2014 POWER SUPPLY INTEGRATED RESOURCE PLAN

City of Riverside

Riverside Public Utilities

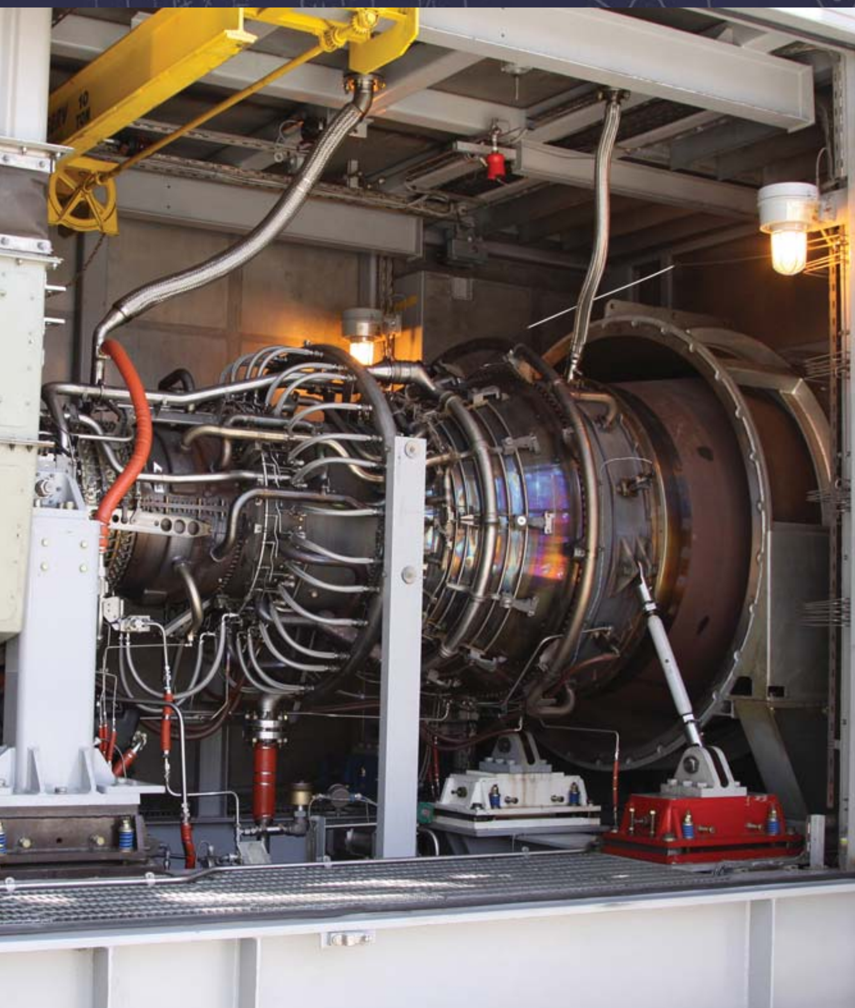
Resources Division

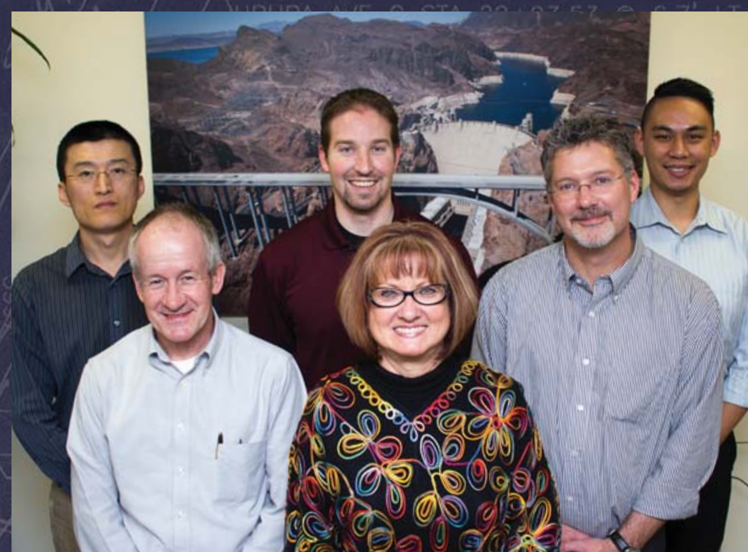
WATER | ENERGY | LIFE

CITY OF RIVERSIDE

PUBLIC UTILITIES

Riverside Public Utilities
Administration
3750 University Avenue, 3rd Floor • Riverside, CA 92501
951.826.2135 • RiversidePublicUtilities.com





RiversidePublicUtilities.com

WATER | ENERGY | LIFE

CITY OF RIVERSIDE

PUBLIC UTILITIES

City of Riverside

Riverside Public Utilities

Our Mission

The City of Riverside Public Utilities Department is committed to the highest quality water and electric services at the lowest possible rates to benefit the community.

Our Ten-Year Vision

Our customers will recognize Riverside Public Utilities as a unique community asset with a global reputation for innovation, sustainability and an enhanced quality of life.

Our Core Values

The City of Riverside Public Utilities Department values...

- Safety
- Honesty and Integrity
- Teamwork
- Professionalism
- Quality Service
- Creativity and Innovation
- Inclusiveness and Mutual Respect
- Community Involvement
- Environmental Stewardship

2014 Power Supply Integrated Resource Plan

December 29, 2014

Riverside Public Utilities

Resources Division, Planning & Analytics Unit

Reiko A. Kerr

Assistant General Manager – Resources Division

Scott M. Lesch

Resources Manager – Planning & Analytics Unit

2014 IRP Primary Team Members (Planning & Analytics Unit)

Scott M. Lesch – Resources Manager

Jeff Leach – Senior Resource Analyst

Qiang Chen – Resource Analyst

Additional contributions from the following personnel are graciously acknowledged:

Bob Tang – Resources Manager, Projects/Contracts Unit

Philip Fernandez – Senior Resource Analyst, Planning & Analytics Unit

Alan Woodcock – Principal Analyst, Planning & Analytics Unit

Alexander Lauderbaugh – Energy Analyst, Ascend Analytics

Abstract

The *2014 Power Supply Integrated Resource Plan* ("IRP") provides an impact analysis of, as well as the types and timing related to, Riverside's acquisition of new power resources, and the effect these resources will have on Riverside Public Utilities future projected cost of service in the 2014-2033 timeframe. Both intermediate term (5-year forward) and longer term (20-year forward) resource portfolio and energy market issues are examined in this IRP. Our intermediate term analyses examine our near-term (a) projected capacity and resource adequacy needs, (b) renewable portfolio standard (RPS) mandates, (c) carbon emission goals and mandates, (d) power resource budgetary objectives, and (e) cash-flow risk metrics. The primary longer term issues examined in this IRP include (a) projected load growth impacts, (b) timing impacts associated with the termination of our Intermountain Power Project (IPP) contract, (c) how market price shocks could impact our resource portfolio, (d) potential replacement options for our IPP contract, and (e) potential changes in future RPS mandates.

Table of Contents

List of Tables

List of Figures

Executive Summary

This *2014 Power Supply Integrated Resource Plan* ("IRP") provides an impact analysis of, as well as the types and timing related to, Riverside's acquisition of new power resources, and the effect these resources should have on Riverside Public Utilities future projected cost of service during the 2014-2033 time period. Both current and proposed Supply Side and Demand Side resources are examined in detail, towards a goal of continuing to provide the highest quality electric services at the lowest possible rates to benefit our local community, and subject to Riverside's procurement decisions meeting a diverse set of state and regional legislative / regulatory mandates. The five primary goals of this IRP can be broadly summarized as follows:

- Goal 1. Provide an overview of Riverside's (a) energy and peak demand forecasts, (b) current generation and transmission resources, and (c) existing electric system.

- Goal 2. Review and assess the impact of important legislative and regulatory mandates imposed by various state or regional agencies (California Energy Commission, California Air Resources Board, South Coast Air Quality Management District, etc.), along with the impact of important active or proposed California Independent System Operator (CAISO) stakeholder initiatives.

- Goal 3. Summarize and assess our current set of Energy Efficiency (EE) and Demand Side Management (DSM) programs, and examine if and how these EE/DSM programs can be further expanded to help offset our future energy needs.

- Goal 4. Quantify our expectations and uncertainty around our intermediate term (five-year forward) power resource forecasts, specifically with respect to meeting our (a) projected capacity and resource adequacy needs, (b) renewable portfolio standard (RPS) mandates, (c) carbon emission goals and mandates, (d) power resource budgetary objectives, and (e) cash-flow risk metrics.

- Goal 5. Examine and analyze certain critical longer term power resource issues, specifically with respect to how these issues are forecasted to impact our future cost-of-service. The primary longer term issues examined in this IRP include (a) projected load growth impacts, (b) timing impacts associated with the termination of our Intermountain Power Project (IPP) contract, (c) general market price shock impacts (i.e., sensitivity analyses), (d) potential replacement options for our IPP contract, (e) cost impacts associated with higher RPS mandates, and (f) value and/or cost analyses of important secondary issues (e.g., energy storage, customer solar PV, electric vehicles, etc.).

The chapter organization and layout sequentially follows the general goals discussed above. More specifically, background information is presented in Chapters 2-4, legislative and regulatory mandates and initiatives are discussed in Chapter 5, our EE and DSM programs are discussed in Chapter

6, forward market views are presented in Chapter 7, RPU intermediate term portfolio forecasts are discussed in detail in Chapter 8, and multiple longer term resource planning issues are analyzed in Chapters 9-13. Additionally, Chapter 14 presents a comprehensive summary of our findings.

Succinct summaries of our findings with respect to these five overriding goals are presented below.

RPU Background Information

An overview of RPU's long-term energy and peak demand forecasting methodology is presented in Chapter 2. This overview includes a discussion of our econometric forecasting approach, key input variables and assumptions, and pertinent model statistics. In Chapter 3 we provide an overview of RPU's long term resource portfolio assets, including our existing resources, future renewable resources (currently under contract), and recently expired contracts. We also describe our transmission resources, along with our transmission control agreements with the CAISO. Finally, in Chapter 4 we briefly review RPU's existing electric distribution system and describe how it operates. The key highlights from these background chapters are as follows:

- ✓ Our econometric forecasting models have been used to produce both high (strong) and low (weak) 2014-2033 output energy and peak demand forecasts. These forecasts call for our system loads to grow between 0.5% to 2.4% annually and our peak demand to grow from 0.5% to 1.1% annually, over the next 20 years.

- ✓ RPU currently either owns or has contracts for seventeen different generation resources that are based on multiple types of thermal or renewable technologies. Altogether, our current resource portfolio provides RPU with about 550 MW of nameplate capacity; within the next two to three years this number should increase to about 656 MW of capacity, as new renewable resources come online.

- ✓ RPU is a vertically integrated utility that operates electric generation, sub transmission, and distribution facilities; receiving the vast majority of its system power through the regional bulk transmission system operated by the CAISO. Undoubtedly, the Riverside Transmission Reliability Project (RTRP) represents the most important anticipated change to our distribution system. If RTRP is fully adopted, SCE will expand its regional electrical system to provide Riverside a second source of transmission capacity to import bulk electric power, which in turn could significantly alter our long-term internal resource procurement needs.

Important Legislative and Regulatory Mandates

In Chapter 5 we review and discuss relevant legislative, regulatory and stakeholder issues that will significantly impact the California electric energy industry in the foreseeable future, specifically the markets run by the CAISO. In particular, the following legislative, regulatory, and CAISO mandates and initiatives are expected to significantly impact RPU.

