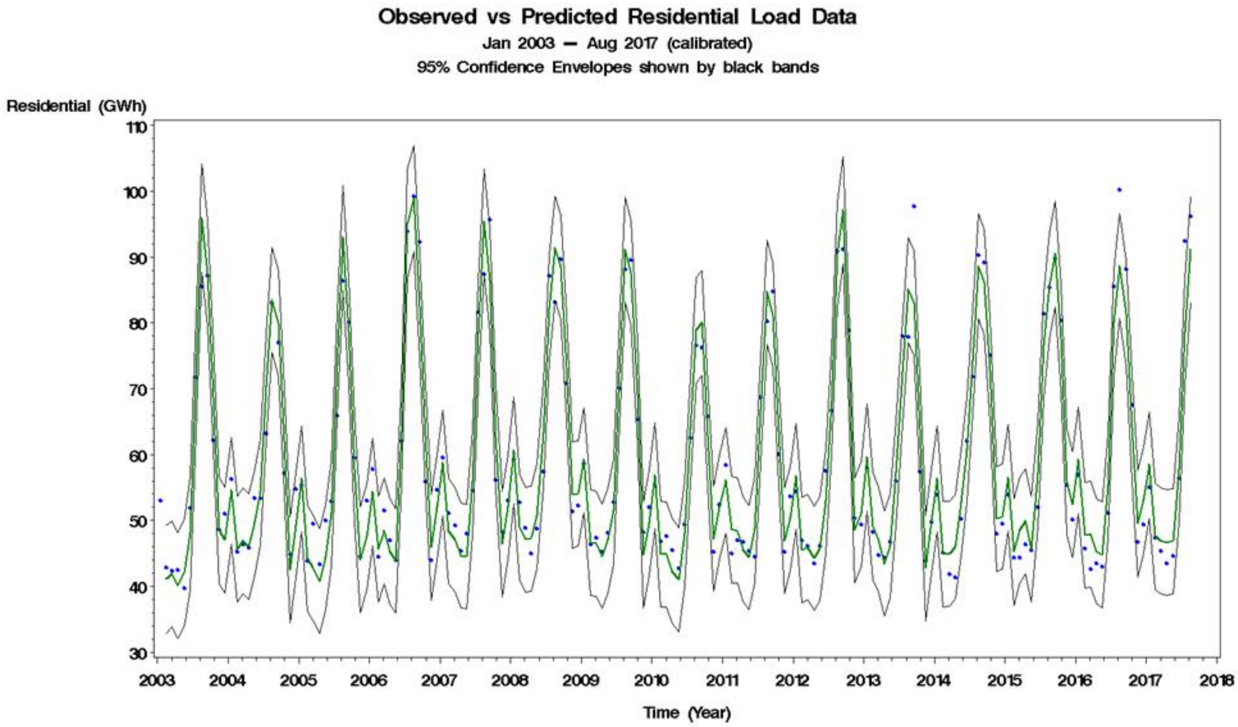


Figure 4.1. Observed and predicted residential load data (2003-2017), after adjusting for known weather conditions.

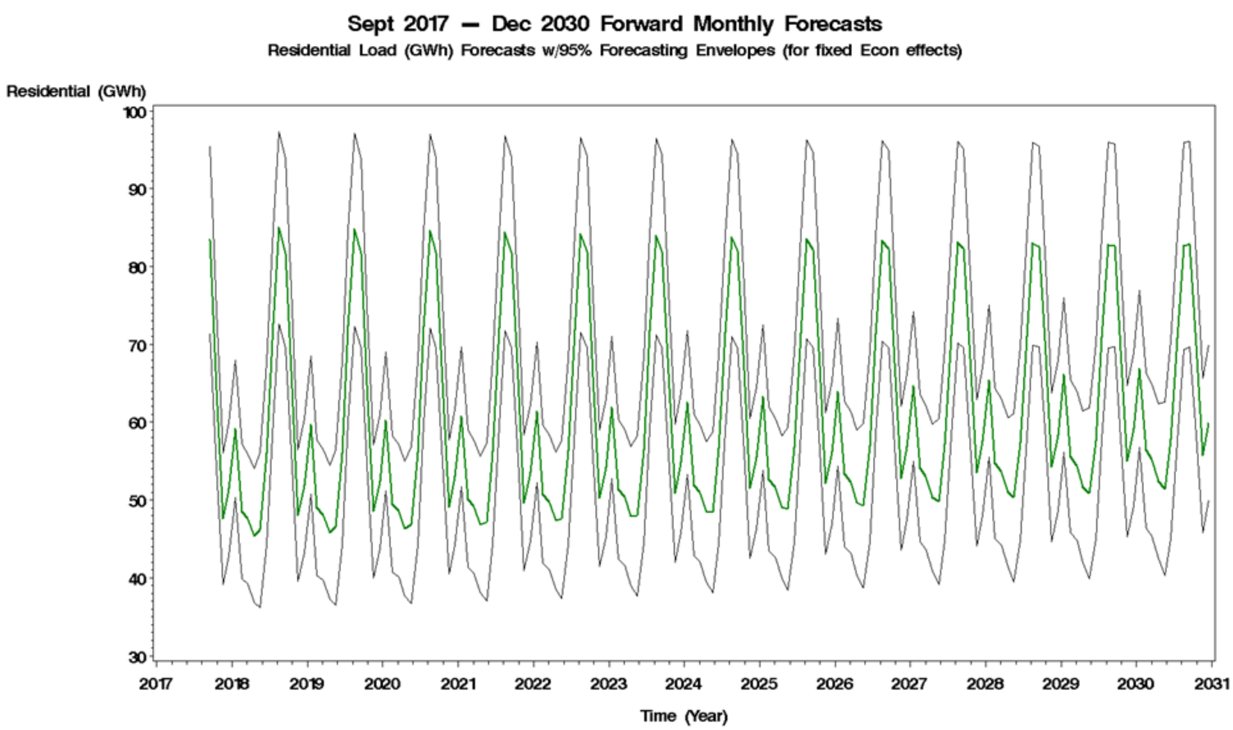


Figure 4.2. Forecasted monthly residential loads for 2018-2030; 95% forecasting envelopes encompass model uncertainty only.

Table 4.2. 2018 monthly residential load forecasts for RPU; forecast standard deviations include both model and weather uncertainty.

Month	Load (GWh)	Std.Dev (GWh)
JAN	59.11	4.85
FEB	48.54	5.34
MAR	47.60	5.06
APR	45.40	5.94
MAY	46.20	7.86
JUN	55.93	11.24
JUL	72.57	15.73
AUG	85.00	10.73
SEP	81.70	12.79
OCT	64.41	13.48
NOV	48.02	8.17
DEC	51.84	4.80
Annual TOTAL	706.31	

4.3 Monthly commercial + industrial load model (retail sales)

Our composite monthly commercial + industrial load forecasting model is a function of one economic driver (prior month PCPI), two current and prior weather effects that quantify the total monthly cooling and extended heating degrees (SumCD and SumXHD), two low order Fourier frequencies (Fs1 and Fc1), one unconstrained Industrial load indicator variable (econTOU), and the combined impacts of avoided load due to commercial/industrial EE and solar PV-DG activities and incremental load due to additional EV penetration. Mathematically, the model is defined as

$$y_t = \beta_0 + \beta_1[PCPI_{t-1}] + \beta_2[(SumCD_t + SumCD_{t-1})/2] + \beta_3[(SumXHD_t + SumXHD_{t-1})/2] +$$

$$\beta_4[Fs1_t] + \beta_5[Fc1_t] + \beta_6[econTOU_t] - 1.00[EE_{t,CI} + PV.DG_{t,CI} - Ev_{t,CI}] + \varepsilon_t \qquad \text{Eq. 4.4}$$

where

$$\varepsilon_t \sim N(0, \sigma^2). \qquad \text{Eq. 4.5}$$

In Eq. 4.4, y_t represents the RPU combined monthly commercial + industrial load (GWh) for the calendar ordered monthly observations and forecasts (*t*=1 → Jan 2003) and the homogeneous residual errors are assumed to be Normally distributed and temporally uncorrelated. Eq. 4.4 was optimized using ordinary least squares estimation (SAS Reg Procedure).

Once again, all input observations that reference historical time periods were assumed to be fixed during the estimation process. Likewise, the forecasted economic index is treated as fixed and the forecasted weather indices are again treated as random effects. As before, a first-order Delta method estimate of the forecasting variance was calculated in the usual manner.

In order to produce individual commercial and industrial load forecasts, it is necessary to split each monthly load prediction into two components. Table 4.3 shows the monthly C/[C+I] ratios.

4.4 Commercial + Industrial load model statistics and forecasting results

Table 4.4 shows the pertinent model fitting and summary statistics for our commercial (C) + industrial (I) load forecasting equation. The equation explains approximately 88% of the observed variability associated with the monthly 2003-2017 C+I loads. Note that although the heating degree effect is non-significant ($t = 1.57$, $p=0.119$), we've elected to retain this weather variable in the equation. (Intuitively, a positive heating degree effect is both reasonable and expected.) Note also that an analysis of the model residuals confirms that these errors are Normally distributed, devoid of outliers and approximately temporally uncorrelated.

The regression parameter estimates shown in the middle of Table 4.4 indicate that monthly residential load increases as either/both weather indices increase (SumCD and SumXHD); once again however, the heating degree effect cannot be judged to be statistically significant. As in the residential model,

Table 4.3. Monthly C/[C+I] ratios.

Month	C/[C+I] ratio
JAN	0.301
FEB	0.300
MAR	0.294
APR	0.287
MAY	0.294
JUN	0.295
JUL	0.307
AUG	0.316
SEP	0.316
OCT	0.300
NOV	0.290
DEC	0.293

averages of each current and prior month weather indices are used as input variables in the forecasting equation (to account for the delayed billing effect). RPU C+I loads are also expected to increase as the area wide PCPI level improves over time. Finally, our C+I load growth will be reduced if future C+I specific EE and/or PV-DG trends increase above their current forecasted levels. Likewise, our C+I load growth will increase if future C+I specific EV trends increase above their current forecasted levels.

Figure 4.3 shows the observed (blue points) versus calibrated (green line) C+I loads for the 2003-2017 timeframe. Nearly all of the calibrations fall within the calculated 95% confidence envelope (thin black lines); the observed versus calibrated load correlation is approximately 0.94. Figure 4.4 shows the forecasted monthly C+I loads for 2018 through 2030, along with the corresponding 95% forecasting envelope. This forecasting envelope encompasses model uncertainty only, while treating the projected economic indices and weather variables as fixed inputs. Note that our C+I loads are forecasted to grow at a 1.8% annual rate, after adjusting for our future C+I EE, solar PV-DG and EV installation trends.

Table 4.5 shows the post-hoc forecasted monthly commercial and industrial loads for 2018, along with their forecasted standard deviations. Note that these standard deviations quantify both model and weather uncertainty. The 2018 forecasts project that our annual commercial and industrial loads should be 457.5 and 1016.5 GWh, respectively, assuming that the RPU service area experiences typical weather conditions throughout the year.

Table 4.4 Model summary statistics for the monthly commercial + industrial load forecasting equation.

The REG Procedure
Model: MODEL1
Dependent Variable: cmind Comm+Indst (GWh)

NOTE: Restrictions have been applied to parameter estimates.

Number of Observations Read	456
Number of Observations Used	175
Number of Observations with Missing Values	281

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	6	29393	4898.79338	209.37	<.0001
Error	168	3930.89355	23.39818		
Corrected Total	174	33324			

Root MSE	4.83717	R-Square	0.8820
Dependent Mean	112.78112	Adj R-Sq	0.8778
Coeff Var	4.28899		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variance Inflation
Intercept	Intercept	1	9.21888	4.34312	2.12	0.0352	0
lagPCPI	lag(PCPI)	1	3.18696	0.14013	22.74	<.0001	1.17742
sum2CD	SumCD+lag(SumCD)	1	0.05495	0.00658	8.35	<.0001	5.40936
sum2HD	SumXHD+lag(SumXHD)	1	0.02359	0.01506	1.57	0.1191	2.07635
s1		1	-5.89334	1.04100	-5.66	<.0001	4.05070
c1		1	-4.39702	0.98993	-4.44	<.0001	3.66297
econTOU		1	5.37892	1.01996	5.27	<.0001	1.03541
avoided_load	EE+PV-EV	1	-1.00000	0	n/a	n/a	0.0

Durbin-Watson D	2.368
Number of Observations	175
1st Order Autocorrelation	-0.191

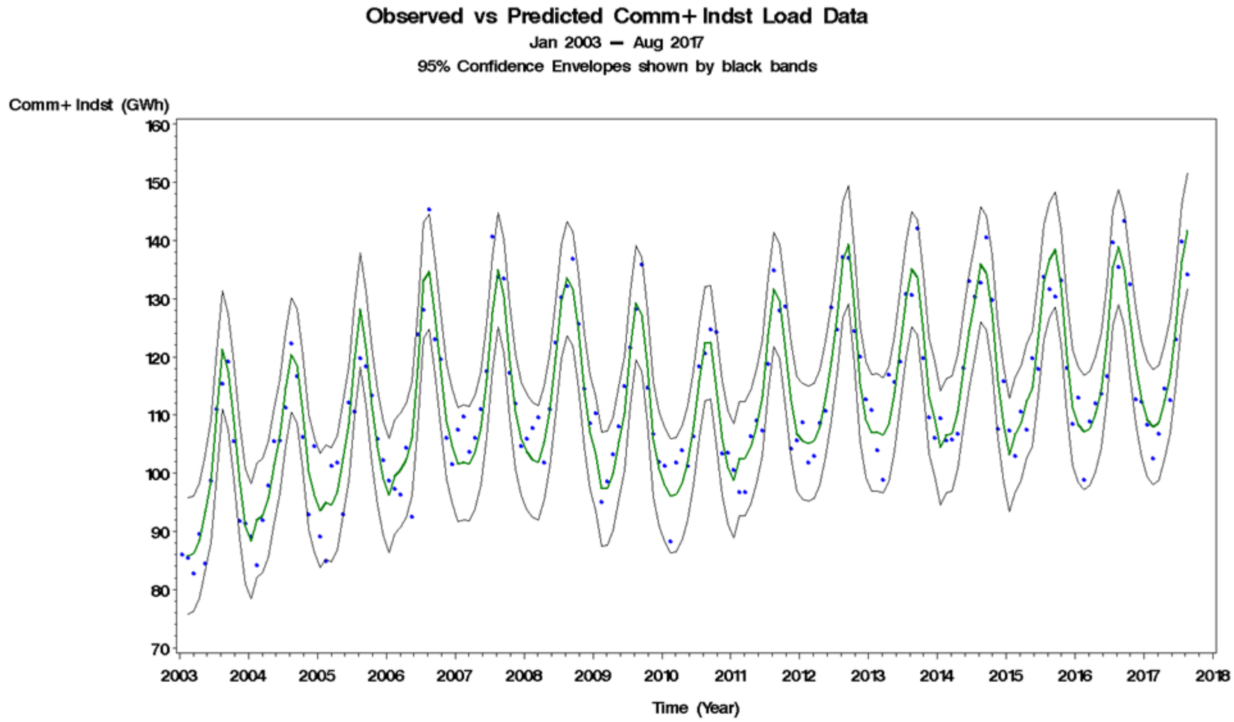


Figure 4.3. Observed and predicted C+I load data (2003-2017), after adjusting for known weather conditions.

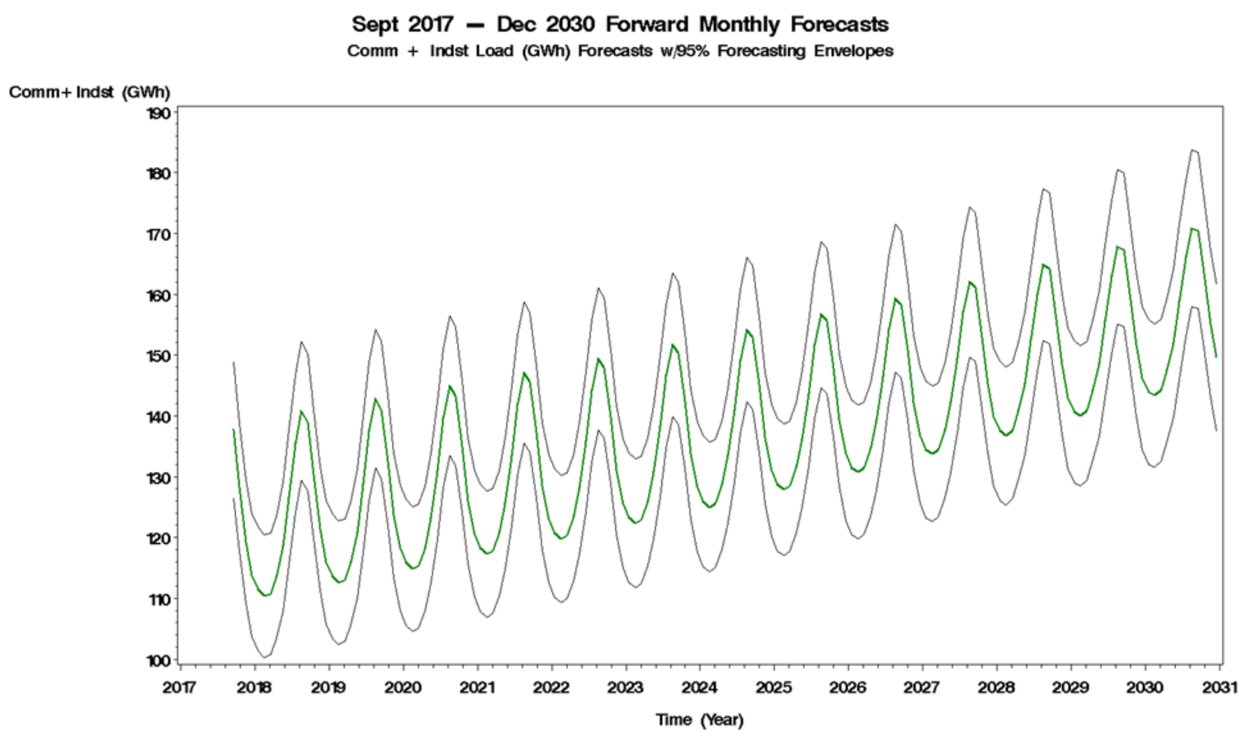


Figure 4.4. Forecasted monthly C+I loads for 2018-2030; 95% forecasting envelopes encompass model uncertainty only.

Table 4.5. 2018 monthly commercial and industrial load forecasts for RPU; forecast standard deviations include both model and weather uncertainty.

Month	Comm Load (GWh)	Std. Dev (GWh)	Indst Load (GWh)	Std. Dev (GWh)
JAN	34.49	1.57	76.98	3.64
FEB	33.63	1.57	76.71	3.66
MAR	33.87	1.52	76.84	3.65
APR	34.04	1.54	79.49	3.82
MAY	35.76	1.80	82.77	4.31
JUN	38.90	2.18	87.65	5.21
JUL	43.43	2.75	92.00	6.20
AUG	45.87	2.28	94.96	4.94
SEP	44.83	2.48	94.05	5.37
OCT	40.75	2.36	89.60	5.51
NOV	36.51	1.74	84.86	4.27
DEC	35.41	1.53	80.58	3.69
Annual Total	457.48		1016.49	

4.5 Modeling and forecasting results for the Other customer class

All remaining RPU customers not classified into one of our three primary customer classes (Residential, Commercial and Industrial) have historically been grouped into an "Other" class. The loads associated with this class currently account for about 1.5% of our total retail load; note that this class is primary comprised of city accounts, street lighting and miscellaneous agricultural customers.

From January 2008 through June 2015, the monthly loads associated with the Other customer class exhibited a fairly stable, seasonal pattern that was independent of changing economic conditions (and is expected to remain so for the foreseeable future). Additionally, this pattern does not exhibit any statistically significant relationship with the observed weather variables, after accounting for three obvious outlier months (January 2009, May 2011, March 2014).

In July 2015, the RPU Finance Division migrated all Agricultural Pumping customers from their miscellaneous contracts over to Industrial TOU accounts (i.e., out of the "Other" class and into the C&I class). Although this load migration barely impacted the C&I class, the apparent load loss in the Other class was significant and must therefore be accounted for in the forecasting model. To account for this migration, a "migration" indicator variable defined as 0 for all time periods before July 2015 and 1 for all periods after July 2015 should be introduced to the model.

Based on the above discussed trends and patterns, our load forecasting model for this customer class is defined to be a function of two low order Fourier frequencies (Fs1 and Fc1), three indicator variables to account for the monthly outliers, and one indicator variable to account for the load migration effect. The corresponding model estimation results (derived using ordinary least squares) are shown in Table 4.6; note that this equation describes about 87% of the observed load variation.

Table 4.7 shows the monthly load forecasts for 2018 along with their forecasted standard deviations. These forecasts do not grow over time, since the forecasting equation for this latter customer class includes no economic driver variables. Additionally, the forecasted standard errors do not reflect any weather uncertainty, since the model is devoid of any weather inputs.

Table 4.6 Model summary statistics for our monthly "other" load forecasting equation.

The REG Procedure
Model: MODEL1
Dependent Variable: other Other (GWh)

Number of Observations Read	396
Number of Observations Used	116
Number of Observations with Missing Values	280

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	6	19.32869	3.22145	119.50	<.0001
Error	109	2.93839	0.02696		
Corrected Total	115	22.26708			

Root MSE	0.16419	R-Square	0.8680
Dependent Mean	2.45829	Adj R-Sq	0.8608
Coeff Var	6.67896		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variance Inflation
Intercept	Intercept	1	2.64568	0.01761	150.27	<.0001	0
s1		1	-0.20683	0.02194	-9.43	<.0001	1.02697
c1		1	0.12608	0.02178	5.79	<.0001	1.02773
migration		1	-0.72269	0.03698	-19.54	<.0001	1.00972
outlier1		1	0.56222	0.16656	3.38	0.0010	1.02021
outlier2		1	-0.65178	0.16653	-3.91	0.0002	1.01983
outlier3		1	-2.19194	0.16652	-13.16	<.0001	1.01969

Durbin-Watson D	1.299
Number of Observations	116
1st Order Autocorrelation	0.332

Table 4.7. 2018 monthly load forecasts for the "Other" customer class.

Month	Load (GWh)	Std.Dev (GWh)
JAN	1.99	0.17
FEB	1.87	0.17
MAR	1.76	0.17
APR	1.69	0.17
MAY	1.69	0.17
JUN	1.75	0.17
JUL	1.85	0.17
AUG	1.98	0.17
SEP	2.09	0.17
OCT	2.16	0.17
NOV	2.16	0.17
DEC	2.10	0.17
Annual TOTAL	23.08	

4.6 Final post-hoc forecasting alignment

As described earlier at the beginning of section 4, a post-hoc correction factor was applied to the Residential, Commercial, and Industrial retail forecasts. This correction factor (calculated via Eq. 4.1.) was used to constrain the annual sums of our retail load forecasts to equal our (loss adjusted) system load forecasts. These annual adjustment factors shifted (i.e., reduced) our retail forecasts from 2% to 5%, respectively.

The monthly 2018-2030 forecasts for all of our retail customer classes are shown in Figure 4.5, along with our total system and total retail load forecasts. Our final annual, class-specific adjusted retail forecasts are reported in Table 4.8, along with our system load and peak forecasts through 2037. Two general features are apparent. First, our forecasted residential loads exhibit a much more pronounced reaction to summer temperature effects. This pattern reflects the increased load associated with running residential air conditioning units during the June-September summer season in the RPU service territory. Second, we do not expect to see significant future load growth in our residential customer class. As discussed previously in section 4.2, our forecasted residential specific EE and/or PV-DG trends are expected to mostly offset any increases in residential load growth over time (i.e., our residential growth rate is ~0.3% per year). In contrast, the forecasted 10-year load growths associated with our commercial and industrial classes are expected to be 1.8% per year. In the Riverside service territory, there is a greater potential for increased commercial and industrial growth. The potential for new residential development is far more restricted, given current Riverside City zoning regulations, City

Council adopted slow-growth initiatives, and the expected avoided load effects attributable to our residential EE programs and solar PV-DG trends. Additionally, the current low EV penetration levels in our service territory are not resulting in enough new load growth to significantly impact this anemic residential trend.