- ✓ SB X1-2 – Renewable Portfolio Standard (RPS): SB X1-2, signed into law in 2011, which mandates that in-state electric utilities procure 33% of renewable resources to serve retail loads by 2020.

- ✓ AB 32 – California Greenhouse Gas (GHG) Reduction Mandate: AB 32, signed into law in 2006, which mandates statewide reduction of GHG emissions to 1990 levels by calendar year 2020.

- ✓ SB 1368 – Emission Performance Standard: SB 1368, signed into law in 2006, which mandates that electric utilities are prohibited to make long term financial commitments (commitments greater than 5 years in duration) for base-load generating resources that exceed GHG emissions of 1,100 lbs/MWh.

- ✓ AB 2514 -- Energy Storage: AB 2514, signed into law in 2010, which directs the governing boards of publicly-owned utilities (POUs) to consider setting targets for energy storage procurement by October 2014.

- ✓ Governor's Distributed Generation (DG) Mandate: an executive directive issued in 2012 to develop 12,000 MW of distributed generation resources within California over the next 10 years.

- ✓ FERC Order 764 – 15-Minute Market Initiative: the implementation of a CAISO 15-minute market that will schedule and financially settle all transactions through the CAISO on a 15-minute interval basis.

- ✓ CAISO Flexible Resource Adequacy and Enhanced Must Offer Obligation (FRAC/MOO): the new CAISO RA paradigm, aimed at acquiring control over significant amounts of participating member's flexible capacity that can be ramped up and down fairly quickly to assist in managing CAISO system supply and demand balance needed to integrate increasing amounts of intermittent renewable resources.

All of these current mandates and initiatives have and continue to constrain RPU's power procurement decisions and impact RPU's power supply costs, often in a detrimental manner. In Chapter 5 of this IRP we analyze these mandates and initiatives in detail and suggest potential mitigation measures for avoiding at least some of their potentially egregious future costs and impacts.

EE/DSM Programs

RPU is committed to making Riverside a greener place to live by supporting renewable energy, responsible purchasing and design, and sustainable living practices. An important portion of RPU's future resource strategy is to cost effectively expand our Energy Efficiency (EE) and Demand Side Management (DSM) programs.

In order to successfully integrate, analyze and compare EE and/or DSM programs with power supply side options, we need to be able to calculate the total program impact equation for each EE or

DSM program of interest. In Chapter 6 we begin to analyze the costs and benefits of some of RPU's more popular EE and DSM programs. Additionally, we identify the supplemental analysis work that needs to be undertaken to better quantify the comprehensive costs and benefits of each EE and DSM program that RPU currently offers. Such a comprehensive effort can only be achieved if the Power Resources Division, Public Benefits Division and Energy Delivery Division work cooperatively together to correctly identify all of the relevant generation, transmission, distribution and customer costs and benefits associated with these EE/DSM programs.

Intermediate Term Power Resource Forecasts

In Chapter 8 we present a detailed overview our most critical intermediate term (five year forward) power resource forecasts. This overview quantifies the power supply forecasts and metrics that the Planning Unit routinely analyzes, monitors and manages in order to optimize Riverside's position in the CAISO market and minimize our associated load serving costs. More specifically, these metrics include forecasted (a) capacity, system peaks and Resource Adequacy needs, (b) renewable energy resources and projected RPS percentages, (c) primary resource portfolio statistics, (d) internal generation statistics, (e) hedging percentages and open energy positions, (f) unhedged energy costs and cost-at-risk (CAR) statistics, (g) GHG emission profiles and net carbon allocation positions, and (h) five-year forward Power Resource budget estimates.

Based on the forecast data presented in Chapter 8, the following primary conclusions can be drawn concerning RPU's intermediate term resource positions.

- ✓ Although RPU will have enough generation capacity to meet our expected monthly system peaks in 2015, we cannot meet the 115% RA requirement during the Q3 summer months. Additionally, although we have contracted for new geothermal capacity in 2016 and 2019 and also extended our Hoover contract past 2017, it is currently unclear if we will be able to obtain RA credit for these resource additions and/or contract extensions. In the absence of such credit, we will not have enough capacity to fully meet our CAISO RA requirements during any Q3 summer months on/after 2016. Under our current pricing assumptions, approximately 6.9 million dollars of additional RA will need to be forward purchased to satisfy this Resource Adequacy mandate.

- ✓ Additionally, the CAISO is currently implementing a new flexible RA paradigm under its current FRAC/MOO proposal. Under this new paradigm, it is reasonable to expect that our RA costs will be at least as high as RPU's cost under the current RA paradigm, and potentially much higher due to the fact that our LM6000 RERC units may not fully qualify as Category 1 flexible RA resources. This new FRAC/MOO paradigm potentially represents RPU's single greatest financial exposure over the next three-to-five years.

- ✓ RPU is on track to procure an excess amount of renewable energy, above and beyond our minimum mandated amounts. Beginning in early 2016, RPU should exceed our minimum SB-2 25% RPS mandate by about 4%, reaching a 31% RPS in CY 2017 and then a 36% to 37% RPS in CY 2019. All of these new renewable PPAs qualify as Portfolio Content Category 1 products under the SB-2 paradigm and the above mentioned RPS percentages do not include any Category 2 bundled renewable products or Category 3 tradable renewable energy credits (TRECs).

- ✓ RPU has about 85% of its load serving needs naturally hedged through long-term PPAs and generation ownership agreements. The remaining 15% of open energy positions need to be actively hedged via forward market purchases of energy and natural gas. Most of the remaining open energy volumes are associated with June-Oct heavy load (HL) time periods (particularly Q3 HL), and with Mar-Apr outage events. RPU's current expected costs to fully close these open HL positions range from 8.9 to 13.7 million dollars annually in the 2015-2019 time period. The associated cost-at-risk (CAR) metrics for the same time period currently range from 3.9 to 8.2 million dollars, respectively.

- ✓ RPU is expected to have more than enough Carbon allowances to fully meet our direct emission compliance needs through 2020. We currently forecast an excess allowance balance of approximately 267,000 to 304,000 credits annually. These are expected to be monetized through the CARB quarterly auction process, with most of the proceeds used to help offset RPU's incremental renewable energy costs.

- ✓ RPU's FY15/16 net portfolio cost is projected to decrease by approximately 3.5 million dollars over the prior year's FY14/15 forecasts; this decrease is primarily due to the SONGS generation facility decommissioning activities. Beyond FY15/16, our overall Power Resource budget costs are currently forecasted to increase by 6 to 10 million dollars per year (through FY19/20), due to the simultaneous impact of rising CAISO transmission, energy and capacity costs.

In summary, RPU is reasonably well positioned to meet its load serving needs over the next five years while minimizing the forecasted increase in its internal portfolio costs. RPU's CAISO market costs could be further significantly impacted under the new FRAC/MOO proposal; our staff remains actively engaged in the FRAC/MOO stakeholder process to minimize these RA related cost impacts. With respect to energy needs, some additional systematic forward hedging activities are required to maintain cash flow stability. Additionally, some opportunities still exist for further renewable or thermal resource procurement, specifically during Q3 summer months.

Critical Longer Term Power Resource Issues

The bulk of the analytical work presented in this IRP has been performed to address a multitude of longer-term power resource planning issues. Chapters 9 through 13 quantify the various results for the longer term power resource analyses that we have considered.

Chapter 9 outlines RPU's longer term future capacity and renewable energy needs for the 2014-2033 time horizon. Ultimately, these needs will be primarily influenced by our future load growth rates and the termination date of our 136 MW IPP Coal contract. However, our future capacity needs will also be significantly impacted by changes to the CAISO RA paradigm and the type of RA resources that satisfy CAISO's reliability needs in the future. Likewise, our renewable energy needs will depend critically upon future RPS mandates.

- ✓ For planning purposes, our strong and weak load growth scenarios are analyzed against a "33% through 2030", "40% by 2030" and "50% by 2030" RPS mandates in Chapters 10 and 12 of this IRP, in order to gain a better idea of our potential future renewable energy needs.

- ✓ Likewise, various potential capacity shortfalls are quantified in detail in Chapters 9 through 12 of this IRP, in order to fully quantify the associated capacity replacement costs that Riverside could face over the next twenty years.

Chapter 10 examines the projected budgetary impacts of twelve different future resource scenarios. These twelve scenarios are derived from combinations of two potential future load growth patterns, two RPS mandates, and two IPP contract termination dates, along with the use of both unhedged and hedged market energy purchases to replace the expired IPP contract. Each of these scenarios is examined in detail under simulation, specifically with respect to minimizing our expected cost of service over the next twenty year time horizon.

The graph shown in Figure ES.1 shows the expected, load normalized cost of service (COS_{LN}) estimates in 2033 for these twelve resource planning scenarios. In addition to each estimate (shown as black diamonds), two standard deviations of uncertainty are also shown (green horizontal bars); these bars define the range of uncertainty associated with each COS_{LN} estimate. Note that our long term load growth projections represent the single greatest driver of our ultimate cost of service, while our hedging strategy represents the primary factor influencing the associated COS_{LN} uncertainty estimates.

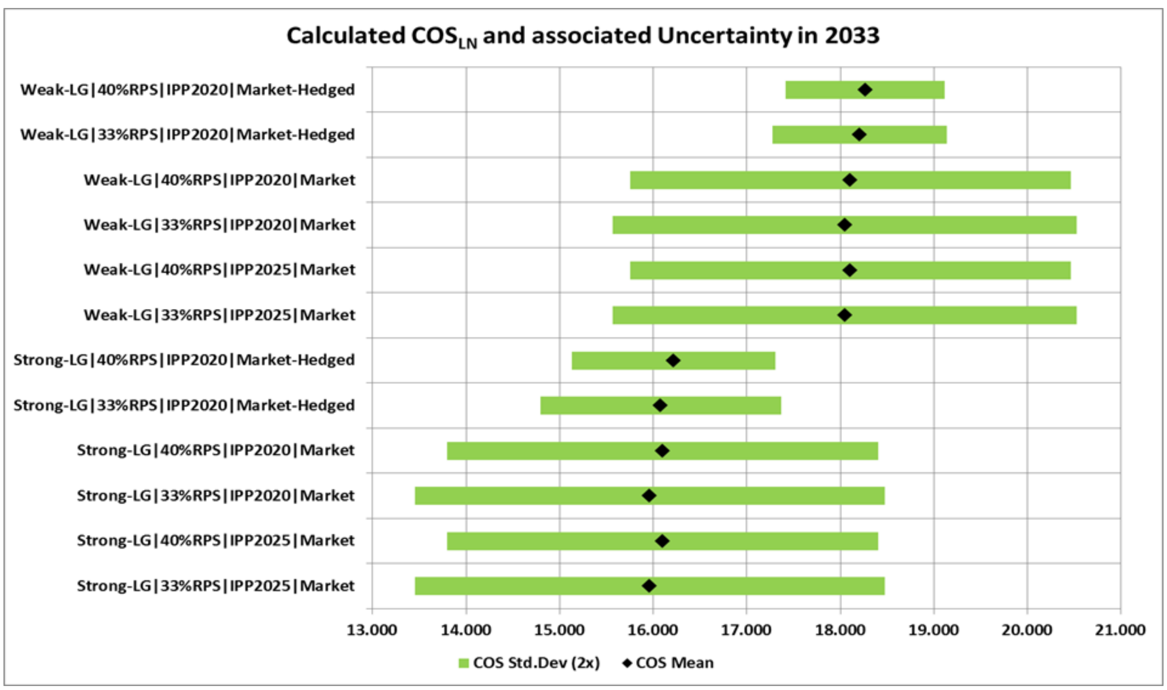


Figure ES.1. Forecasted 2033 COS_{LN} and associated uncertainty estimates (± 2 standard deviations) for the twelve planning scenarios examined in Chapter 10.

Based on the detailed simulation results, the following conclusions can be drawn with regards to our future cost of service forecasts and associated portfolio risk projections.

- ✓ First, our assumed future load growth rate materially and significantly impacts our future cost-of-service forecasts. Our COS_{LN} forecasts are 10% higher in 2028 and 13% higher in 2033 under a weak load growth assumption, as compared to the strong (healthy) assumption.

- ✓ In contrast to the load growth impact discussed above, we project that RPU can reach and maintain a 40% RPS mandate with relatively minimal rate impacts (i.e., < 1%), provided renewable energy contract prices remain near their current levels (e.g., within the $65/MWh to $80/MWh price range). Given that the "all-in" thermal energy generation costs are around $60/MWh in our current portfolio, the purchase or contracting of additional renewable energy assets currently represents one viable future procurement strategy, assuming that the corresponding energy can be effectively used to hedge our load serving needs.

- ✓ The timing of our IPP contract termination date will also significantly impact our future cost of service. We estimate that there could be a 1.6 ¢/kWh to 1.7 ¢/kWh cost increase associated with the combined effects of an early, non-voluntary IPP contract termination event <u>and</u> the end of our free Carbon allowances after 2020. (Note that 1.0 ¢/kWh to 1.1 ¢/kWh of this cost increase is associated with the loss of free Carbon emission credits.)

- ✓ From a strictly economic perspective, it does not currently make sense to try and unilaterally terminate our IPP contract any earlier than necessary. Rather, we should continue to support a market driven dispatch scheme that recognizes the inherent Carbon cost embedded in this energy asset, while planning for a replacement option that can come online just a few years before the IPP contract terminates.

- ✓ As demonstrated by the Chapter 10 market price shock analyses, some type of fixed price generation asset or long-term hedged energy contract(s) will need to be purchased after our IPP contract terminates if we wish to contain our future portfolio risk at an acceptable level. RPU should not leave a 136 MW load serving position open and exposed to significant SP15 day-ahead market price movements; the resulting cash-flow uncertainty will simply be too severe.

Five additional, alternative generation replacement scenarios that could represent reasonable IPP replacement options are next examined in Chapter 11, and then compare to the baseline, forward market hedged energy scenario examined in Chapter 10. These five alternative replacement options are as follows: (a) new internal generation: a 100 MW GE LMS-100 high-efficiency, simple cycle gas plant, (b) new internal generation: five 9.3 MW Wartsila 20V34SG simple cycle internal combustion units, stacked together into a 46.5 MW generation facility, (c) a decision to participate in and purchase 50 MW of the 1,000 MW IPP Repower Project, (d) replacing 75 MW of the IPP coal energy with a new long term renewable contract, and (e) the acquisition of a near-term 150 MW commercial tolling contract (beginning in January 2016).

Figure ES.2 shows the expected, load normalized cost of service (COS_{LN}) estimates in 2033 for both the baseline and five IPP replacement scenarios examined in Chapter 11. Once again, the estimates are shown as black diamonds, while the green bars define the range of uncertainty associated with each COS_{LN} estimate. As compared to the baseline scenario, four of the five IPP replacement scenarios result in an increased cost of service, and all five replacement scenarios result in higher associated COS_{LN} uncertainty estimates.

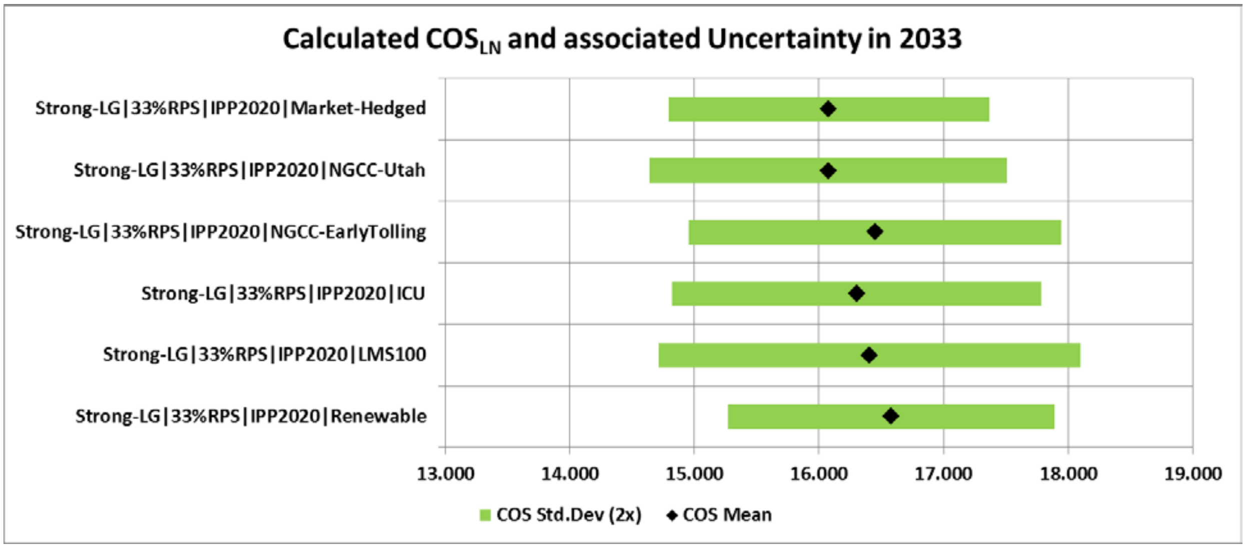


Figure ES.2. Forecasted 2033 COS_{LN} and associated uncertainty (± 2 standard deviations) for the six IPP contract replacement options examined in Chapters 10 and 11.

The results presented in Chapter 11 are preliminary and subject to further refinements and confirmation of various capital input costs. Notwithstanding these issues, some useful preliminary conclusions can be drawn from these analyses, specifically:

- ✓ With respect to a risk minimized COS_{LN} criteria, none of the generation alternatives considered in Chapter 11 outperform the baseline forward hedged, market power contracts option.

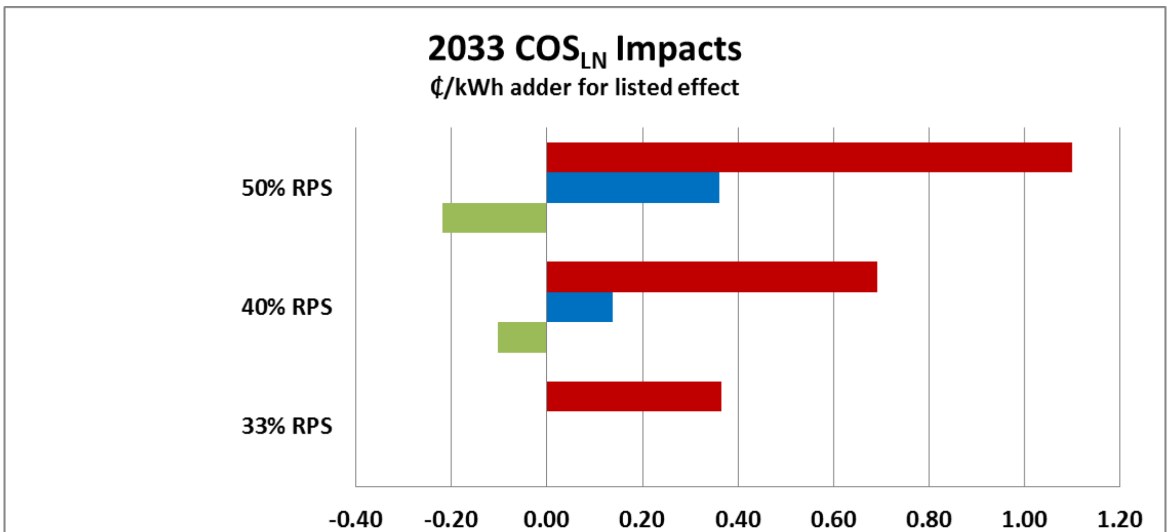
- ✓ The Repower Project scenario represents the most cost-effective alternative option analyzed in Chapter 11, although not by a wide margin. Given this result, RPU should remain engaged in the Repower Project discussions and preserve this alternative as a future option for replacing our IPP contract (assuming that these discussions continue).

- ✓ The value associated with the additional benefits that new internal generation might offer RPU need to be better understood and quantified, in order to perform a more meaningful comparison between alternatives. Additional studies will be required, given that some of these potential benefits are dependent upon the CAISO market paradigm in the future and/or the development schedule of the Riverside Transmission Reliability Project.

- ✓ It is not unreasonable to consider replacing at least some of the expiring IPP energy with base-load renewable resources, if the increased cost can be justified to and accepted by RPU's customers. However, In order to implement this alternative, competitively priced landfill gas or biomass renewable resources in the CAISO footprint would need to be identified and procured under future PPAs. The existing QFs that are expected to expire in the coming years with the IOUs may constitute the primary pool of resources in this category.

- ✓ The early tolling option does not appear to represent a viable alternative at this time, given the current (considerable) uncertainty surrounding the IPP contract end-date and the associated cost uncertainty for post-2020 Carbon allowances.

The results presented in Chapter 12 define a range of potential future rate impacts for three different RPS mandates under two renewable energy pricing assumptions. The cost impacts associated with these six scenarios are summarized in Figure ES.3 below.



	33% RPS	40% RPS	50% RPS
50% Price Increase (¢/kWh)	0.37	0.69	1.10
RPS Mandate (¢/kWh)	0.00	0.14	0.36
Risk Reduction (¢/kWh)	0.00	-0.10	-0.22

Figure ES.3. Projected annual net COS_{LN} impacts in 2033 for the three RPS mandates under the baseline and elevated renewable energy pricing assumptions.

The two key findings from these analyses are as follows:

- ✓ A 50% price increase above our current renewable energy pricing assumptions has a greater impact on the cost of service estimates, as opposed to the RPS target levels. For example, under our current pricing assumptions, our cost of service is forecasted to increase by only 0.14 ₵/kWh if we adopt a 40% RPS by 2030 target. However, if prices were to increase by 50%, then our cost of service could increase by 0.83 ₵/kWh under the same 40% RPS scenario.

- ✓ Achieving a 40% by 2030 RPS target is very achievable, provided that renewable energy prices remain stable and that RPU is very strategic about how it acquires and incorporates a greater percentage of renewable energy assets into its resource portfolio.

In addition to our IPP replacement and RPS target decisions, RPU faces a number of additional longer-term resource planning issues that deserve additional attention. In Chapter 13 we examine four of these resource planning issues in greater detail. More specifically, in Chapter 13 we examine the value of a "generic" Energy Storage system, the value of an "ideal" DSM/DR program, the cost/benefit impacts associated with customer installed solar PV systems in the RPU service area, and the potential benefits and impacts associated with electric vehicles. Some recommendations for how RPU should deal with each of these secondary issues are also presented.