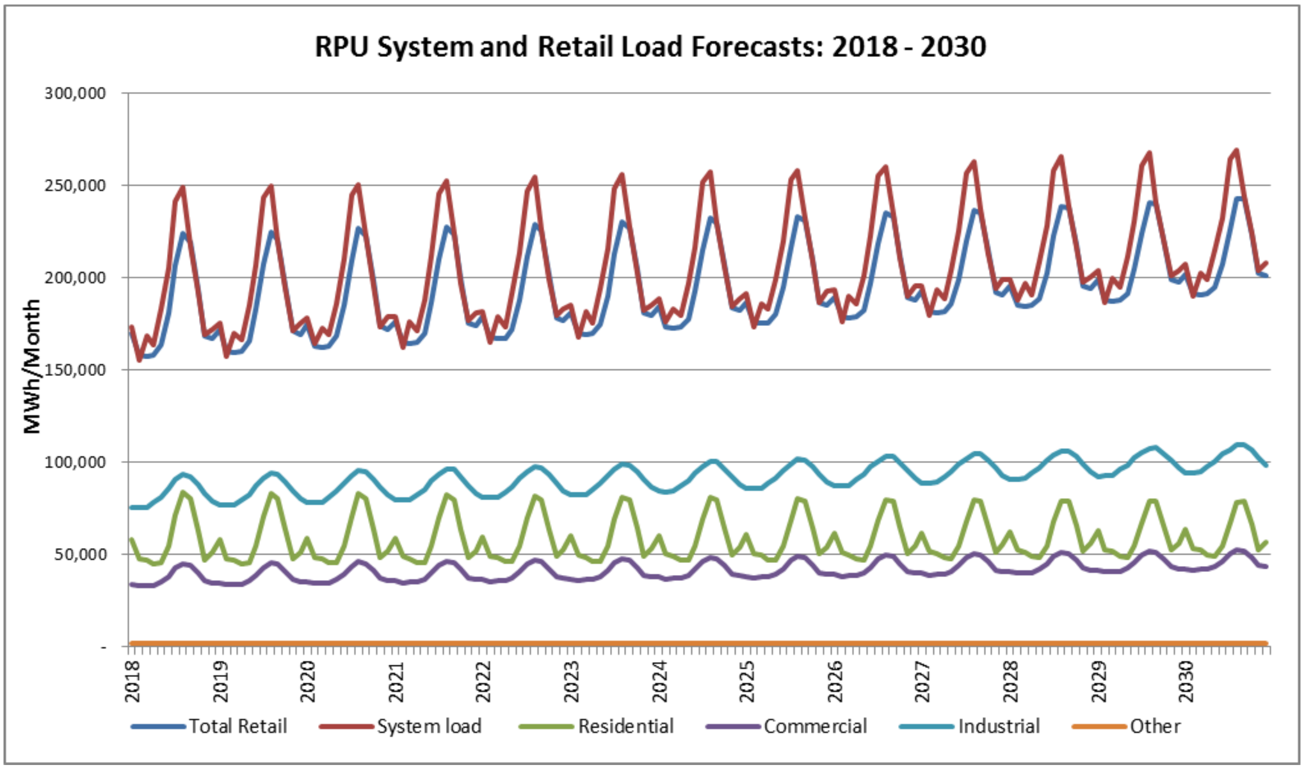


Figure 4.5. RPU monthly retail load forecasts (2018-2030) for the system load, total retail load, and the residential, commercial, industrial and other customer classes.

Table 4.8. Final Retail and System (wholesale) load and peak forecasts: 2018-2037.

Year	System Load	System Peak	Residential	Commercial	Industrial	Other	Total Retail	Ratio R/S
2018	2,291,248	591.5	694,702	449,961	999,782	23,076	2,167,521	94.6%
2019	2,314,846	593.4	695,666	456,566	1,014,536	23,076	2,189,844	94.6%
2020	2,345,843	595.6	698,825	464,661	1,032,605	23,076	2,219,167	94.6%
2021	2,366,858	597.9	698,889	470,785	1,046,297	23,076	2,239,048	94.6%
2022	2,393,687	600.3	700,525	478,128	1,062,699	23,076	2,264,428	94.6%
2023	2,422,473	602.9	702,591	485,911	1,080,082	23,076	2,291,659	94.6%
2024	2,458,739	605.6	706,642	495,273	1,100,976	23,076	2,325,967	94.6%
2025	2,484,437	608.5	707,544	502,509	1,117,148	23,076	2,350,277	94.6%
2026	2,516,886	611.5	710,212	511,179	1,136,507	23,076	2,380,974	94.6%
2027	2,550,641	614.6	713,097	520,164	1,156,569	23,076	2,412,906	94.6%
2028	2,589,567	617.9	717,230	530,279	1,179,145	23,076	2,449,730	94.6%
2029	2,622,242	621.4	719,551	539,121	1,198,894	23,076	2,480,641	94.6%
2030	2,660,182	625.0	723,137	549,114	1,221,205	23,076	2,516,532	94.6%
2031	2,699,613	628.8	726,974	559,467	1,244,317	23,076	2,553,834	94.6%
2032	2,745,998	632.8	732,475	571,344	1,270,819	23,076	2,597,714	94.6%
2033	2,782,334	637.0	735,222	581,125	1,292,665	23,076	2,632,088	94.6%
2034	2,826,544	641.4	739,871	592,626	1,318,338	23,076	2,673,911	94.6%
2035	2,873,269	645.9	745,021	604,709	1,345,306	23,076	2,718,112	94.6%
2036	2,926,316	650.7	751,585	618,209	1,375,425	23,076	2,768,295	94.6%
2037	2,970,424	655.7	755,801	629,812	1,401,333	23,076	2,810,021	94.6%

APPENDIX F

SCE Data Response -SCE-003 Question 6(d) to Cal. Public Advocates, dated 1/27/2019

Southern California Edison
A.15-04-013 – RTRP

DATA REQUEST SET Cal Advocates-A1504013-SCE-003

To: PAO
Prepared by: Lionel Olivares
Job Title: Click here to enter text.
Received Date: 12/21/2018

Response Date: 1/27/2019

Question 06:

II. Capabilities and limitations of Vista Substation to serve both the SCE and RPU 69 kV load
The questions below seek to clarify on the capabilities and limitations of Vista Substation to serve both the SCE and RPU 69 kV load. In October 2012, RPU issued a draft EIR in which RPU described a current SCE operating procedure in the event of the unplanned loss of a SCE 230/69 kV transformer serving the Vista Bus Section C 69 kV.1
6. The described operating procedure places both the RPU and SCE 69 kV load on two Vista 230/69 kV transformers.

a. Please provide the historical peak demands and load duration curves for the SCE portion of the Vista 69 kV load. Please specify whether these are metered loads, recorded loads or weather adjusted loads.
b. Please provide the historical peak demands and load duration curves for the total (SCE + RPU) Vista 69 kV load. Please specify whether these are metered loads, recorded loads or weather adjusted loads.
c. How much of the SCE Vista 69 kV load is SCE able to transfer to other SCE stations in the event of a Vista 230/69 kV outage?
d. What is the historic frequency of SCE 230/69 kV transformer unplanned outages during peak load periods? Has SCE ever had to resort to tripping load served from Vista 69 kV due to the loss of a Vista 230/69 kV transformer? If so, what is the historical frequency of such events.

Response to Question 06:

6. The described operating procedure places both the RPU and SCE 69 kV load on two Vista 230/69 kV transformers.

> **a. Please provide the historical peak demands and load duration curves for the SCE portion of the Vista 69 kV load. Please specify whether these are metered loads, recorded loads or weather adjusted loads.**

Vista A Historic Peak Load Weather Adjusted(MVA)									
2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
282.2	279.7	267.3	252.8	242.8	244.4	287.6	311.5	256.7	249.2

Please see the attached file “Vista A Load Duration Curves 2009-2018.pdf” for the load duration curves for the SCE portion of the Vista 69 kV load. The load duration curves provided are unadjusted metered values for the two Vista 230/69 kV transformers serving the Vista “A” bus section.

b. Please provide the historical peak demands and load duration curves for the total (SCE + RPU) Vista 69 kV load. Please specify whether these are metered loads, recorded loads or weather adjusted loads.

SCE’s historical peak demand values for the years 2009-2018 are provided in the response to 6.a. above. These represent the peak demand values for the selected day of each year and are weather-adjusted values.

RPU’s historical peak demand values for the years 2011-2018 are provided in RPU’s response to Question 1 of this Data Request set. Those values represent RPU’s “peak gross demand and load net of internal generation at the peak gross load hour for those years based upon RPU’s hourly load data.” Those values for any given year are non-coincident to the SCE values and may even have occurred on different dates.

Please see the attached file “Vista A and C Combined Load Duration Curves 2009-2018.pdf” for the load duration curves for the SCE portion of the Vista 69 kV load. The load duration curves provided are unadjusted metered values for all four of the Vista 230/69 kV transformers serving both Vista “A” and “C” 69 kV bus sections.

c. How much of the SCE Vista 69 kV load is SCE able to transfer to other SCE stations in the event of a Vista 230/69 kV outage?

Under normal operating conditions, the amount of 69 kV load SCE is able to transfer to other SCE stations is approximately 10 MVA. However, in the event of the loss of the Vista Substation presumed by the question, SCE assumes that this would be an emergency condition which would effectively allow SCE to transfer a higher amount of load.

Consistent with SCE’s response to question 7.a.ii of this data request set, the amount of load that can transferred out of the Vista 69 kV System to the Mira Loma 69 kV System under emergency conditions is approximately 55 MVA.

d. What is the historic frequency of SCE 230/69 kV transformer unplanned outages during peak load periods? Has SCE ever had to resort to tripping load served from Vista 69 kV due to the loss of a Vista 230/69 kV transformer? If so, what is the historical frequency of such events.

As referenced in other documentation available in this proceeding (A.15-04-013), there were significant unplanned outages affecting Vista Substation on July 3, 2005 and October 26, 2007 resulting in the loss of the ability to serve load. These outages affected RPU’s customers, with the 2007 outage impacting all of RPU’s customers in the City of Riverside.

In addition, subsequent to that outage, other unplanned outages of 230/69 kV transformers have also occurred within SCE service territory during peak load periods. Outage data was pulled from SCE's substation outage database for dates ranging from January 1, 2009 through December 31, 2018. For the purpose of this data request, the peak hours both weekdays and weekends are defined from 4 PM to 9 PM. A total of 4 unplanned SCE 230/69 kV transformer outages were found during peak hours. This equates to an average of approximately 0.4 outages per year during peak load periods, for this time period.

Notably, without restricting this search to peak hours, during this same time period a total of 18 unplanned SCE 230/69 kV transformer outages occurred throughout SCE's service territory. This equates to an average of approximately 1.8 outages per year.

APPENDIX G

NERC Reliability Standard TPL-001-4

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**
2. **Number:** **TPL-001-4**
3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.
4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

   - P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2-1
   - P2-2 (above 300 kV)
   - P2-3 (above 300 kV)
   - P3-1 through P3-5
   - P4-1 through P4-5 (above 300 kV)
   - P5 (above 300 kV)

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3. New planned Facilities and changes to existing Facilities

1.1.4. Real and reactive Load forecasts

1.1.5. Known commitments for Firm Transmission Service and Interchange

1.1.6. Resources (supply or demand side) required for Load

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity’s individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

<table>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">Steady State & Stability
For all extreme events evaluated:
a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
b. Simulate Normal Clearing unless otherwise specified.</td></tr>
<tr><td>Steady State
1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
a. Loss of a tower line with three or more circuits.[11]
b. Loss of all Transmission lines on a common Right-of-Way[11].
c. Loss of a switching station or substation (loss of one voltage level plus transformers).
d. Loss of all generating units at a generating station.
e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
a. Loss of two generating stations resulting from conditions such as:
i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
ii. Loss of the use of a large body of water as the cooling source for generation.
iii. Wildfires.
iv. Severe weather, e.g., hurricanes, tornadoes, etc.
v. A successful cyber attack.
vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
b. Other events based upon operating experience that may result in wide area disturbances.</td>
<td>Stability
1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
e. 3Ø internal breaker fault.
f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances</td></tr>
</table>

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, &

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community

3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in	

		Requirement 1 from Medium to High.	

APPENDIX H

Letters of Support from Critical Customers

KAISER PERMANENTE®
Riverside Medical Center Area

19 Feb 19

To whom it may concern,

Kaiser Permanente is recognized as one of America's leading healthcare providers. Caring for our patients is the number one focus of our organization. Our world-class medical teams are supported by industry-leading technology advances and tools for health promotion, disease prevention, care delivery, and chronic disease management. To keep these advancements moving forward, we depend on basic infrastructure necessities such as electricity.

The Kaiser Riverside Medical Center is one of the largest hospitals and employers in the City of Riverside. We serve some 500,000 members living in the City of Riverside and beyond. Our ability to serve the needs of these members depends heavily on the reliability of critical infrastructure, such electrical power. The Riverside Transmission Reliability Project will help secure this power. As a full- service hospital, the impacts of a long-term black out would be detrimental to our members and, by extension, our region.

As an involved community partner, we understand that the City of Riverside is home to county, state and federal governments, while also hosting more colleges and universities than any neighboring city. We also know that the City of Riverside serves as host to several medical centers, hospitals, and other medical facilities such as clinics. Losing our only connection to the electrical grid due to a natural disaster, accident, or any other unanticipated event would adversely impact these emergency response facilities. Ensuring a reliable source of power for our first responders, such as hospitals and other healthcare facilities in our city is of upmost importance.