Overall Summary of Findings

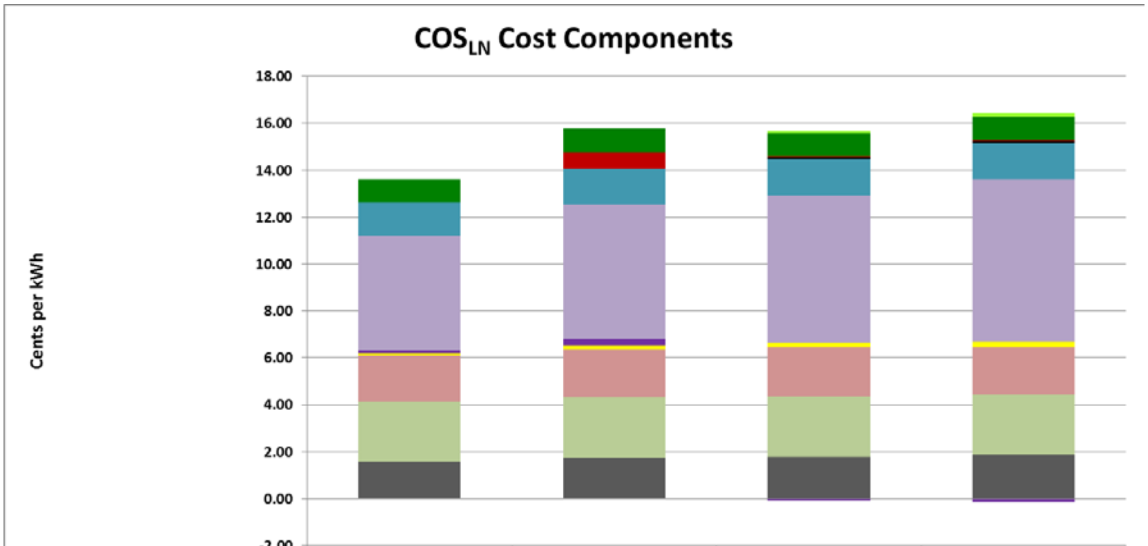
With respect to identifying a risk-integrated, least cost, optimal future resource portfolio, the three key, critical findings from the Chapter 10 through 12 studies were as follows:

1. Of all the different resource scenarios examined in Chapter 10, the forward market hedged scenarios clearly resulted in the least risk solutions. The lowest COS_{LN} metrics were associated with the strong load growth, 33% RPS, 2025 IPP end-date scenario, but also that the minimal increased cost of moving to a 40% RPS (~0.14 ₵/kWh in 2033) was partially offset by the reduced risk estimate (~0.10 ₵/kWh).

2. After examining five alternative generation scenarios in Chapter 11 that could serve as realistic IPP replacement options, we were unable to identify any alternative that produced a lower, risk-integrated COS_{LN} metric than the forward market hedging option (first examined in Chapter 10).

3. After examining our 33%, 40% and 50% RPS scenarios under two long-term pricing schemes, the primary factor influencing the COS_{LN} metric was found to be the renewable energy contract price, as opposed to the RPS level. Thus, reaching and maintaining at 40% RPS should be achievable in a cost-effective manner, provided renewable energy prices remain competitive.

Given these results, it is reasonable to propose that the strong load growth, 40% RPS, 2025 IPP end-date, forward hedged market power replacement scenario represents RPU's optimal future portfolio configuration with respect to simultaneously minimizing both our load serving costs and risks. Under such an assumption, Figure ES.4 shows a breakdown of the forecasted COS_{LN} cost components for this future portfolio configuration for the forecast years 2018, 2023, 2028 and 2033. As shown in this figure, future wholesale load purchases represent our largest cost component, followed by "all other" utility costs (primarily personnel and infrastructure), bond debt payments (for current and future capital improvements), and general fund transfer payments. Our CAISO costs (TAC and Uplift charges) and 33% RPS cost components are also forecasted to be non-negligible, as are our expected post-2020 carbon costs (at least until our IPP contract ends).



	2018	2023	2028	2033
Incremental Renewable Cost 40% RPS	0.00	0.00	0.08	0.15
Renewable Cost 33% RPS	0.99	1.03	0.99	0.98
Carbon Cost	0.00	0.69	0.04	0.05
Market Hedge Cost (IPP Replacement)	0.00	0.00	0.11	0.10
CAISO Costs (TAC & Other Uplift)	1.43	1.51	1.51	1.53
Portfolio Costs (Load)	4.88	5.72	6.30	6.93
Portfolio Costs (Thermal Gen & Misc)	0.12	0.30	-0.10	-0.15
RA Cost	0.09	0.17	0.20	0.24
Bond Debt (Capital Improvements)	1.96	2.03	2.09	2.02
Personnel & All Other Utility Costs	2.58	2.58	2.57	2.56
GFT	1.57	1.73	1.79	1.87

Figure ES.4. Forecasted COS$_{LN}$ cost components for RPU's optimal future portfolio configuration.

In summary, a significant number of diverse resource planning issues are discussed and analyzed in this 2014 Integrated Resource Plan. A much more detailed discussion of our findings is presented in Chapter 14, along with our recommendations for further analyses and studies that should be undertaken. In this concluding chapter, we also suggest some strategies that RPU can implement now in order to continue to provide the highest quality water and electric services at the lowest possible rates to benefit the Riverside community. The analyses, findings and recommendations presented in this 2014 Integrated Resource Plan are designed to assist Riverside Public Utilities to continue to achieve this goal in a proactive, intelligent, and optimal manner.

1. Introduction

1.1 The Purpose of Riverside's Integrated Resource Plan

This *2014 Power Supply Integrated Resource Plan* ("IRP") provides an impact analysis of, as well as the types and timing related to, Riverside's acquisition of new power resources, and the effect these resources will have on Riverside Public Utilities future projected cost of service. Both current and proposed Supply Side and Demand Side resources are examined in detail, towards a goal of continuing to provide the highest quality electric services at the lowest possible rates to benefit our local community, and subject to Riverside's procurement decisions meeting a diverse set of state and regional legislative / regulatory mandates.

In the most general sense, an IRP can be seen as a process of planning to acquire and deliver electrical services in a manner that meets multiple objectives for resource use. However, the focus of an IRP can vary considerably, depending upon each utilities specific situation. In this 2014 IRP we review and analyze both intermediate term (5-year forward) and longer term (20-year forward) resource portfolio and energy market issues. The goals of this IRP are multi-fold, but can be broadly summarized as follows:

- To provide an overview of Riversides (a) energy and peak demand forecasts, (b) current generation and transmission resources, and (c) existing electric system.

- To review and assess the impact of important legislative and regulatory mandates imposed by various state or regional agencies (California Energy Commission, California Air Resources Board, South Coast Air Quality Management District, etc.), along with the impact of important active or proposed California Independent System Operator (CAISO) stakeholder initiatives.

- To summarize and assess our current set of Energy Efficiency (EE) and Demand Side Management (DSM) programs, and examine if and how these EE/DSM programs can be further expanded to help offset some of Riversides Supply Side needs.

- To quantify our expectations and uncertainty around our intermediate term power resource forecasts, specifically with respect to meeting our (a) projected capacity and resource adequacy needs, (b) renewable portfolio standard (RPS) mandates, (c) carbon emission goals and mandates, (d) power resource budgetary objectives, and (e) cash-flow risk metrics.

- To examine and analyze certain critical longer term power resource issues, specifically with respect to how these issues are forecasted to impact our future cost-of-service. The primary longer term issues examined in this IRP include (a) projected load growth impacts, (b) timing impacts associated with the termination of our Intermountain Power Project (IPP) contract, (c) how market price shocks impact our resource portfolio (i.e., portfolio sensitivity analyses), (d) potential replacement options for our IPP contract, and (e) potential changes in future RPS mandates.

1.2 Resource Planning: Guiding Principles and Current Strategies

RPU's resource portfolio has evolved over time to address key issues such as CAISO market price volatility, various fuel and delivery risk tolerances, internal generation and distribution needs, and load and peak demand growth. Price stability, cost effectiveness, and technology diversification have represented the traditional guiding principles used by RPU when selecting generation assets or contracts. Consistent with the generation technologies of the 1980s and 1990s, RPU had historically relied upon coal and nuclear assets for much of its base-load energy needs, along with various energy exchange contracts and forward market purchases to meet its summer peaking needs. After the 2000-2001 California Energy Crisis, RPU embarked upon developing more natural gas power plants within its distribution system in order to better meet our local reliability requirements and summer peaking needs in an economical and reliable manner.

Additionally, over the last fifteen years, RPU's portfolio of generation assets has continued to evolve to meet new regulatory mandates, particularly the need to achieve specific greenhouse gas (GHG) reduction targets and a commitment to incorporate an increasing percentage of renewable resources. We entered into our first significant contracts for renewable energy in 2002 and 2003, met our 20% RPS goal in 2010, and are on track to significantly exceed the 33% RPS by 2020 mandate. It is worth noting that over the last five years, all of our new portfolio resource additions have been exclusively renewable assets; i.e., wind, solar, and geothermal contracts.

To the extent possible, RPU assesses and applies a set of high-level guiding principles when examining the feasibility of adding a new generation asset or contract to its existing portfolio of resources. While no single contract or asset can ever be expected to represent an optimal choice with respect to all of these principles, the best contracts or assets ensure that most of these principles are satisfied. These guiding principles can best be expressed in the form of the following questions: "Does the new asset or contract…"

- Ensure wholesale and/or retail price stability?
- Maintain or improve the technology diversification within our existing portfolio?
- Support or improve our local and/or system reliability needs?
- Meet our cost effectiveness criteria?
- Properly align with RPU's daily and/or seasonal load serving needs?
- Reduce our Carbon footprint and/or increase our renewable energy supply?
- Support our commitment to environmental stewardship?

Table 1.2.1 presents more detailed justifications and rational for each guiding principle.

At this current point in time, Riverside Public Utility (RPU) is somewhat uniquely positioned with respect to its power resource portfolio. For the last five years RPU has embraced an active plan to significantly increase the percentage of renewable energy resources in its resource portfolio, and within the last three years RPU has signed power purchase agreements (PPA's) for seven new or existing renewable energy projects. Due to these purchases, RPU is on track to serve almost 37% or its retail electrical load with renewable energy by 2019. Additionally, these purchases have left RPU almost "fully" resourced, at least for the intermediate term. Thus, at least for the next five years, the Power Resources Division primary focus will be on monitoring, incorporating and managing these new renewable energy resources, along with optimally positioning RPU within the broader CAISO market.

Table 1.2.1 Detailed justification and rational for each guiding principle (for assessing the feasibility and desirability of new assets or contracts).

Guiding Principle	Justification / Rationale
Price Stability	At the most fundamental level, RPU procures assets or contracts to ensure energy price stability; i.e., to meet our load serving needs with a high degree of price certainty. Optimal assets/contracts will offer either a fixed price structure, or a price structure that can be effectively forward hedged.
Technology Diversification	A portfolio that relies too much on a single type of generation technology or fuel source is more vulnerable to catastrophic technology or fuel disruptions. In contract, portfolios that contain a wide variety of technology and fuel sources are much more robust to such disruptions.
Local/System Reliability	As a Load Serving Entity (LSE), RPU must ensure that it can effectively meet its system peaking needs under all reasonable conditions. Assets or contracts that provide either system or local capacity attributes help PRU effectively meet these needs.
Cost Effectiveness	The development or contract cost for different technologies can vary significantly over time. However, at any point in time it is typically possible to evaluate the cost effectiveness of a particular asset, and/or perform cost comparisons and generation revenue studies, etc., to determine the overall competitiveness of a specific offer. Obviously, assets or contracts that are the most cost effective are preferable.
Energy Alignment	Again, as an LSE, RPUs fundamental goal is to reliably and cost effectively meet its load serving needs at all times of the day, every day of the year. Thus, assets or contracts that can provide more fixed-price power to our distribution system when our load serving needs are greatest help RPU met this goal.
Carbon Footprint	As California moves forward with its AB32 GHG reduction mandates, it is becoming increasingly important to procure assets and/or contracts with minimal Carbon footprints. (Note: these GHG reduction mandates essentially determine and direct California RPS goals.)
Environmental Stewardship	Every asset has some degree of environmental impact, no matter what its technology base. Whenever possible, RPU should demonstrate good environmental stewardship by procuring assets and contracts with minimal environmental impacts, and/or by supporting local, state, and federal policies and regulations that support the cost effective development of such assets and contracts.

Longer term, RPU faces some very important power supply decisions. The most critical of these concerns the Intermountain Power Project, specifically what resource (or resources) RPU will procure to replace this coal contract when it expires. Technically, this contract does not expire until May 2027. However, the Los Angeles Department of Water and Power (LADWP) manages the scheduling of all IPP energy for the California participants, and LADWP has announced their intention to retire these Utah coal plants no later than January 1, 2026. Additionally, this contract could be terminated earlier (perhaps as early as 2021), should the US Environmental Protection Agency require the installation of significant additional emission control systems on the plants.

As such, it is both prudent and advantageous to begin performing serious cost/benefit studies of at least some potential IPP replacement options, and examine these options within this broader IRP. However, the replacement of our IPP contract is still seven to twelve off into the future. Hence, our ability to fully quantify the potential cost-of-service impacts for various replacement options is currently somewhat limited, and the impact studies presented here only begin to frame and quantify RPU's various replacement options.

Perhaps most importantly, it should be emphasized that RPU is a pro-active participant in the CAISO MRTU wholesale energy market. The wholesale power markets in California are currently undergoing unprecedented change, and many of these paradigm shifts have the potential to significantly alter the assumptions underlying this IRP. Hence, although this and future Integrated Resource Plans are intended to form the basis for formulating and executing supply-side and demand-side strategies, Power Resources Division staff must retain the flexibility to quickly adapt to changing market conditions and paradigms as circumstances develop. Therefore, this IRP should be viewed as a dynamic roadmap to help guide our potential future long term decision making process, rather than as an absolute set of static procurement recommendations.

1.3 Document Organization

The entirety of this IRP document contains fourteen (14) Chapters and six (6) Appendices. The chapter organization and layout sequentially follows the general goals discussed above; i.e., background information (Chapters 2-4), mandates and initiatives (Chapter 5), EE and DSM programs (Chapter 6), forward market views and intermediate term portfolio forecasts (Chapters 7-8), and longer term resource planning issues (Chapters 9-13). Additionally, Chapter 7 and Appendix A describe the production cost modeling software used to facilitate these IRP analyses, while Chapter 14 presents an overall summary of our pertinent findings. The remaining Appendices describe secondary technical details associated with specific chapter analyses, respectively.

Brief descriptions of each subsequent Chapter and Appendix contained in this IRP document are presented below.

Chapter 2. RPU Energy and Peak Demand Forecasts

Chapter 2 provides an overview of RPU's long-term energy and peak demand forecasting methodology. This overview includes a discussion of our econometric forecasting approach, key input variables and assumptions, and pertinent model statistics, along with our high and low 2014-2033 output energy and peak demand forecasts.

Chapter 3. RPU Generation and Transmission Resources

Chapter 3 provides an overview of RPU's long term resource portfolio assets, including our existing resources, future renewable resources (currently under contract), and recently expired contracts. Chapter 3 also describes our transmission resources, and our transmission control agreements with the CAISO.

Chapter 4. RPU Existing Electric System

Chapter 4 briefly reviews RPU's existing electric system and describes how it operates. RPU is a vertically integrated utility that operates electric generation, sub transmission, and distribution facilities; receiving most of its system power through the regional bulk transmission system owned by SCE and operated by the CAISO.

Chapter 5. Important Legislative / Regulatory Mandates and CAISO Initiatives

Chapter 5 outlines the relevant legislative, regulatory and stakeholder issues that will have significant impact to the California electric energy industry in the foreseeable future; specifically to the markets run by the CAISO. An assessment of each issue's current and potential future impact on RPU is also provided.

Chapter 6. Energy Efficiency and Demand Side Management Programs

RPU is committed to making Riverside a greener place to live by supporting renewable energy, multiple EE and DSM programs, and sustainable living practices. Chapter 6 describes our current set of EE and DSM programs in detail, reviews our reported EE/DSM energy saving targets and goals, provides some preliminary cost/benefit analyses of three of our more popular programs, and discusses how various EE and DSM programs can be better integrated into Supply Side resource plans.

Chapter 7. Market Fundamentals

Chapter 7 presents an overview of the forward market data used by the Ascend Portfolio Modeling software platform. RPU obtains forward curve information for the Southern California electricity and natural gas markets from the Intercontinental Exchange (ICE); this forward ICE data has been used in conjunction with long term, fundamental market equilibrium constraints to calibrate all of the forward curve simulations for our IRP.

Chapter 8. Intermediate Term (Five-Year Forward) Power Resource Forecasts

Chapter 8 presents a detailed overview of our most critical intermediate term power resource forecasts. These represent power supply forecasts and metrics that the Planning Unit routinely analyzes, monitors and manages in order to optimize Riverside's position in the CAISO market and minimize our associated load serving costs. These metrics include forecasted (a) capacity, system peaks and Resource Adequacy needs, (b) renewable energy resources and projected renewable energy percentages, (c) primary resource portfolio statistics, (d) internal generation statistics, (e) hedging percentages and open energy positions, (f) unhedged energy costs and cost-at-risk (CAR) statistics, (g) GHG emission profiles and net carbon allocation positions, and (h) five-year forward Power Resource budget estimates.

Chapter 9. Long Term Forecasts: Future Capacity and Renewable Energy Needs

Chapter 9 outlines RPU's longer term future capacity and renewable energy needs for the 2014-2033 time horizon. Ultimately, these needs will be primarily influenced by our future load growth rates and the termination date of our 136 MW IPP Coal contract. However, our future capacity needs will also be significantly impacted by changes to the CAISO RA paradigm and the type of RA resources that satisfy CAISO's reliability needs in the future. Likewise, our renewable energy needs will depend critically upon future RPS mandates. Chapter 9 examines and quantifies each of these various scenarios in greater detail, and defines the scenario framework for the various IRP studies examined in Chapters 10, 11 and 12.

Chapter 10. Long Term (Twenty-Year Forward) Portfolio Analyses

Chapter 10 examines the projected budgetary impacts of twelve different future resource scenarios that describe and quantify a range of combinations for two potential future load growth patterns, RPS mandates, IPP contract termination dates, and post-IPP market energy replacement options. This budgetary assessment considers both the expected values and simulated standard deviations of our fully loaded, forecasted cost of service. The impacts of each fundamental IRP input assumption are examined in detail, specifically with respect to minimizing our expected cost of service over the next twenty year time horizon.

Chapter 11. Alternative Portfolio Analysis: Part I – Additional IPP Replacement Options

In Chapter 11 we examine five additional generation scenarios that could represent reasonable IPP replacement options, and compare these new scenarios to the forward market hedged energy scenario examined in Chapter 10. The five alternative replacement options examined in Chapter 11 are (a) new internal generation: a 100 MW GE LMS-100 high-efficiency, simple cycle gas plant, (b) new internal generation: five 9.3 MW Wartsila 20V34SG simple cycle internal combustion units, stacked together into a 46.5 MW generation facility, (c) a decision to participate in and purchase 50 MW of the 1,000 MW IPP Repower Project, (d) replacing 75 MW of the IPP coal energy with a new long term renewable contract, and (e) the acquisition of a near-term 150 MW commercial tolling contract (beginning in January 2016). Each of these alternatives is examined in detail with respect to their impact on our expected cost of service over the next twenty year time horizon.

Chapter 12: Alternative Portfolio Analysis: Part II – A Higher RPS Mandate

In addition to our IPP replacement decision, RPU faces the possibility that CA may elect to increase the 33% RPS mandate after 2020. Likewise, RPU may voluntarily decide to pursue a higher internal RPS mandate, in order to reduce our carbon footprint and reliance on fossil fuel resources. Recall that in Chapter 10 we examine and quantify the costs of reaching and maintaining both a 33% and 40% RPS through 2033 under our current renewable pricing assumptions. In Chapter 12 we expand on these analyses by examining the projected additional portfolio cost impacts associated with RPU adopting a "50% by 2030" RPS mandate. Additionally, we also reexamine the 33%, 40% and 50% mandates under significantly higher pricing assumptions (i.e., current pricing forecasts inflated by 50%), with the goal of quantifying how incremental changes in both the projected price curves and RPS percentages impact our cost of service metric.

Chapter 13. Important Secondary Resource Planning Issues

In addition to our IPP replacement decision, RPU faces a number of additional longer-term resource planning issues that deserve special attention. In Chapter 13 we examine four of these resource planning issues in greater detail: (a) the current value of Energy Storage as a resource asset, (b) the value of an "ideal" DSM/DR program, (c) the cost/benefit impacts associated with customer installed solar PV systems in the RPU service area, and (d) the potential impacts and benefits associated with electric vehicles. Some recommendations for how RPU should deal with each of secondary issues are also presented.

Chapter 14. Summary and Conclusions

Chapter 14 reviews and summarizes the various findings associated with this integrated resource planning activity. Recommendations concerning additional studies and further investigations are also presented in this concluding chapter.

Appendix A.

Appendix A presents a detailed description of the Ascend PowerSimm software package, which represents the production cost modeling software used to perform the vast majority of analyses presented in this IRP . The Ascend software platform can be used to value portfolios consisting of structured transactions, generation assets, load obligations, and hedges plus operating components of transmission, ancillary services, and conservation programs. The PowerSimm software is hierarchical and enables generation assets and market instruments to be valued individually or jointly as an element of the parent portfolio. The valuation of a utility portfolio or structured transaction follows from the application of analytic algorithms that optimize asset values and calculate hedge, load, and structured transaction values relative to an underlying simulated market.

Appendix B.

Appendix B presents some technical and statistical details concerning the estimation of our energy and peak demand forecasting models.

Appendix C.

This appendix provides the derivation of (and justification for) the 1.9 CAR multiplication factor.

Appendix D.

The full 5-Year Power Resource budget template can be found in Appendix D.

Appendix E.

Details concerning RPU's long-term debt-service assumptions are presented in Appendix E.

Appendix F.

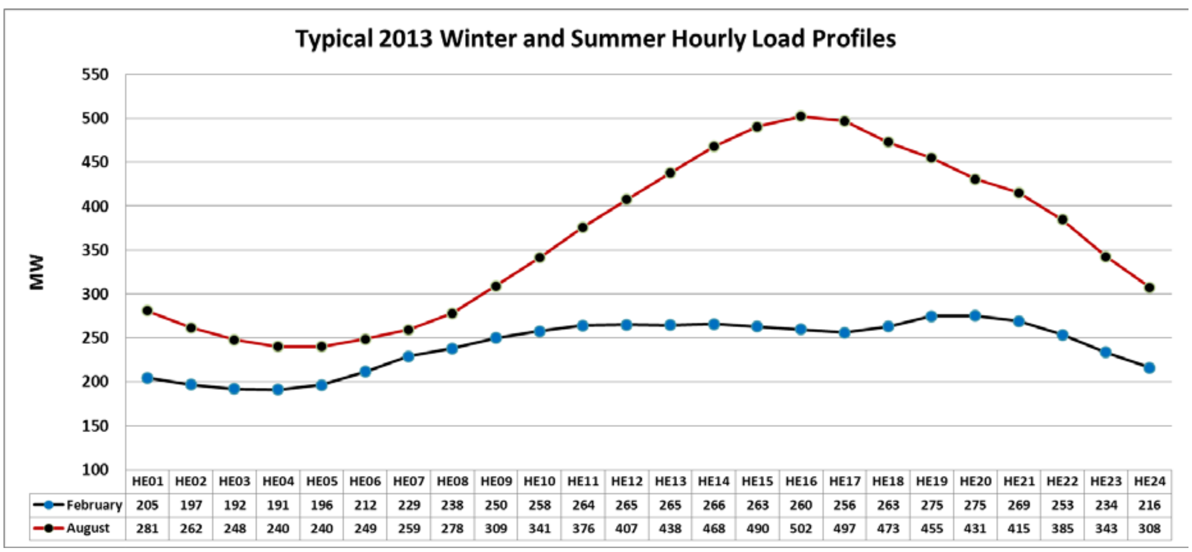
An expanded description of the forward price curve assumptions for Utah natural gas can be found in Appendix F, including the justification for the assumed $0.50 basis differential.