The ability to have a redundant electrical system gives the City needed resiliency and the ability to respond to emergencies in an effective and efficient manner.

Kaiser Permanente, Riverside Medical Center is in favor of the Riverside Transmission Reliability Project because we are confident that it will help ensure the electrical needs of our critical medical mission.

George R. Velasco

George R. Velasco
Assistant Hospital Administrator

RIVERSIDE
Community Hospital
Leading with Innovation, Serving with Compassion.

March 1, 2019

Mr. Jensen Uchida
California Public Utilities Commission
717 Market Street, Suite 650
San Francisco, CA 94103

RE: Riverside Transmission Reliability Project (RTRP) Hybrid Proposal - SUPPORT

Dear Mr. Uchida,

Riverside Community Hospital is one of Riverside County's leading healthcare providers. Caring for our patients is the number one focus of our organization. Our medical teams are supported by technology, innovation, and the ability to deliver world class service. To keep our employees and membership continuing toward goals of success, we rely on basic infrastructure needs such as electricity.

Riverside Community Hospital is one of the largest hospitals and employers in the City of Riverside. We not only serve residents in Riverside County, but also residents from outreach areas who require higher levels of care. Our ability to serve the needs of these members depends on the reliability of critical infrastructure, such as electrical power. The Riverside Transmission Reliability Project will help secure this critical power. As a full-service hospital, the impacts of a long-term black out could be detrimental to our patients, physicians and staff.

As an involved community partner with the City, we understand that the City of Riverside is home to county, state and federal governments, while also hosting more colleges and universities than any neighboring city. The City of Riverside also serves as host to several medical centers, hospitals, and other medical facilities such as clinics. Losing our only connection to the electrical grid due to a natural disaster, accident, or any other unanticipated event would adversely impact these emergency response facilities. Ensuring a reliable source of power for our first responders, hospitals, and other healthcare facilities in our city is of upmost importance.

The ability to have a redundant electrical system gives the City resiliency and the ability to respond to emergencies in an effective and efficient manner.

Riverside Community Hospital is in favor of the Riverside Transmission Reliability Project because we are confident that it will help ensure the electrical needs of our critical medical mission.

Respectfully,

Paulina Tam

Paulina Tam
Chief Operating Officer
Riverside Community Hospital

4445 Magnolia Avenue, Riverside, CA 92501 • 951-788-3000 • Fax: 951-788-3201 • www.rchc.org
An Affiliate of Riverside Healthcare System, L.L.C.

UC RIVERSIDE
UNIVERSITY OF CALIFORNIA

OFFICE OF THE CHANCELLOR

May 17,2018

California Public Utilities Commission
717 Market Street, Suite 650
San Francisco, CA 94103

Dear Commissioners,

On behalf of the University of California, Riverside (UCR), I am writing to express our support **for the Riverside Transmission Reliability Project (RTRP) Hybrid Proposal** (referred to as the "Revised Project" in the Draft Subsequent EIR).

900 University Avenue
Riverside, CA 92521
Tel 951.827.5201
Fax 951.827.3866
www.ucr.edu

RTRP is a critical infrastructure need for the university. UCR is not only the largest employer in the city with almost 9,000 employees, but the largest electric user as well.

The current lack of a second connection from the electric grid to the city of Riverside is of significant concern to us. We conduct approximately $150 million annually in extremely sensitive research, and any power interruption potentially puts our research projects in jeopardy.

Riverside is the most populous city in California that lacks a second connection to the grid. In 2006, the California Independent System Operator ordered Southern California Edison to create a second connection for Riverside to ensure the same reliability as other cities. This is a need that has remained unmet for far too long. Further, Riverside's sole connection is inadequate to serve the current demand experienced during peak summer hours.

The Draft Subsequent EIR examined the RTRP Hybrid Proposal and four other alternatives. Among the project possibilities, the RTRP Hybrid Proposal is the most cost-effective and least-intrusive option to serve the needs of Riverside and UCR. RTRP will also provide Riverside with adequate capacity to serve not only existing electrical demand, but long-term system capacity for load growth, and system reliability.

As such, to ensure public safety and protect the economic future of Riverside, UCR requests the California Public Utilities Commission to approve RTRP Hybrid Proposal.

Thank you for your consideration.

Sincerely,

Kim A. Wilcox
Chancellor

APPENDIX I

City Council Memorandum dated Dec. 7, 2004

People Serving People

CITY OF RIVERSIDE

CITY COUNCIL MEMORANDUM

Riverside All-America City 1998

HONORABLE MAYOR AND CITY COUNCIL **DATE:** December 7, 2004

ITEM NO: 41

SUBJECT: **APPROVAL OF PROJECT STUDIES FOR TRANSMISSION RELIABILITY – LAND USE COMMITTEE REFERRAL**

BACKGROUND:

For many years the Board of Public Utilities and staff management have felt concern over the fact that the sole source of energy supply for Riverside Public Utilities (RPU) electric customer-owners has been Southern California Edison's (SCE) Vista Substation, located in Colton, CA. The Board established a specific goal: Build and maintain a safe and reliable infrastructure – reduce dependence on a single point of delivery. Recent catastrophic transformer failures on SCE's and Arizona Public Service's (APS) grids serve to heighten that concern. The installation of the Springs Generation project and the planned Riverside Energy Resource Center (RERC) Project in 2005 will lessen the impact of loss of, but not truly reduce our dependence on SCE's Vista Substation.

Loading Issue – SCE Solution

The present SCE limit at Vista for supplying RPU electric load is 560 MW. RPU load is projected to exceed this limit in 2008. While the RPU generation already mentioned can defer the date when relief is needed, prudent utility practice dictates that small generation peaking plants not be relied upon to defer such a critical capital addition. SCE has proposed adding an additional 280 MW transformer at Vista Substation to solve the loading issue. SCE would require that the RPU 69,000-volt (69 kV) transmission network be split into two subsystems as a part of this project. The cost to add the transformer at Vista and split the 69 kV transmission system is estimated at $70 million initially (2008 dollars). This cost is based on an SCE facilities study and RPU estimates. An additional $154 million of capital costs (2008 dollars) will be required over the next 30 years in order to continue to meet RPU's projected load growth. Some of the 2008 costs and future costs will be in the form of increased SCE annual facilities charges, increasing annual charges from the current $1M to as much as $11M per year.

A significant drawback to this course of action is a space limitation at Vista Substation. The present station layout only has room for one more transformer, the proposed 2008 project. The addition of another transformer further in the future would be extremely difficult and costly, if not impossible. Therefore, as RPU electric load continues to grow, power delivery from a second transmission substation appears inevitable.

Alternative Solution

An alternative to the 2008 Vista transformer addition is for RPU to construct a 230,000-volt (230 kV) transmission substation, similar to SCE's Vista Substation. To better analyze this alternative, RPU requested that SCE perform a Non-Tariff Facilities Study and a Non-Tariff System Impact Study. From those studies, staff determined that this project would include the construction of a double-circuited 230 kV transmission line, a 230-69 kV transmission substation (tentatively named Jurupa), and about 28 miles of 69 kV transmission lines.

Due to the lengthy environmental review required for the 230 kV lines, the project operating date will likely be 2009, possibly requiring use of RPU generation to relieve Vista loading for limited times during the summer of 2008.

To move forward with the alternative, RPU must make an application for a 230 kV transmission service from SCE. The Application will trigger certain requirements for both RPU and SCE. Among them are additional studies which require execution of agreement to pay for them. These requests are on a tight time-line as we officially become a "project" for SCE and RPU will be placed in their "Que".

This item was presented to the Board of Public Utilities at its meeting on November 19, 2004.

FISCAL IMPACT:

More detailed analysis will be required to determine exact costs of the two projects as well as the advancement of the transformer addition. Therefore, SCE will review the previous Non-Tariff System Impact and Facilities Studies and determine if additional studies are required. Typically, these costs are around $60,000 each, $120,000 total. Funds are available in Account 6130000-470616.

ALTERNATIVE:

The alternative is to accept SCE's proposal of adding a new transformer at Vista Substation. RPU customer-owners will continue to be served from a single bulk power delivery point. This alternative is not recommended at this time.

RECOMMENDATIONS:

That the City Council:

1. Approve the application for service from Southern California Edison's 230 kV transmission system;

2. Approve and authorize payment to SCE for studies required by the application for service; and

3. Authorize the City Manager, or his designee, to execute the necessary application documents, and the necessary agreements that are drafted after the application submission, provided that such agreements have been approved as to form by the City Attorney.

4. Refer this item to the Land Use Committee.

Prepared by:

David H. Wright
Interim Public Utilities Director

Approved by:

Thomas P. Evans
Interim City Manager

Approved as to form:

for Gregory P. Priamos
City Attorney

Certifies fund availability:

Paul C. Sundeen
Finance Director

TPE/SB/LH:gsg
g:user\gg\City Council\Council Memos\2004\12-07-04 Transmission Reliability-Hill.doc

Attachment: Board of Public Utilities Minutes – November 19, 2004
Application

DISCUSSION CALENDAR

(4) APPROVAL OF PROJECT STUDIES FOR TRANSMISSION RELIABILITY

Assistant Director Steve Badgett began the discussion regarding the Board's Goal to Reduce Dependence of Single Points of Delivery for Water and Electric services. Riverside Public Utilities' (RPU) dependence on Southern California Edison's (SCE) Vista Substation, and future expansion of that facility to serve RPU's electric load, is a key part of that solution. Mr. Badgett discussed a number of options and studies both SCE and RPU's staff has performed in the past two years. One solution is to construct another 230 kV substation. For RPU to do that, they must have a 230 kV transmission service. An Application for Transmission Service must be made to SCE. When that Application is made, it triggers certain requirements from both SCE and the Applicant. Most of these requirements are short term, meaning a need of turn around for Study Agreements, payment for those agreements, and other items.

There was discussion on the locations of the Substation and routing of the 230 kV lines. Assistant Director Badgett reinforced that this Application is the first step and if RPU moves forward with this option, there will be an Environmental review and process to address the specifics of the proposed project. This Application and related studies will give RPU staff and management a clearer picture of what is the best alternative for its long-term reliability.

The Board of Public Utilities:

1. Approved and recommended to the City Council the application for service from Southern California Edison's 230 kV transmission system;
2. Approved and recommended to the City Council to authorize payment to SCE for studies required by the application for service; and
3. Authorized the City Manager, or his designee, to execute the contract and necessary documents.

Motion – Anderson. Second – Stockton.

Ayes: Hubbard, Anderson, Barnhart, Stockton, Newberry, Jr., P.E., and Tavaglione.

Noes: None

Abstain: None

Absent: Lalit Acharya (absence due to personal business)
Chuck Beaty (Alternate 1) (absence due to business)

DRAFT – November 22, 2004

REF: PUR-04-xxx

Mr. Gilbert H.L. Tam
Southern California Edison Company
Manager, Grid Contracts
P.O. Box 800
Rosemead, California 91770

Subject: City of Riverside Application For Transmission Interconnection

Dear Mr. Tam:

As you know, the City of Riverside has been investigating alternatives for facilities that will be necessary to maintain reliable transmission service to Riverside's load in light of anticipated load growth. As part of that investigation, Riverside has funded certain "non-tariff" studies performed by Edison to determine the service alternatives that are most likely to provide reliable long-term firm transmission and distribution service to Riverside's citizen-ratepayers. As a result of those studies and the provisions contained in the ISO Tariff, Transmission Control Agreement, and Edison's Transmission Owner Tariff ("TO Tariff"), Riverside hereby provides this application to Edison for a new transmission-level interconnection to serve a portion of Riverside's existing retail load on a firm basis.

Riverside continues to have concerns regarding the sufficiency of equipment at Vista necessary for Edison to provide WDAT service to Riverside comparable to the distribution service Edison provides its own customers. Specifically, Riverside is concerned that sufficient transformer capacity may not exist at Vista to accommodate Riverside's planned load growth or a transformer failure prior to the planned in-service date of Riverside's transmission-level interconnection. Riverside is aware that Edison will use alternative means to serve Edison's own Vista load in the event of transformer failure or overload, including the utilization of "back-up" capacity available from the two transformers directly assigned to Riverside for Edison cost recovery purposes. Riverside strongly encourages Edison to install additional transformer capacity at Vista in order to serve Edison's own customers and to provide reciprocal "back-up" capacity to Riverside in the event that one of the two existing transformers serving Riverside load should become overloaded or unavailable.