2. RPU Energy & Peak Demand Forecasts

This chapter provides an overview of RPU's long-term energy and peak demand forecasting methodology. This overview includes a discussion of our econometric forecasting approach, key input variables and assumptions, and pertinent model statistics, along with our 2014-2033 output energy and peak demand forecasts.

2.1 RPU Load Profiles

As of June 2013, RPU provided electrical service to approximately 107,500 metered customers across the City of Riverside, CA. Riverside represents a typical city in the Inland region of Southern California, in that we experience fairly warm summers and temperate winters. As such, our loads and peaking needs are considerably higher in the summer months and much of RPU's long term planning activities revolve around meeting our summer load and peaking needs. Figure 2.1.1 below shows our hourly load profiles for typical weekdays in February and August 2013, respectively. In August we expect to need about 50% more energy and 80% more capacity to meet our load serving requirements, as compared to February.



	HE01	HE02	HE03	HE04	HE05	HE06	HE07	HE08	HE09	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
February	205	197	192	191	196	212	229	238	250	258	264	265	265	266	263	260	256	263	275	275	269	253	234	216
August	281	262	248	240	240	249	259	278	309	341	376	407	438	468	490	502	497	473	455	431	415	385	343	308

Figure 2.1.1. Hourly system load profiles for typical 2013 weekdays in February and August.

RPU's customer base represents a diversified mix of Residential, Commercial and Industrial customers. Nearly all Residential customers are currently billed under a tiered-rate system. More than 90% of our Commercial customers are billed on a flat-rate; the remaining medium-sized Commercial customers are billed under a commercial demand rate. Nearly all of our Industrial customers are billed under either a contract or a time-of-use (TOU) rate. As of June 2013, RPU served approximately 96,200 Residential, 10,400 small and medium-sized Commercial and 900 Industrial customers, respectively.

Notwithstanding the fact that nearly 90% of RPU's customers represent residential households, the total energy consumption by customer class is much more evenly distributed. Figure 2.1.2 shows how our 2012 retail sales distributed across customer classes; it is worthwhile to note that our 900 Industrial customers accounted for 46% of our total retail sales. Our Residential customers accounted for exactly one-third of our sales (33.3%), while our Commercial customers accounted for another 19.2%. Miscellaneous (Other) accounts accounted for the remaining 1.5% of our 2012 retail sales. Finally, as shown in figure 2.1.2, our summer peaking needs are driven primarily by the summer AC (cooling) needs of our three customer classes, particularly our Residential customer class.

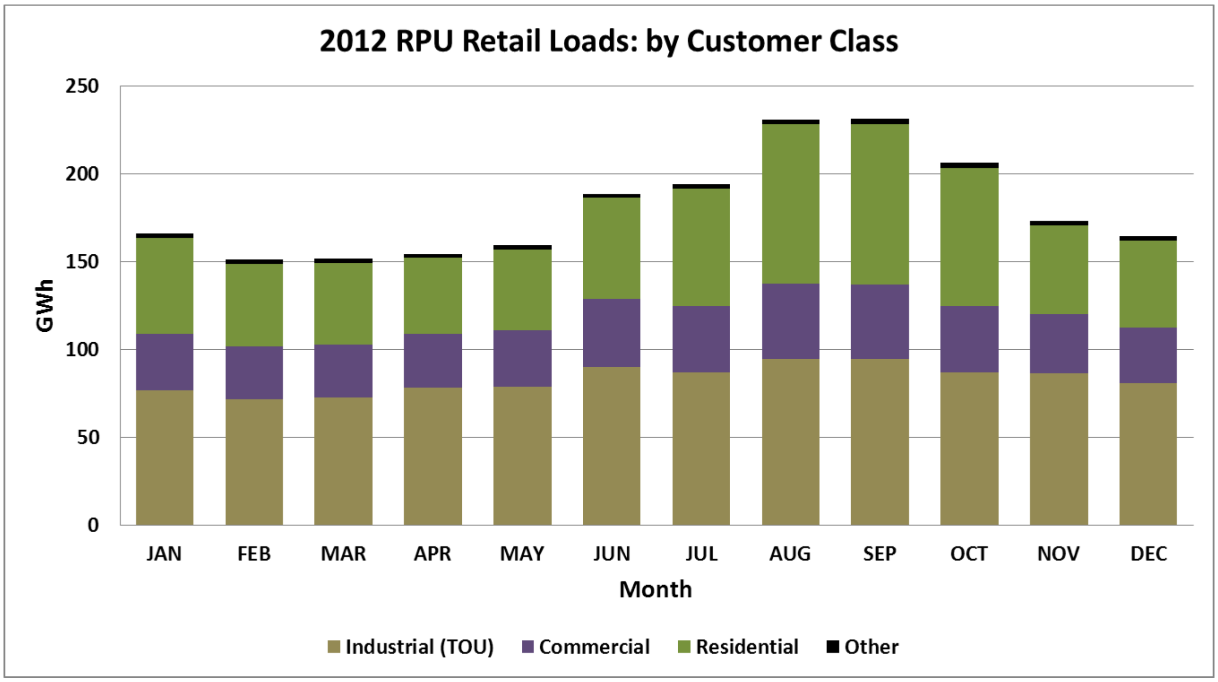


Figure 2.1.2. 2012 RPU retail sales by month and customer class.

2.2 Forecasting Approach

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 Residential, Commercial and Industrial customer classes. These models are calibrated to historical load and/or sales data extending back to January 2003. The input variables to these econometric models include various monthly weather summary statistics, specific calendar effects, and two econometric input variables for the Riverside – San Bernardino – Ontario metropolitan service area: annual per capita personal income (PCPI) and monthly non-farm employment (EMP) estimates. The monthly forecasts produced by these models are used to project RPU system demand and peak loads and retail sales ten to twenty years forward in time.

The Planning unit updates our forecasting equations once a year, typically in early spring (February-March time frame). However, the March 2013 analysis showed that the monthly system load and peak forecasting equations developed in February 2012 were still reliable and accurate; hence these 2012 equations were used to produce the 2014-2033 monthly forecast data examined in this IRP. Note that these monthly forecasts are in turn used to calibrate our Ascend hourly system load model. This latter model is incorporated into the Ascend PowerSimm software platform and used to either forecast and/or simulate hourly RPU system loads, based on either forecasted or simulated daily temperature inputs (minimum and maximum daily temperatures for the Riverside area, respectively), and prospective monthly load and peak forecasts. Note that our historical daily temperature data have also been summarized into monthly cumulative cooling and heating degree indices. These indices are in turn used as prospective weather input values for our monthly load forecasting equations.

All monthly forecasting equations are statistically developed and calibrated to approximately ten years of historical monthly energy data, while the hourly system load model is calibrated to four years of hourly load observations. Note that the hourly model currently produces system forecasts only; hourly forecasts for each customer class are not currently produced due to the lack of metered hourly customer class load information. Additionally, this section only summarizes the methodology and statistical results pertaining to our monthly forecasting equations; details concerning the hourly model are presented elsewhere (Level II Technical Documentation for PowerSimm, Ascend Analytics, 2012).

2.3 Input Variables

The various weather, economic and structural input variables used in our monthly forecasting equations are defined in Table 2.3.1. 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

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

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

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. Additionally, low order Fourier frequencies are 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

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

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

where *m* represents the numerical month number (i.e., 1 = Jan, 2 = Feb, .., 12 = Dec). Note that low order Fourier frequencies are also used to describe seasonal variation in the residual variance component of our system (wholesale) total and peak load equations.

Table 2.3.1. Weather, economic and structural input variables used in RPU monthly forecasting equations (SL = system load, SP = system peak).

Effect	Variable	Definintion	Forecasting Eqns.	
			SL	SP
Economic	PCPI	Per Capita Personal Income ($1000)	X	X
	EMP	Non-farm Employment (100,000)	X	X
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)		
Weather	SumCD	Sum of monthly CD's	X	X
	SumXHD	Sum of monthly XHD's	X	
	MaxCD3	Maximum concurrent 3-day CD sum in month		X
	MaxHD	Maximum single XHD value in month		X
Fourier terms	Fs(1)	Fourier frequency (Sine: 12 month phase)	X	X
	Fc(1)	Fourier frequency (Cosine: 12 month phase)	X	X
	Fs(2)	Fourier frequency (Sine: 6 month phase)	X	X
	Fc(2)	Fourier frequency (Cosine: 6 month phase)	X	X
	Fs(3)	Fourier frequency (Sine: 4 month phase)		X
	Fc(3)	Fourier frequency (Cosine: 4 month phase)		X

2.4 Historical and Forecasted Inputs: Economic and Weather Effects

The annual values of our 2010-2033 economic indices are shown in Table 2.4.1. Historical annual PCPI data have been obtained from the US Bureau of Economic Analysis (http://www.bea.gov), while historical monthly employment statistics have been obtained from the CA Department of Finance (http://www.labormarketinfo.edd.ca.gov). As previously stated, both sets of data correspond to the Riverside-Ontario-San Bernardino metropolitan service area.

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 have been derived from a detailed analysis of ten years of CIMIS weather data; these forecasted monthly indices are shown in Table 2.4.2. Note that these average monthly values are used as weather inputs for all 2014-2033 forecasts.

Table 2.4.1. 2010-2033 annual values for PCPI and EMP economic indices.

Year	PCPI	Inflator	EMP	Inflator
2010	29.569	-	1515.000	-
2011	29.569	0.000	1522.575	0.005
2012	29.865	0.010	1533.233	0.007
2013	30.313	0.015	1547.032	0.009
2014	30.919	0.020	1564.049	0.011
2015	31.846	0.030	1584.382	0.013
2016	32.802	0.030	1608.148	0.015
2017	33.786	0.030	1632.270	0.015
2018	34.800	0.030	1656.754	0.015
2019	35.843	0.030	1681.605	0.015
2020	36.919	0.030	1706.830	0.015
2021	38.026	0.030	1732.432	0.015
2022	39.167	0.030	1758.418	0.015
2023	40.342	0.030	1784.795	0.015
2024	41.552	0.030	1811.567	0.015
2025	42.799	0.030	1838.740	0.015
2026	44.083	0.030	1866.321	0.015
2027	45.405	0.030	1894.316	0.015
2028	46.768	0.030	1922.731	0.015
2029	48.171	0.030	1951.572	0.015
2030	49.616	0.030	1980.845	0.015
2031	51.104	0.030	2010.558	0.015
2032	52.637	0.030	2040.716	0.015
2033	54.217	0.030	2071.327	0.015

Table 2.4.2. Expected average values (forecast values) for 2014-2033 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

2.5 Monthly System Load Model

The regression component of our monthly total system load forecasting model is a function of our two economic drivers (PCPI and EMP), two calendar effects that quantify the number of weekdays (SumMF) and weekend days (SumSS) in the month, two weather effects that quantify the total monthly cooling and extended heating degrees (SumCD and SumXHD), and four low order Fourier frequencies (Fs(1), Fc(1), Fs(2) and Fc(2)). The statistical details associated with this forecasting model are presented in Appendix B. Table 2.5.1 shows the pertinent model fitting and summary statistics for our total system load forecasting equation. The equation explains approximately 99% of the observed variability associated with the monthly 2003-2011 system loads, and all input parameter estimates are statistically significant below the 0.01 significance level.

The estimates for the seasonal variance components are shown at the bottom of Table 2.5.1. These components define how the model mean square error (MSE) changes across the calendar months. An analysis of the variance adjusted model residuals suggests that these errors are also Normally distributed, devoid of outliers and temporally uncorrelated; implying that our modeling assumptions are likewise reasonable.

The regression parameter estimates shown in the middle of Table 2.5.1 indicate that monthly system load increases as either/both weather indices increase (SumCD and SumXHD); note that an increase in one cooling degree raises the forecasted load four times as quickly as a one heating degree increase. Additionally, weekdays contribute slightly more to the monthly system load, as opposed to Saturdays and Sundays (i.e., the SumMF estimate is greater than the SumSS estimate). Finally, RPU system load is expected to increase as either the area wide PCPI and/or employment indices improve over time (i.e., both economic parameter estimates are greater than 0).

Figure 2.5.1 shows the observed (blue points) versus calibrated (green line) system loads for the 2004-2011 timeframe. Nearly all of the calibrations fall within the calculated 95% confidence envelope (thin black lines) and the observed versus calibrated load correlation exceeds 0.995. Figure 2.5.2 shows the forecasted monthly system loads for 2014 through 2023 (the first ten years of our twenty year forecast), along with the corresponding 95% forecasting envelope. This forecasting envelope encompasses both model and weather uncertainty, while treating the projected economic indices as fixed inputs. Note that there is considerable uncertainty associated with summer forecasts due to the increased uncertainty surrounding summer weather patterns.

Table 2.5.2 shows the forecasted monthly RPU system loads for 2014, along with their forecasted standard deviations. Once again, these standard deviations quantify both model and weather uncertainty. The 2014 forecasts project that our annual system load should be 2,313.1 GWh, assuming that the RPU service area experiences typical weather conditions throughout the year.

Table 2.5.1. Model summary statistics for the monthly total system load forecasting equation.

Gross Monthly Demand Model (Jan 2003 - Sept 2011): GWh units
Forecasting Model: includes Weather & Economic Covariates (w/Fourier Effects)

Dependent Variable: GWhload Load (GWh)

Number of Observations Read	408
Number of Observations Used	105
Number of Observations with Missing Values	303

Weight: ht_1 (structured seasonal pattern)

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	10	74178	7417.84754	811.33	<.0001
Error	94	859.42504	9.14282		
Corrected Total	104	75038			

Root MSE	3.02371	R-Square	0.9885
Dependent Mean	170.72617	Adj R-Sq	0.9873
Coeff Var	1.77109		

Parameter Estimates

Regression Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variance Inflation
Intercept	Intercept	1	-149.11524	12.08573	-12.34	<.0001	0
PCPI	PCPI ($1,000)	1	2.99745	0.22027	13.61	<.0001	1.39787
Emp_CC	Labor (100,000)	1	3.78635	0.49617	7.63	<.0001	1.39314
sumMF	# Mon-Fri	1	5.52385	0.34037	16.23	<.0001	1.52376
sumSS	# Sat-Sun	1	4.93892	0.41948	11.77	<.0001	1.41986
sumCD	Sum CD's	1	0.16940	0.00733	23.12	<.0001	8.25305
sumHD	Sum XHD's	1	0.04716	0.01135	4.15	<.0001	2.88153
Fs1	Fs(1)	1	-4.52967	0.80873	-5.60	<.0001	3.74366
Fc1	Fc(1)	1	-7.22947	1.10550	-6.54	<.0001	7.03532
Fs2	Fs(2)	1	2.29214	0.66905	3.43	0.0009	2.79596
Fc2	Fc(2)	1	2.28435	0.47897	4.77	<.0001	1.44241

Variance Effect	Label	DF	Parameter Estimate	Standard Error
Fs1	Fs(1)	1	-0.3923	0.2867
Fc1	Fc(1)	1	-0.4679	0.2393

Durbin-Watson D	1.763
Number of Observations	105
1st Order Autocorrelation	0.087

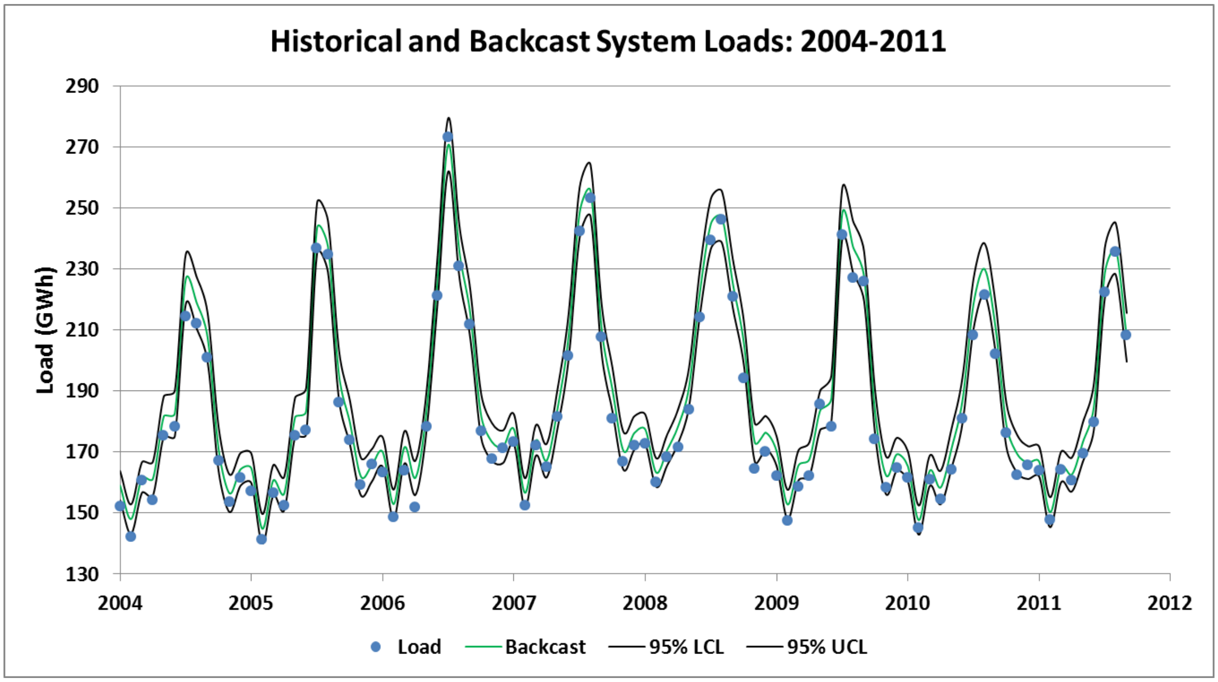


Figure 2.5.1. Observed and predicted total system load data (2004-2011), after adjusting for known weather conditions.

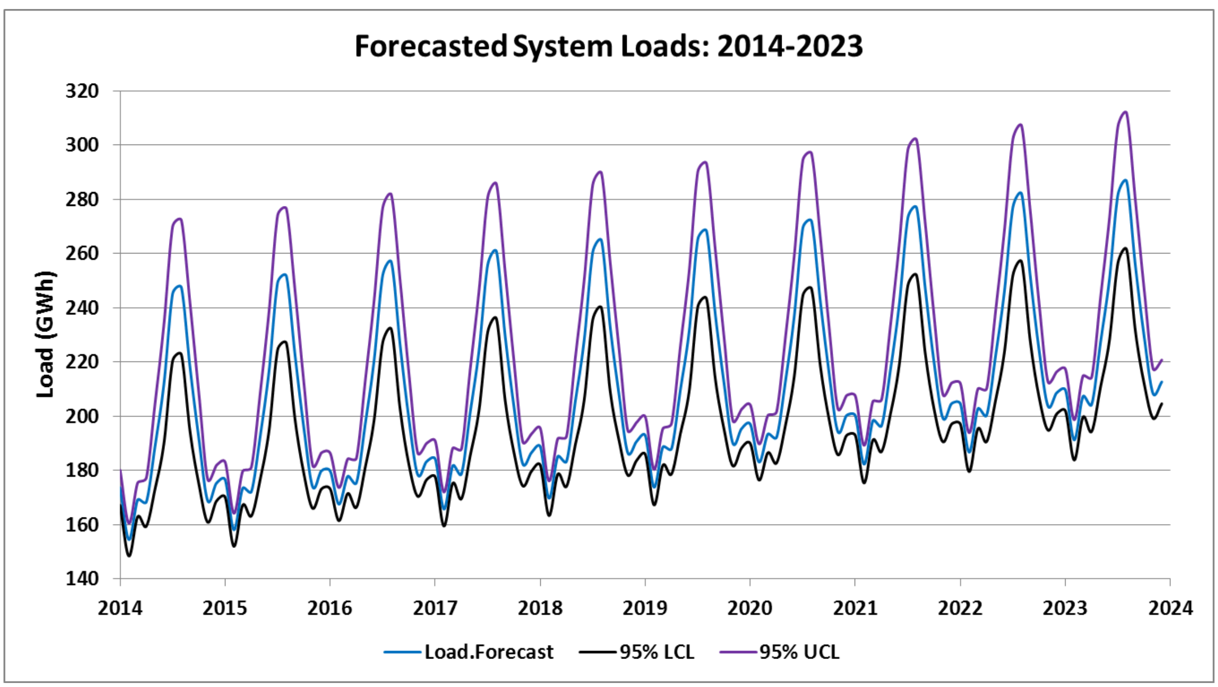


Figure 2.5.2. Forecasted monthly total system loads for 2014-2023; 95% forecasting envelopes encompass both model and weather uncertainty.

Table 2.5.2. 2014 monthly total system load forecasts for RPU; forecast standard deviations include both model and weather uncertainty.

Month	Load (GWh)	Std.Dev (GWh)
JAN	173.68	3.23
FEB	154.51	3.02
MAR	169.18	3.14
APR	168.44	4.48
MAY	189.11	7.90
JUN	211.87	10.98
JUL	245.23	12.39
AUG	247.53	12.39
SEP	217.63	11.79
OCT	191.66	8.35
NOV	168.92	3.97
DEC	175.31	3.29
Annual TOTAL	2313.07	

2.6 Monthly System Peak Model

The regression component of our monthly system peak forecasting model is a function of our two economic drivers (PCPI and EMP), three weather effects that quantify the total monthly cooling needs, maximum three-day cooling requirements (i.e., 3-day heat waves) and the maximum single day heating requirement (SumCD, MaxCD3 and MaxHD, respectively), and six lower order Fourier frequencies (Fs(1), Fc(1), Fs(2), Fc(2), Fs(3) and Fc(3)). The statistical details associated with this forecasting model are presented in Appendix 2. Table 2.6.1 shows the pertinent model fitting and summary statistics for our system peak forecasting equation. This equation again explains approximately 99% of the observed variability associated with the monthly 2004-2011 system peaks.

The estimates for the seasonal variance components are shown at the bottom of Table 2.6.1. These components define how the model mean square error (MSE) changes across the seasons. As with the system load residuals, an analysis of the variance adjusted, peak model residuals suggests that these errors are Normally distributed, devoid of outliers and temporally uncorrelated.