As provided in Section 10.3 of the TO Tariff and 18 CFR § 2.20, Riverside supplies the following information:

1. The party requesting wholesale load interconnection is the City of Riverside, by and through its Public Utilities Department. For purposes of this application, Riverside's designated contact is Mr. Stephen H. Badgett, Assistant Director/Energy Delivery. Mr. Badgett may be contacted as follows:

Mr. Stephen H. Badgett
City of Riverside Public Utilities Department
Assistant Director/Energy Delivery
3900 Main Street
Riverside, California 92522

Telephone: (951) 826-5504
Facsimile: (951) 369-0548
Email: sbadgett@riversideca.gov

2. The interconnection point to the ISO Controlled Grid contemplated by Riverside is illustrated in the attached Diagram A.

This possible interconnection would be performed by looping Edison's existing Mira Loma-Vista No. 1 230 kV line through a new City of Riverside substation to be constructed, owned, operated and maintained by Riverside. By sectionalizing Riverside's retail load, approximately half of that load would be served by the new substation and the remainder would continue to be served under the existing WDAT service provided by Edison.

3. The new interconnection's capacity is initially anticipated not to exceed 560 MVa based on the sum of the nameplate ratings of the two 230/69 kV transformers expected to be installed at Riverside's new substation.

4. Riverside proposes energizing the new interconnection as soon as practicable after construction and testing are completed, but at least by early 2008. Once placed in service, Riverside does not foresee discontinuing the proposed interconnection.

5. Riverside is not a New Facility Operator; therefore, generator data sheets are not required to be submitted by Riverside in connection with this application. Nevertheless, Riverside will provide such information related to Riverside's existing Springs generation project and its proposed Riverside Energy Resource Center generation project as may reasonably be required for Edison to perform the system impact and facilities studies contemplated by Edison's TO Tariff for the interconnection of wholesale load.

6. Riverside possesses a geographically diverse and ever-changing portfolio of resources, primarily located outside of the ISO Controlled Grid. As such, Riverside cannot, with reasonable certainty, provide the electrical location of each possible resource whose energy is likely to be deemed to utilize the new interconnection and firm transmission service obtained by Riverside from the ISO.

7. Although Riverside is not a New Facility Operator, the location of the ultimate load to be served by the new interconnection is within the service territory of the City of Riverside Public Utilities Department.

8. The City of Riverside is an entity eligible to request transmission under sections 211(a) and 213(a) of the Federal Power Act ("FPA") and this request is intended to satisfy the

"request for transmission services" described therein and the requirements for an application under § 10.3 of the TO Tariff.

9. This interconnection application is not a request for mandatory retail wheeling prohibited under section 212(h) of the FPA.

10. Other parties likely to provide transmission service to deliver electric energy to, and receive electric energy from, Edison's grid in connection with the new interconnection will be those parties having the right to provide such service to and from the ISO Controlled Grid.

11. The Edison facilities necessary for the requested interconnection will be New High Voltage Facility additions for which the costs are recoverable under the ISO Grid-wide component of the High Voltage Access Charge pursuant to Appendix F, Schedule 3, § 1.1 of the ISO Tariff.

12. Upon request by Edison, Riverside will promptly provide load factor and such other retail load information as may reasonably be required for Edison to evaluate Riverside's interconnection request.

Riverside intends to aggressively pursue the timely construction and placing in service of this additional point of interconnection. It is Riverside's understanding that Edison will determine, within ten business days of Edison's receipt of this application, whether this application for transmission interconnection is sufficiently complete and constitutes a Completed Interconnection Application, as that term is defined in the TO Tariff. Also, Riverside is interested in understanding more fully Edison's reference to its "queue" in connection with the studies performed by Edison related to the transmission-level interconnection of a portion of Riverside's retail load.

Riverside hereby requests that the parties meet as soon as practicable to exchange additional information related to Riverside's interconnection request and confirm the parties' respective obligations leading to completion of the interconnection. As such, please contact Mr. Stephen Badgett as provided above with any questions Edison may have regarding this application and to schedule the requested meeting.

Sincerely,

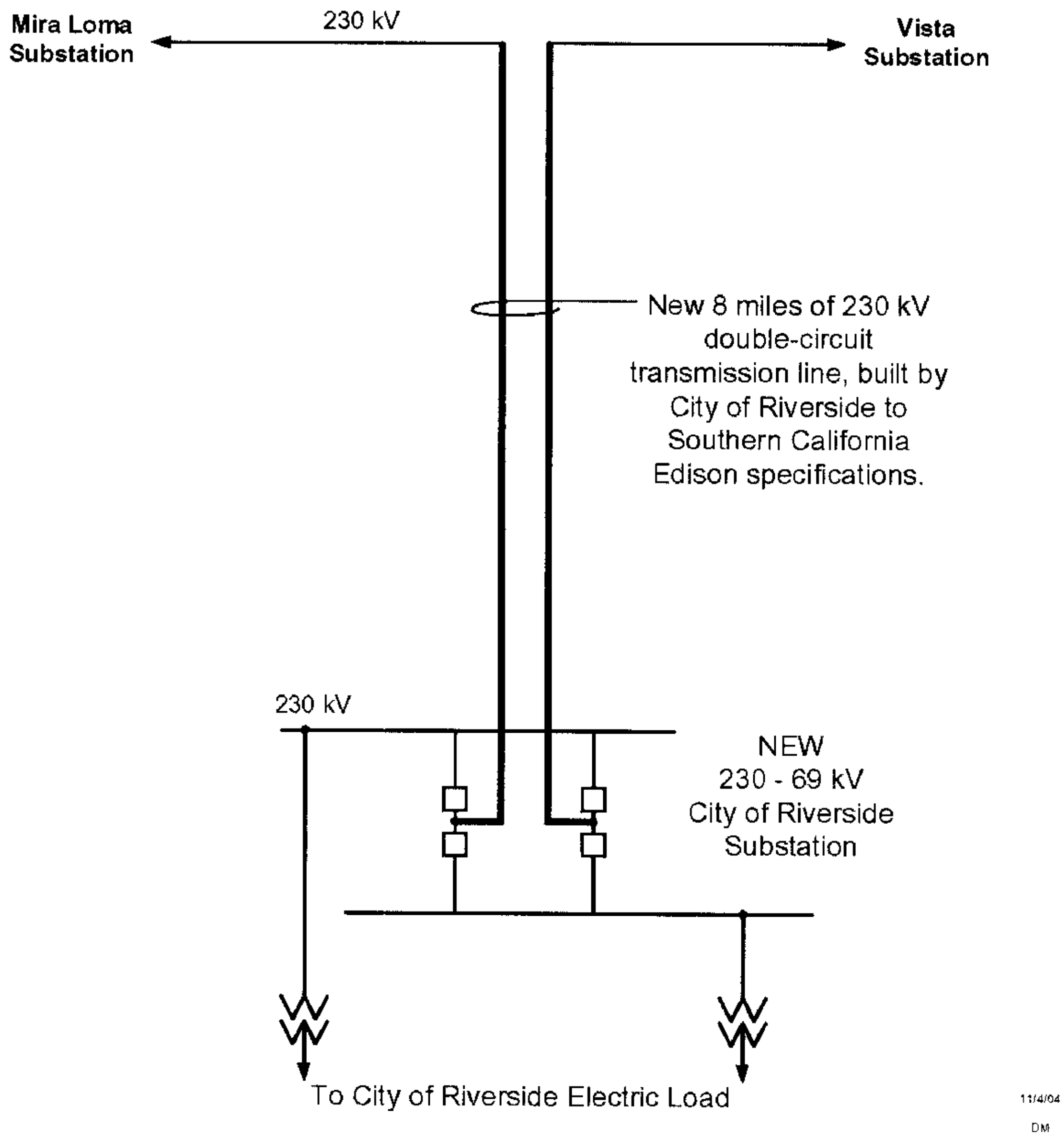
David H. Wright
Interim Public Utilities Director

c: Steve Badgett
Donna Stevener
Eileen Teichert
Ms. Bonnie Blair (Thompson Coburn)
Mr. Armando Perez (CAISO)

Mr. Keoni Almeida (CAISO)

Diagram A

Possible 230 kV Transmission Interconnection Between City of Riverside and Southern California Edison



APPENDIX J

Witness Qualifications

- Mark Annas, City of Riverside Fire Department Office of Emergency Management
- Daniel Garcia, Assistant General Manager, Resources
- George Hanson, Assistant General Manager, Energy Delivery
- Scott Lesch, Ph.D., Power Resources Manager, Resource Planning & Technology Integration Unit
- Chief Jennifer McDowell, Division Chief / Fire Marshal
- Bob Tang, Ph.D.

Q. Please state your name.

A. Mark Annas.

Q. What are your qualifications?

A. Please see the included CV following this page.

Q. What section and the material contained therein are you sponsoring?

A. I am co-sponsoring Section II.C.1(f) with Chief Jennifer McDowell.

Q. Was this material prepared by you or under your supervision?

A. Yes.

Q. Insofar as this material is factual in nature, do you believe it to be correct to the best of your knowledge?

A. Yes.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best professional judgment?

A. Yes.

Mark D. Annas

3085 St Lawrence St • Riverside, CA 92504 • (951) 320-8103 • mannas@riversideca.gov

Professional Experience

City of Riverside Fire Department Office of Emergency Management, Riverside, California
February 2014 to present
Emergency Services Administrator/UASI Administrator, August 2016 to Present

- Administer nearly $9 million in funded projects across three fiscal years for the Riverside Urban Area Security Initiative (UASI) homeland security grant program.
- Provide expertise to and support to senior leaders (including c-suite) for 2 counties and 3 major cities.
- Prepare reports and presentations for elected and appointed leadership.
- Manage and coordinate over $500,000 general fund budget with supervision of five (5) staff at Office of Emergency Management.
- Lead the Regional Critical Infrastructure Protection (CIP) program for two counties coordinating with public and private site operators. Manage CIP site assessment project contract ($229,000) and CIP asset database.
- Manage the National Critical Infrastructure and Special Events Data Calls for two counties
- Lead and coordinate the development of the Threat and Hazard Identification Risk Assessment (THIRA) and Local Hazard Mitigation Plan (LHMP).
- Draft and maintain the Emergency Operations Plan and Emergency Support Function Annexes.
- Coordinate Regional Homeland Security Strategy planning.
- Manager of the Emergency Operations Center (EOC) during activations.
- Develop, equip, and coordinate the activities of the EOC to ensure state of readiness.
- Conduct exercises, briefings and tours of the EOC for stakeholders.
- Respond as member of on-call/duty officer team to major emergency incidents.
- Analyze Damage Assessments following emergency incidents.
- Serve as Public Information Officer for media inquiries and social media.
- Deliver training to staff on emergency operations roles and responsibilities.
- Represent the office with local, state, federal government and non-governmental partners.
- Deployed during Hurricane Harvey to lead the Harris County Regional Joint Information Center.

Emergency Operations Coordinator/UASI Special Projects Coordinator, February 2014 to August 2016

- Served as deputy administrator for the Office of Emergency Management.
- Served as Deputy EOC or EOC Manager during activations of the EOC.
- Led and coordinated various emergency and continuity planning efforts.
- Responded as member of on-call/duty officer team to major emergency incidents.
- Managed the financial disaster cost recovery process for the city, which included coordinating with all city departments, Riverside County, California Office of Emergency Services and federal agencies.
- Managed general fund budget of $50,000 and grant purchases of over $30,000.
- Prepared reports and presentations to City Council, Executive Leadership Team and city management.
- Led the CIP program for the Riverside UASI coordinating with public sector and private site operators. Managed CIP site assessment project contract ($217,000) and CIP asset database administrator.

- Delivered training to staff on emergency operations roles and responsibilities. Increased emergency messaging as member of the Federal Communications Commission - Communications Security, Reliability and Interoperability Council.

Riverside County Fire Department, Perris, California
Public Information Specialist, March 2013 to February 2014

- Provided timely and accurate information to internal and external audiences.
- Managed department social media pages and social media campaigns.
- Assisted in the running of the Fire Information Call Center.
- Managed the Public Affairs Bureau SharePoint page.
- Coordinated public education efforts with 90+ stations and bureaus.

City of Riverside Fire Department Office of Emergency Management, Riverside, California
Emergency Services Coordinator – UASI Emergency Planner, January 2012 to August 2013

- Coordinated with Southern California governments in drafting emergency plans for the Regional Catastrophic Preparedness Grant Program.

Ontario Office of Emergency Management, Ontario, California
Emergency Planner (Volunteer), February 2011 to January 2012

- Prepared emergency plans for the Western States Police and Fire Games.
- Assisted with Primary EOC design.
- Researched equipment and supplies for grant purchasing decisions.
- Instructed and Coordinated the Ontario Community Emergency Response Team.

Harris County Office of Homeland Security & Emergency Management, Houston, Texas
Community Liaison, August 2008 to February 2011

- Managed Community Preparedness and Outreach operations of ~30 multi-discipline staff.
- Represented the office during presentations on disaster preparedness and provided tours of the EOC to visiting dignitaries, diverse community groups and corporate interests.
- Served in multiple ICS Section Chief and Command Staff positions for various events and emergency incidents, including Joint Information Center (JIC) Manager/Assistant Public Information Officer for Harris County during Hurricane Ike operations.
- Maintained county situational awareness and successfully handled numerous incidents as member of On-Call/Watch Officer team.
- EOC Manager on multiple incidents.
- Helped plan and participate in public information function of local drills and exercises.
- Assisted with the development of Local Hazard Mitigation Action Plan.
- Responded to media inquiries, issued news releases and handled documentation during EOC activations.
- Managed implementation of OHSEM social media campaign.
- Produced regular reports for the director on organizational issues and activities.
- Assisted in supervision of OHSEM communications interns (2+)
- Appointed by University of Houston President and Chancellor to Blue-Ribbon Task Force on Safety & Security. Provided multiple active shooter incident recommendations.

Ponderosa Fire Department, Houston, Texas
Volunteer Firefighter, November 2007 to February 2011

- Responded with a team to save lives, preserve property, the environment and mitigate hazards during fires, motor vehicle accidents, hazmat incidents, rescues, natural disasters and other emergency events.

Harris County Judge Ed Emmett, Houston, Texas
Policy Analyst, April 2007 to August 2008

- Handled special projects for the chief executive officer as the liaison to County Fire Marshal, Harris County 9-1-1 System, Volunteer Fire Departments, Emergency Medical Services, Emergency Service Districts, GIS Task Force and the United States Census Bureau. Member, Harris County Safety Committee. Staff Member to Ethics Task Force.
- Brought together emergency service providers and the Public Infrastructure Department to implement an Emergency Vehicle Traffic Priority System.
- Managed a team of ten GIS specialists to review and update the address file as part of the Local Update of Census Addresses for the 2010 Census.

The Emmett Company, Houston, Texas
Manager, Campaigns, January 2006 to April 2007

- Managed or assisted with general election, primary election and special issue campaigns. Implemented strategy, conducted media buys, issued news releases, conducted issue research, coordinated and managed campaign and volunteer events and activities. Assisted with direct mail program and voter targeting.
- Supervised five direct reports.

Education

The University of Houston

- Bachelor of Science, Political Science
- Minor: Communications

FEMA – Emergency Management Institute

- National Emergency Management Basic Academy, Inaugural Class 2011
- National Emergency Management Advanced Academy, July 2016
- National Emergency Management Executive Academy, August 2018

Public Service

- Appointed, FCC Communications Security, Reliability and Interoperability Council, 2015-2017
- Awarded, President's Volunteer Service Award – Gold, 2011
- Member, Houston UASI Regional Public Information Plan Working Group, 2010-2011
- Member, UH President's Blue-Ribbon Task Force on Safety and Security, 2009
- Member, Greater Houston Partnership Aviation Committee, 2008
- Member, UH Police Department Training Provider Advisory Board, 2007-2011
- Member, UH Emergency Planning Committee, 2005

Affiliations (Past and Present)

- International Association of Emergency Managers
- California Emergency Services Association
- ASIS International
- InfraGard, Los Angeles Chapter
- Harris County Regional Joint Information Center Group

Q. Please state your name.

A. Daniel Garcia.

Q. What are your qualifications?

A. Please see the included CV following this page.

Q. What sections and the material contained therein are you sponsoring?

A. I am sponsoring Section II.C.3, Section II.C.4, and Section III.

Q. Was this material prepared by you or under your supervision?

A. Yes.

Q. Insofar as this material is factual in nature, do you believe it to be correct to the best of your knowledge?

A. Yes.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best professional judgment?

A. Yes.

DANIEL E. GARCIA

5249 Townsend Avenue, Los Angeles, CA 90041 ▪ (626) 379-6036 ▪ nadrag@sbcglobal.net

EDUCATION

Woodbury University
Bachelors of Science, Business & Management, *cum laude*

Los Angeles Mission College
Associate of Liberal Arts, Humanities

WORK EXPERIENCE

Assistant General Manager, Resources – Riverside Public Utilities *December 2017 to Present*

- Lead and Managed the RPU Resources Department (Wholesale Market Operations, Power Projects/Contracts, Resource Planning/Analytics, Power Generation, Customer Engagement, Public Benefits, Water Conservation, Communications, Office of Technology/Project Management and Legislative) of more than 100 represented (SEIU and IBEW) and non-represented, classified and non-classified employees. Manage an annual budget of more than $240 million
- Increased annual revenues by 46%, from $17.5M to $32M, through successfully advocating RPU's Transmission Revenue Requirement through CAISO
- Successfully managed the inclusion of the Historical Carryover provisions in the CEC's final Resource Portfolio Standard rules, for an estimated value to RPU ratepayers of $20M
- Modified CAISO tariff through FERC, resulting in RPU annual benefit in excess of $10M
- Successfully engaged in ongoing CAISO stakeholder initiatives advocating cost containment and cost causation principles for the benefit of RPU ratepayers
- Manage the replacement of over 70% of RPU's existing resource portfolio in a cost-effective method that meets renewable and GHG mandates while encouraging social justice
- Developed RPU energy portfolio consisting of 37% renewable resources – ahead of the 33% by 2020 state mandate.
- Manage public benefits fund for RPU, in excess of $14M per year

Market Operations Manager – Riverside Public Utilities *November 2009 to December 2017*

- Implemented market redesign and technology upgrade: Led development of data analytics capabilities in the Resources group. Developed and implemented new scheduling and deal capture software. Lead market operations in its development of Utility 2.0 Strategic Plan initiatives for Resources; Collaborated with the city to establish goals, policies, objectives, and developing measurements for success and WOW! Customer Service
- Successfully implemented RPU Cap-and-Trade program generating annual revenues of $9M/per year
- Developed successful strategy to avoid RPU's mandatory participation in California Air Resources Board's Cap-and-Trade activities, saving RPU ratepayers tens of millions of dollars per year
- Assisted water operations in negotiating solar pump station power purchase agreements
- Participate in development of utility policies, resource planning, resource evaluation and development of operating and risk management procedures and practices

Planning/Marketing Manager – Riverside Public Utilities *July 2008 to November 2009*

- Negotiated and drafted contracts for power purchases, transmission service, metered subsystems, renewable power and interconnection facilities
- Implemented effective and successful succession planning strategies to ensure seamless transition upon retirements of certain key positions
- Developed risk mitigation policies associated with resource procurement activities, including gas and energy price volatility
- Evaluated potential opportunities for power supply acquisition/optimization and power project participation; negotiate and administer contracts with various wholesale market participants to optimize power supply opportunities and resolve power supply issues

Utilities Power Trader – Riverside Public Utilities *July 2007 to July 2008*

- Forecasted near term system requirements; Prepared and issued daily, monthly and annual load schedules to meet system requirements
- Arranged for and pre-scheduled power load requirements with other resource agencies. Dispatched system power resources economically
- Maintained records, prepared electric load production and financial reports in monitoring system loads, and verified costs of power delivered by various suppliers

Power& Gas Procurement Manager – City of Vernon Light & Power *June 2005 to May 2007*

- Led the Resource Division of the Light and Power Department; managed resource procurement and trading (power and gas); Managed a budget of $70M; transmission and resource contract management; managed regulatory environment (FERC, CEC, DOE, CAISO), power generation, risk management, natural gas distribution, and scheduling and settlements; developed and executed organizational strategies for resource management, including transmission and distribution; managed matters regarding transmission contract negotiations and contract disputes
- Created a successful, new gas utility at the City of Vernon: managed litigation effort against SCE to secure a wholesale rate; managed regulatory process of new utility creation; created a wholesale rate schedule for new customer base; managed development of gas delivery infrastructure
- Managed FERC filings associated with the Department's transmission projects and associated ISO PTO status; negotiated the Department's Interconnection Agreement with SCE; negotiated the Metered Subsystem Agreement with CAISO; managed agreements for the Mead-Phoenix, Mead Adelanto and COTP transmission projects; key participant in the issuance of $269M bond for the construction of the Malburg Generating Station

Bulk Power Manager – City of Vernon Light & Power *July 2003 to June 2005*

- Managed integrated resource portfolio for the Light and Power Department; executed organizational strategies for long-term power resource procurement
- Managed all scheduling and settlement activities

Current/Former Committee/Board Representation

- Power Agency of California, President
- American Public Power Association, Member
- California Municipal Utilities Association, Board Member
- San Onofre Nuclear Generating Station, Executive Committee
- Intermountain Power Agency – Coordinating, Executive Committees
- Southern California Public Power Authority, Board of Directors
- Western System Power Pool, Operating Committee
- Western Electricity Coordinating Council, Operating Committee
- Mead-Phoenix Project, Coordinating Committee
- Mead-Adelanto Project, Management Committee
- Hoover Project. Engineering and Operations, Contractors Committees
- Riverside Public Utilities, Risk Management Committee Member
- American Power Dispatchers Association, Member

Q. Please state your name.

A. My name is George Hanson.

Q. What are your qualifications?

A. Please see the included CV following this page.

Q. What sections and the material contained therein are you sponsoring?

A. I am sponsoring Section II.A, Section II.C.1(g), Section II.C.2.

Q. Was this material prepared by you or under your supervision?

A. Yes.

Q. Insofar as this material is factual in nature, do you believe it to be correct to the best of your knowledge?

A. Yes.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best professional judgment?

A. Yes.

George R. Hanson

951-545-0048 ● georgehanson21@gmail.com

Objective

Advance my career in an executive position that will allow me to use my experience, professional skills, and leadership abilities to successfully guide Riverside Public Utilities through the challenges facing municipal utilities today while meeting and exceeding goals.

Professional Experience

January 2017 to Present

Riverside Public Utilities, City of Riverside— Assistant General Manager/Energy Delivery and Executive Team member responsible for development and implementation of corporate strategy and policy for RPU. AGM responsible for all Energy Delivery functions for organization comprised of approximately 225 employees. AGM responsible for engineering, construction, maintenance, and operation of city's electric, street light, and communications systems.

August 2013 to April 2014

Riverside Public Utilities, City of Riverside—Electric Field Manager responsible for construction and operation/maintenance of overhead and underground electrical distribution facilities. Managing 70+ staff made up of IBEW, SEIU, and Management employees and an annual budget of $14MM. Manager responsible for Contract Administration for construction activities, asset management, line clearing, inspection, and streetlights. Participated in Labor Management. Led the successful recruitment or promotion of several hard-to-fill positions.

June 2010 to August 2013 then June 2014 to December 2016

Riverside Public Utilities, City of Riverside—Engineering Manager responsible for technical support of energy delivery functions including System Planning/Protection, Substation Engineering, Communications, Major T&D Projects, and Customer Engineering for 107,000+ meter customer base covering a service territory of 84 square miles. Managed staff of 68 and an annual budget of $60MM. Manager responsible for permitting, licensing, designing, and constructing new 230kV transmission line, switchyard, and substation for City of Riverside - a project estimated at more than $400MM.

Accomplishments:

- Riverside Transmission Reliability Project – directed and led project team through environmental phase involving coordination with broad range of stakeholders
- Led the department's labor management effort with IBEW's 200+ members
- Led internal team responsible for acquiring SCE assets in annexed areas
- Led Energy Delivery development and input for Utility 2.0 Strategic Plan
- Responsible Manager for preparation of application to APPA that resulted in RPU's recognition as Reliable Public Power Provider (RP3) Platinum level in 2011, and Diamond level in 2014 and 2017
- Represented RPU at Southern California Public Power Authority's Engineering/Operations Comm.

Professional Experience (continued)

January 2007 to June 2010

City of Moreno Valley—Electric Utility Division Manager responsible for all aspects of electric utility including procurement of wholesale power and field service operations. Managed team of 20 people and participated as part of city's team regarding $25MM financing for the development and construction of a critical substation and related improvements for the city's electric distribution system. Successfully improved reliability for customer base that grew by more than 10% per year.

Accomplishments:

- Led the negotiation and permanent settlement with the Southern California Edison for Departing Load Charges (exit fees) on behalf of the City resulting in more than $5 million in savings
- Directly oversaw development, construction, and commissioning of a 115kV Switchyard/Substation
- Led successful, favorable settlement of litigation with City's contract utility operator
- Directly oversaw and managed the construction of more than five miles of 12kV distribution feeders
- Founded and acted as Chairman of the New Municipal Utility Committee (part of CMUA)

April 2001 to December 2006

City of Corona Dept. of Water & Power – Assistant General Manager responsible for all aspects of electric utility and service operations including procurement of wholesale power, resource development, regulatory affairs, public affairs, customer service, energy efficiency, energy delivery and revenue cycle services. Managed and led a team of 75 employees. Also responsible for strategic planning, development, technical oversight and operations for Water and Wastewater enterprises.

Accomplishments:

- Within six months of hire at Corona, started the municipal utility and took it from zero electric utility business functions to a CPUC registered Electric Service Provider (ESP) that had initial annual revenue of $15MM
- Established the city as a registered ESP within three major utility (UDC/IOU) service territories
- Developed, implemented, promoted, and managed electric service to more than 1,400 Commercial and Industrial customers comprising approximately 35 megawatts (MW) of peak load
- Developed, administered, and managed a departmental operational budget in excess of $25MM
- Led the development of the Clearwater Power Plant, a nominal 30 MW, combined cycle, natural gas fueled cogeneration plant that is integrated with a biosolids drying unit – power plant began commercial operations in 2005 (RPU acquired Clearwater Power Plant in September 2010)
- Developed, energized to the local area grid, and managed Corona's electrical distribution projects and direct access customers throughout the city (oversaw design, construction, and commissioning of six distribution substations) requiring extensive coordination with SCE
- Participated as a member of the Transmission Dependent Section responsible for developing a nomination to Governor Schwarzenegger for a CAISO Board vacancy in December 2005, and again in December 2007
- Testified in proceedings at both FERC and CPUC on electric utility matters
- Negotiated more than two dozen operating agreements vital to the success of the new utility

Professional Experience (continued)

June 1991 to April 2001

Southern California Edison – Account Manager responsible for major customer accounts representing over $50MM in annual revenue. Responsibilities included acting as single point of contact with large customers regarding all business issues, outage management, presentations to large groups, anti-municipalization efforts, customer education regarding deregulation, and other assignments as required. Held various other management positions including New Construction Representative, Technical Support Engineer, as well as various engineering roles at San Onofre Nuclear Generating Station (SONGS).

Education/Licenses/Certifications/Affiliations

Bachelor of Science, Civil Engineering, University California Irvine
Master of Science, Civil Engineering, California State University Long Beach
Registered Professional Civil Engineer (PE) in California
Southern California Public Power Authority – Past chair of T&D E&O Committee
Assoc. of Energy Engineers - Certified Energy Manager/Energy Procurer
American Public Power Association
California Municipal Utility Association – member of Board of Governors from 2007-2010
Western Energy Institute – Business Acumen for Emerging Leaders, Class of 2013
California Utilities Emergency Association – member of Board of Directors from 2017-2018
Crafton Water Company – current member of the Board of Directors

Professional References

Stan Stosel, Sr. Asst. Business Manager, IBEW Local 47 – (909) 260-3686
Steve Badgett, City of Riverside (ret.) – (951) 231-4487
Bob DeKorne, Sr. VP, ENCO Utility Services – (909) 289-5427
Kathy Michalak, Exec. Director, Habitat for Humanity Riverside – (951) 787-6754
Don Boland, Director, Calif. Utilities Emergency Association – (916) 845-8518
Greg Irvine, Asst. City Manager, Corona (ret.) – (951) 515-7642

Q. Please state your name.
A. Scott Lesch, Ph.D.
Q. What are your qualifications?
A. Please see the included CV following this page.
Q. What section and the material contained therein are you sponsoring?
A. I am sponsoring Section II.B.
Q. Was this material prepared by you or under your supervision?
A. Yes.
Q. Insofar as this material is factual in nature, do you believe it to be correct to the best of your knowledge?
A. Yes.
Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best professional judgment?
A. Yes.

Name: **Dr. Scott M. Lesch**
Power Resources Manager
Resource Planning & Technology Integration Unit
Riverside Public Utilities – Resources Division

Positions:

Power Resources Manager	Jan 2014 – Present
Utility Principal Resource Analyst	Aug 2012 – Dec 2013
Utility Senior Resource Analyst	Nov 2009 – Jul 2012

Resources Division
Riverside Public Utilities
3435 14th St., Riverside, CA 92501
(951) 826-8510
slesch@riversideca.gov

Principal Consulting Statistician	Jan 2007 – Nov 2009

UC Riverside Statistical Collaboratory
2683 Statistics-Computer
900 University Ave., Riverside, CA 92521
University of California, Riverside Campus

Principal Statistician:	Apr 2000 – Jan 2007
Senior Statistician:	Dec 1991 – Apr 2000
Staff Research Associate:	Nov 1988 – Dec 1991

USDA - ARS – GEBJ Salinity Laboratory
450 W. Big Springs Rd., Riverside, CA, 92507
Cooperative Employee, University of California, Riverside
Department of Soil & Environmental Sciences

Lead Analyst, Owner:	1996 – 2003

Environmental Statistical Services

Education:

Ph.D.	Applied Statistics, University of California, Riverside (2007)
M.S.	Statistics, Carnegie Mellon University (1988)
B.S.	Statistical Computing, University of California, Riverside (1987)

Expertise:

Power Resource Planning / Utility Analytics: short & long-term utility load forecasting, resource planning and acquisition, CAISO market analytics and optimization strategies, CAISO CRR bidding optimization, hedging implementation strategies, risk management – including assessment of legislative and regulatory risks.

Data Analytics: linear and nonlinear modeling techniques, forecasting & time series analysis, spatial statistics, experimental design, survey sampling, simulation techniques, operations analysis and mathematical optimization techniques.

Statistical Consulting / Technical Writing: extensive consulting experience in both commercial and academic environments; advanced technical report writing skills; 25 years of experience developing technical manuscripts for academic journals (author or coauthor on 75+ manuscripts, first author publication list attached); 10 years of experience developing technical utility reports, lead manager and technical author for 2014 and 2018 RPU Integrated Resource Plans.

Scientific Software Development: advanced programming experience using Excel, Visual Basic and the SAS platform; custom GUI (Windows 98/NT/XP) development for end-user software applications; custom SAS Base and SAS IML applications for modeling and simulating the CAISO energy market; advanced knowledge of the Ascend Analytics portfolio modeling software platforms (PowerSimm Software Suite and Curve Developer Software).

Environmental/Agricultural Monitoring & Surveying Applications: soil salinity surveying via EM (electromagnetic induction) technology; optimal agricultural water management strategies, sampling & analysis techniques for environmental and agricultural research / demonstration projects.

Professional Experience:

Riverside Public Utilities (2014 – Present)

Power Resources Manager (Resource Planning & Technology Integration Unit) in the RPU Power Resources Division. Manage and supervise 10 utility staff responsible for all load forecasting activities, integrated resource planning studies, portfolio modeling software applications, CAISO market analytics, CEC and CARB regulatory monitoring, new power resource initiatives (TE and EV planning, DER impacts, etc.), and new software technology integration activities across the utility. Provide lead technical support for new project/contract evaluations; supervise and oversee all hedging and risk management recommendations for the RPU Risk Management Committee; supervise the Power Resources Regulatory and Cyber-security Working Groups; supervise the staff responsible for implementing the SAS and OSI-Pi Software platforms across the utility.

As directed by Executive Management, provide specific analytical or technical assessment of critical issues impacting the utility. Supervise all Integrated Resource Planning activities and serve as the lead manager and technical author of the IRP. Manage and oversee the development of the annual power supply budget, including the derivation of all budget forecasts. Coordinate staffing needs for new analytical initiatives and/or ad-hoc analytical studies. Assist Executive Management with strategic planning exercises related to utility analytics and specific operational technology initiatives; perform and/or administer other Assistant General Manager division duties as needed (when the AGM of Power Resources is traveling or unavailable).

Riverside Public Utilities (2009 – 2013)

Principal and Senior Resource Analyst (Quantitative Analyst) in the RPU Power Resources Division. Acted as lead technical analyst for all load forecasting activities, power planning and portfolio modeling software applications, and CAISO market analytics. Provided additional technical support for new project / contract evaluations, hedging and risk management activities, and regulatory monitoring activities. More specific duties performed in each functional area are described below:

Load Forecasting: Develop (1) monthly gross load, peak load and class-specific retail load models (econometric models) for long term planning and forecasting activities (1-15 years forward), (2) hourly load forecasting models for use by Market Operations and Energy Delivery, and (3) RPU electric sales & revenue forecasting/tracking tools for use by Finance to quantify monthly and annual RPU retail sales & revenue projections. Identify factors affecting City loads and related impacts on load growth; summarize and synthesize results for upper management. Develop and maintain retail water sales and revenue forecasting equations for the Water Department, project future sales and revenues under different retail rate scenarios and/or economic conditions.
Power Resource Budgeting: Perform the annual calibration and forecast of 5-year and 10-year forward wholesale RPU power costs. Specify and identify all power resource budget inputs, forward market assumptions, and load metrics. Validate all output metrics; assess multiple

resource acquisition scenarios to determine the least cost, least risk strategies for acquiring new power resources to meet RPU load growth forecasts and regulatory/renewable mandates. Assume primary role for the development, implementation, supervision and maintenance of all RPU production cost modeling software systems.
New Project / Contract Evaluation: Identify and assist in the negotiation and evaluation of new power resource contracts; analytically assess contract provisions and recommend desirable modifications to optimize benefits and minimize costs. Negotiate and implement all analytical software and production cost modeling contracts; interact with and supervise external consultants tasked to implement new software tools and/or systems for the Resources Division.
CAISO Market Analytics: Perform detailed statistical analyses of CAISO market information; i.e., assess and identify structural relationships between SP15 hourly energy prices, daily natural gas prices, and SP15 forward energy and gas curves. Develop and implement forward strategies to enhance and optimize the City's position in the CAISO market, following acceptable risk management guidelines. Analyze and optimize algorithms for simulating the economic dispatch of our internal generation in the CAISO market, assist in the development of bidding strategies (in both DAM and HASP market) for RPU power resources. Develop statistical methodologies to model and value congestion patterns on primary source-sink paths and convert these statistical distribution functions into optimal CRR bid curves.
Hedging & Risk Management: Assist in the development and implementation of cost effective hedging strategies to protect the City's financial exposure in the energy and natural gas markets. Perform monthly (prompt-month) energy position assessments and 1-4 year forward hedging assessments, develop recommendations for re-structuring, optimizing and/or hedging loads and resources. Track and document all results for upper management and the Risk Management Committee.
Regulatory Monitoring Activities: Monitor and assess the CEC rulemaking process for implementing all renewable energy (RPS) mandates; recommend cost effective compliance strategies for meeting all City and state renewable targets. As directed by upper management, track and monitor relevant CAISO and CARB market initiatives related to resource planning, market operations, and regulatory compliance. Assist with and participate in SCPPA and CMUA technical assessment activities of new regulatory mandates.

UC Riverside Statistical Collaboratory (2007 – 2009)
(www.collaboratory.ucr.edu)

Consulting statistician and technical project manager for the Statistical Consulting Collaboratory (a dedicated UCR-CNAS consulting center supplying data analysis services to UCR faculty and off-campus commercial clients). Primary job responsibilities included (i) technical management of all collaborative Agricultural, Environmental and Natural Science research projects, (ii) developing new off-campus commercial and/or government funded projects and statistical consulting activities, (iii) assisting on and/or leading in the formation and development of cooperative grant writing activities, (iv) providing consulting related teaching support in the Statistics department, and (v) providing guidance and supervision to graduate Statistics students engaged in Collaboratory sponsored research and/or consulting activities. Responsible for the development and promotion of statistical consulting activities associated with off-campus commercial clients, including assuming the role as the lead technical project manager for any commercial projects brought into the Collaboratory. Typical commercial projects handled by the Collaboratory were diverse in nature, but arose primarily from the fields of biology and medicine, finance and mortgage lending, marketing, environmental monitoring, risk management and industrial quality control.

Additional duties included coordinating advanced SAS training seminars and instructional workshops for the Statistics department graduate students, offered through the department's Stat-293 graduate consulting course.

GEBJ Salinity Laboratory (1988 – 2007)

Principal consulting statistician and programmer/analyst for the scientific research staff at the U.S. Salinity Laboratory. Responsible for (i) providing all statistical analysis of data arising from soil and/or crop experiments and observational studies, (ii) recommending, developing and implementing appropriate statistical methodologies, modeling techniques and/or sampling designs for both field and bench (laboratory) studies, and (iii) providing written documentation of all statistical results and follow-up support. Assisted in the writing of both internal and external (peer reviewed) technical manuscripts; developed internal statistical training seminars (for laboratory staff) as needed. Provided expertise in the monitoring and assessment of spatial soil salinity patterns (field & regional scale) via EM techniques, statistical analysis of crop response data subject to environmental stress (salinity, water stress, boron toxicity, nutrient deficiency), and the development of model-based environmental sampling strategies.

Additional job duties included custom software development and the implementation and coordination of technology transfer and technical outreach programs. Responsible for the original development of the ESAP Software Suite, a comprehensive Windows software package for the assessment, inventorying, and monitoring of spatial soil salinity levels using EM or 4-electrode technology. Co-founder and past technical program manager of the Lower Colorado Region Salinity Assessment Network; a jointly sponsored (USDA-ARS and USBR) salinity assessment network throughout the lower Colorado region dedicated to salinity control and water conservation. Invited Instructor for the USDA-NRCS Salinity Management Training courses held throughout the western United States from 2005 to 2008.

Environmental Statistical Services (1996 – 2003)

Independent statistical contracting work, sample business clients highlighted below:

1996-1997: Tetra Tech, Inc: San Bernardino Office, March AFB Groundwater Modeling

Developed spatial / temporal statistical analysis techniques for quantifying the degree and magnitude of groundwater contamination at March Air Force Base, CA. Primary responsibilities included (1) devising statistical techniques for determining the effects of different ground water well sampling procedures and varying analytical laboratory procedures on the temporal organic chemical concentration levels, and (2) developing statistical modeling procedures for quantifying the degree of organic chemical plume migration and spatial / temporal flux.

1998-2001: Tetra Tech, Inc: San Diego Office, EPA SITE Contract

Lead contract statistician for 50 million dollar SITE (Superfund Initiative Technology Evaluation) contract. Responsible for the development and/or review of all statistical modeling and analysis techniques presented in each Quality Assurance Project Plan (QAPP) submitted to EPA. Developed and reviewed approximately 6 to 10 projects per year; the majority of which focused on demonstrating and quantifying innovative clean-up technologies for contaminated soil or groundwater. Responsible for the analysis of all experimental data, interpretation of statistical results, and submission of written documentation for inclusion into all EPA QAPP's and final project reports.

2000-2003: Soil & Water West: Owens Lake Salinity Assessment Program

Contract statistician for basin-wide spatial salinity assessment program at Owens Lake, CA. Primary responsibilities included the development and implementation of appropriate EM surveying techniques, statistical analysis and modeling of spatial-temporal EM/salinity data, design of salinity monitoring programs for experimental re-vegetation studies, and assistance in the assessment of various water quality issues relating to the planned dust abatement program and partial reclamation of the lakebed.

First Author Publication List:

Lesch, S.M., and Jeske, D.R. 2013. A new Exponential GOF test for Data subjected to Multiply Type II Consoring. Communications in Statistics: Theory & Methods, 42: 1-19.

Lesch, S.M. 2012. Statistical models for the prediction of field scale, spatial salinity patterns from soil conductivity survey data. Chapter 14 (pp 461-482), ASCE Salinity Manual 71, 2nd Ed, Am. Soc. Civil Engineers, Reston, Virginia.

Lesch, S.M., and Jeske, D.R. 2009. Some suggestions for teaching about Normal approximations to Poisson and Binomial distribution functions. The American Statistician, 63: 274-277.

Lesch, S.M., and Suarez, D.L. 2009. A short note on calculating the Adjusted SAR Index. Trans. of the ASABE, 52: 493-496.

Lesch, S.M., and D.L. Corwin. 2008. Prediction of spatial soil property information from ancillary sensor data using ordinary linear regression: Model derivations, residual assumptions and model validation tests. Geoderma, 148: 130-140.

Lesch, S.M., Arnold, B.C., and D.R. Jeske. 2009. Simple and accurate approximations for computing covariance matrices of Gamma and Weibull order statistics. Communications in Statistics: Sim & Comp., 38: 590-609.

Lesch, S.M., D.L. Corwin and D.A. Robinson. 2005. Apparent soil electrical conductivity mapping as an agricultural management tool in arid zone soils. Comp & Electron in Ag, 46: 351-378.

Lesch, S.M. 2005. Sensor-directed spatial response surface sampling designs for characterizing spatial variation in soil properties. Comp & Electron in Ag, 46: 153-180.

Lesch, S.M. and D.L. Corwin. 2003. Using the dual-pathway parallel conductance model to determine how different soil properties influence conductivity survey data. Agron. J. 95:365-379.

Lesch, S.M., J.D. Rhoades and D.L. Corwin. 2000. The ESAP-95 version 2.01R user manual and tutorial guide. USSL Research Report No. 146.

Lesch, S.M., J. Herrero and J.D. Rhoades. 1998. Monitoring for temporal changes in soil salinity using electromagnetic induction techniques. Soil Sci. Soc. Am. J. 62(1):232-242.

Lesch, S.M., D.J. Strauss and J.D. Rhoades. 1995. Spatial prediction of soil salinity using electromagnetic induction techniques: 1. Statistical prediction models: A comparison of multiple linear regression and cokriging. Water Resour.Res. 31:373-386.

Lesch, S.M., D.J. Strauss and J.D. Rhoades. 1995. Spatial prediction of soil salinity using electromagnetic induction techniques: 2. An efficient spatial sampling algorithm suitable for multiple linear regression model identification and estimation. Water Resour.Res. 31:387-398.

Q. Please state your name.
A. Chief Jennifer McDowell.
Q. What are your qualifications?
A. Please see the included CV following this page.
Q. What section and the material contained therein are you sponsoring?
A. I am co-sponsoring Section II.C.1(f) with Mark Annas.
Q. Was this material prepared by you or under your supervision?
A. Yes.
Q. Insofar as this material is factual in nature, do you believe it to be correct to the best of your knowledge?
A. Yes.
Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best professional judgment?
A. Yes.

Jennifer Irene McDowell

1542 Century Dr.• Riverside, CA 92506

Phone: Work 951 5321 Mobile 951-233-9875 • E-Mail: JMcdowell@riverside.gov

OBJECTIVE

To sponsor testimony for RTRP on behalf of the Riverside Fire Department.

SUMMARY OF QUALIFICATIONS

27 Years of Professional Fire Service Experience

As the Fire Marshal I oversee the Fire Prevention Division, supervising over 10 staff members who currently enforce the 2016 California Fire, Building, Electrical, Mechanical, Plumbing and Residential Codes, as amended by the Riverside Municipal Code, in addition to National Fire Protection Association standards; Title 19, of the California Public Safety Code; and the California Health and Safety Code. I manage our division's budget; work with our cities elected officials; support our community by educating them on our programs and processes I oversee; work with other agencies in the city to ensure safety and compliance is adhered to; and also work with local, State and Federal agencies on various projects that pertain to our cities development projects, risk assessment, strategic plan and local hazard mitigation plan.

At times I am responsible for the overall supervision of company operations; responding to emergency scenes; extinguishing and controlling fires; handling hazardous materials situations; providing rescue and emergency medical care; performing scene size-up to determine the most effective, efficient, and safe use of personnel, equipment and apparatus to control fire and emergency situations; delivering a broad based fire prevention program; and providing community services as deemed appropriate for the fire/rescue service.

EXPERIENCE

Division Chief / Fire Marshal	2016 to present
Battalion Chief / Operations	2014 to 2016
Captain / Training Fire Captain	2004 to 2014
Fire Engineer / Level I- Fire Investigator	2002 to 2004
Firefighter	1994 to 2002
Seasonal Firefighter, Cal Fire/ San Bernardino & Riverside County	1992 to 1994

ACADEMIC EDUCATION

Bachelor of Science	Occupational Studies, Cal State University, Long Beach	2007
Associate of Arts	Fire Administration, Santa Ana College	2005
Associate of Arts	Interior Design, Los Angeles City College	1986

PROFESSIONAL EDUCATION

Executive Chief Fire Officer	California State Fire Marshal	2019
Executive Fire Officer	National Fire Academy	2014
Certified Chief Officer	California State Fire Marshal	2005
Certified Fire Officer	California State Fire Marshal	1997

PROFESSIONAL ORGANIZATIONS

Riverside Fire Prevention Officer / Co-Chair	2017 to present
Riverside County Training Officers Association, President	2010 to 2011
Southern California Training Officers, Second Vice President	2012 to present
State Fire Training Cadre, Member	2013

Q. Please state your name.

A. Bob Tang, Ph.D.

Q. What are your qualifications?

A. Please see the included CV following this page.

Q. What sections and the material contained therein are you sponsoring?

A. I am sponsoring Section I and Section II.C.1 - II.C.1(e).

Q. Was this material prepared by you or under your supervision?

A. Yes.

Q. Insofar as this material is factual in nature, do you believe it to be correct to the best of your knowledge?

A. Yes.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best professional judgment?

A. Yes.

HSI BANG (BOB) TANG
(626) 823-2588 (Cell)
bob.tang61@hotmail.com

PROFESSIONAL EXPERIENCE:

Independent Consultant – President - HBT Energy Management LLC

January 2017 to present

Areas of Expertise:

- Energy risk management and hedging strategies
- Energy contract dispute resolution, negotiation and administration
- Economic evaluation of energy resources
- CAISO markets
- Preparation of energy contracts and regulatory filings for clients' special projects

Power Resources Manager - Contracts/Projects/Planning Manager – Riverside Public Utilities, California

September 2009 to August 2016

Primary Areas of Responsibility:

- Oversee long term power resource planning and procurement for Riverside Public Utilities (RPU) including conventional and renewable resources;

- Oversee the administration of Riverside Public Utilities (RPU) existing power resource contracts and projects;

- Negotiate wholesale power contracts for conventional and renewable resources on behalf of RPU, e.g., long term solar PV PPAs with SunEdison and Silverado, long term geothermal PPA with Salton Sea, long term PPA with WKN wind project, short term PPA with Covanta for biomass energy etc..;

- Oversee the development and implementation of RPU's conventional and renewable resources, e.g., RPU's acquisition of Clearwater Power Plant from the City of Corona, the implementation of 6-MW WKN wind project, the RFP process for local solar PV project - Tequesquite;

- Oversee the development of strategic resource plan to achieve Renewable Portfolio Standard goals for RPU;

- Lead manager in market and regulatory matters related to California Independent System Operator (CAISO), Federal Energy Regulatory Commission (FERC), California Energy Commission (CEC) and California Air Resources Board

(CARB), most recent achievement – the resolution of munis' use of CARB allocated allowances under the Cap-and-Trade program via CAISO tariff amendment;

- Oversee the wholesale power transaction settlement functions related to third party transactions and CAISO transactions;

- Oversee the preparation of RPU's Transmission Revenue Requirement and annual transmission related regulatory filings with FERC;

Assistant Director - Resource Management – Azusa Light and Water, California 2002 to August 2009

Primary Areas of Responsibility:

- Oversee the electric utility's energy trading; power scheduling and wholesale power transaction settlement activities;

- Oversee the negotiation and the administration of wholesale power supply, transmission service and other related contracts; serve as the representative for Azusa Light and Water in project management committees in joint power generation and transmission projects;

- Oversee the electric utility's long term power resource planning and procurement activities including conventional and renewable energy resources;

- Oversee state and federal legislative and regulatory monitoring and compliance activities pertaining to electric and water utilities; develop strategic options; implement options/recommendations to position Azusa Light and Water favorably in the fast changing utility business; serve as Azusa Light and Water representative with other energy companies and regulatory agencies;

- Oversee the financial planning activities of Azusa Light and Water including the preparation of annual and five-year financial forecasts; the development of long term strategic financial plans and policies; conduct retail rate studies and proceedings; serve as the lead for Azusa Light and Water with financial institutions and rating agencies;

- Acting in Director of Utilities' absence in overseeing Azusa Light and Water operations

Manager of Integrated Resource Planning – Azusa Light and Water, California 1994 to 2001

Primary Areas of Responsibility:

- Oversee the negotiation and the administration of electric utility's power supply, transmission service and other related contracts;

- Oversee the planning and the implementation of energy efficiency and conservation programs;

- Oversee the electric utility's energy trading; power scheduling and wholesale power transaction settlement activities;

- Serve as Azusa Light and Water representative in technical committees in joint power generation projects and transmission projects;

- Serve as Azusa Light and Water representative in technical committees that established the California Independent System Operator (CAISO) market structure

Associate Power Engineer – Vernon Light and Power, California
1991 to 1994

Primary Areas of Responsibility:

- Implementation of Time-of-Use rates for commercial and industrial customers

- Implementation of commercial and industrial energy efficiency and conservation programs

- Perform technical and economic analysis in support of power resources development and contract negotiation

EDUCATION:

PhD in Electrical Engineering - University of California at Los Angeles, California, 1991

Major in control theory applied to electric power systems; operations research; and applied mathematics

Master of Science in Electrical Engineering – University of California at Los Angeles, California, 1986

Major in control systems and electric power systems

Bachelor of Science in Electrical Engineering – Escola Politecnica of Sao Paulo, Brazil, 1984

Major in electrical engineering – electric power systems