The regression parameter estimates shown in the middle of Table 2.6.1 imply that monthly system peaks increases as each of the weather indices increase (SumCD, MaxCD3 and MaxHD), 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 either the area wide PCPI and/or employment indices improve over time (i.e., both economic parameter estimates are greater than 0). Additionally, not every individual Fourier frequency parameter estimate is statistically significant, although their combined effect significantly improves the forecasting accuracy of the model.

Figure 2.6.1 shows the observed (blue points) versus back-casted, calibrated (green line) system loads for the 2004-2011 timeframe. Nearly all of the calibrations fall within the calculated 95% confidence envelope (thin black lines) and the observed versus calibrated load correlation exceeds 0.989. Figure 2.6.2 shows the forecasted monthly system peaks for 2014 through 2023, along with the corresponding 95% forecasting envelope. This forecasting envelope again encompasses both model and weather uncertainty, while treating the projected economic indices as fixed inputs. As with the system loads, there is considerable uncertainty associated with summer peak forecasts due to the increased uncertainty surrounding summer weather patterns.

Table 2.6.2 shows the forecasted monthly RPU system peaks for 2014, along with their forecasted standard deviations. Once again, these standard deviations quantify both model and weather uncertainty. The 2014 forecasts project that our maximum monthly system peak should be about 577 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 temperature forecast, respectively.

Table 2.6.1 Model summary statistics for the monthly system peak forecasting equation.

Monthly Peak Load Model (Jan 2004 - Sept 2011): MW units
Forecasting Model: includes Weather & Economic Covariates (w/Fourier Effects)

Dependent Variable: Peak Peak (MW)

Number of Observations Read	396
Number of Observations Used	93
Number of Observations with Missing Values	303

Weight: ht_2 (structured seasonal pattern)

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	11	1687851	153441	639.10	<.0001
Error	81	19447	240.08946		
Corrected Total	92	1707299			

Root MSE	15.49482	R-Square	0.9886
Dependent Mean	341.16118	Adj R-Sq	0.9871
Coeff Var	4.54179		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variance Inflation
Intercept	Intercept	1	101.85807	37.75270	2.70	0.0085	0
PCPI	PCPI ($1,000)	1	4.21152	1.18698	3.55	0.0006	1.27497
Emp_CC	Labor (100,000)	1	5.06463	2.14415	2.36	0.0206	1.25466
sumCD	Sum CD's	1	0.11549	0.04624	2.50	0.0145	24.33037
maxCD3	Max 3-day CD	1	2.67030	0.22273	11.99	<.0001	16.86261
maxHD	Max XHD	1	1.39419	0.56402	2.47	0.0155	4.56153
Fs1	Fs(1)	1	-27.05680	4.85113	-5.58	<.0001	4.78835
Fc1	Fc(1)	1	-38.88293	6.41692	-6.06	<.0001	13.62696
Fs2	Fs(2)	1	6.62555	3.78128	1.75	0.0835	2.89319
Fc2	Fc(2)	1	-3.97387	2.90112	-1.37	0.1745	2.39228
Fs3	Fs(3)	1	4.06101	2.57365	1.58	0.1185	2.15623
Fc3	Fc(3)	1	5.36904	2.31039	2.32	0.0226	1.85533

Variance Effect	Label	DF	Parameter Estimate	Standard Error
Fs1	Fs(1)	1	-0.7997	0.3304
Fc1	Fc(1)	1	-0.3527	0.3274
Fs2	Fs(2)	1	-1.1602	0.3503
Fc2	Fc(2)	1	-0.5508	0.3273

Durbin-Watson D	1.994
Number of Observations	93
1st Order Autocorrelation	-0.028

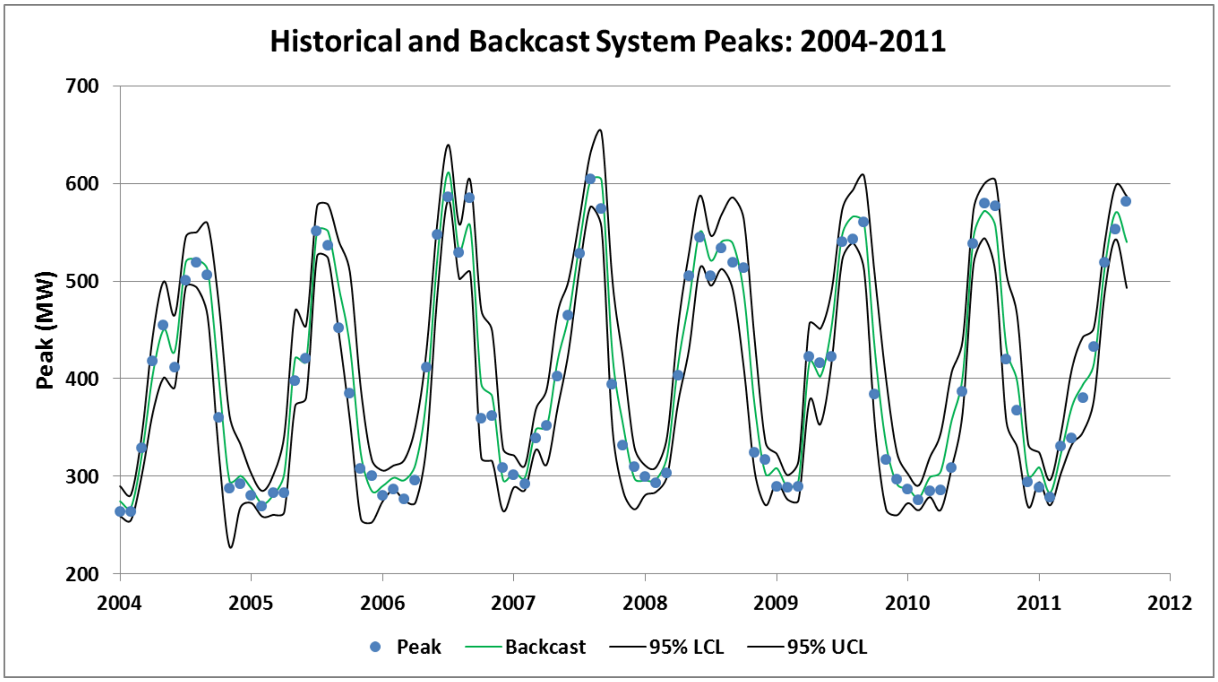


Figure 2.6.1. Observed and predicted system peak data (2004-2011), after adjusting for known weather conditions.

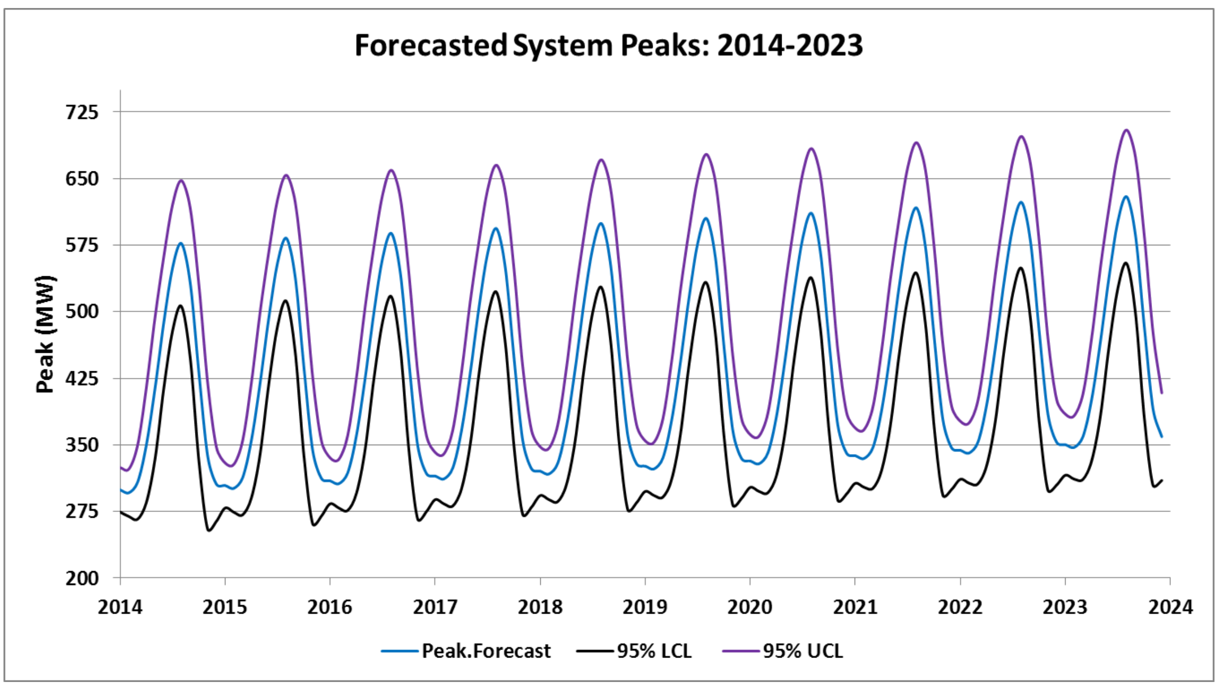


Figure 2.6.2. Forecasted monthly system peaks for 2014-2023; 95% forecasting envelopes encompass both model and weather uncertainty.

Table 2.6.2. 2014 monthly system peak forecasts for RPU; forecast standard deviations include both model and weather uncertainty.

Month	Peak (MW)	Std.Dev (MW)
JAN	299.4	12.5
FEB	296.1	13.3
MAR	308.0	20.9
APR	349.9	32.4
MAY	414.3	39.9
JUN	488.7	37.1
JUL	549.9	35.5
AUG	576.9	35.4
SEP	533.0	42.1
OCT	431.2	49.6
NOV	337.7	41.3
DEC	305.7	20.9

2.7 1-in-K Peak Demand Forecasts

Once the monthly peak forecasts ($Peak_F$) and their corresponding standard deviations that incorporate weather uncertainty ($Std(Peak_F)$) have been estimated, additional peak demand forecasts for more extreme weather scenarios can be produced. Under the assumption that these 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: $Peak_F + 0.842 \times Std(Peak_F)$
- 1-in-10 Peak: $Peak_F + 1.282 \times Std(Peak_F)$
- 1-in-20 Peak: $Peak_F + 1.645 \times Std(Peak_F)$
- 1-in-40 Peak: $Peak_F + 1.960 \times Std(Peak_F)$

In the above equations, 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) quantiles of the Standard Normal distribution, respectively. These formulas are useful for assessing various distribution reliability scenarios, such as when our 1-in-10 Peak is expected to exceed our N-1 contingency limit for our Vista substation plus our internal generation. This topic is discussed in more detail in Chapter 9.

2.8 2014-2033 Load and Peak Forecasts

Based on the previous system load and peak forecasting equations, Table 2.8.1 shows the annual forecasted system loads and peaks for the 2014-2033 time frame (columns 2 and 3). These forecasts represent our future load and peak estimates under our full economic recovery, base case scenario. Note that our expected annual load and peak growth rates under this scenario are 2.4% and 1.1%, respectively. In addition to these forecasts, a weak growth, alternate case scenario is also presented in Table 2.8.1 (columns 4 and 5). Under this alternate scenario our system loads and peaks have been constrained to just 0.5% annual growth rates. This second scenario describes RPU's expected load and peak growth under long term anemic economic conditions.

Table 2.8.1. Annual forecasted system loads and peaks, under both optimistic (strong) and anemic (weak) growth scenarios.

Year	Strong Load Growth (GWh)	Strong Peak Growth (MW)	Weak Load Growth (GWh)	Weak Peak Growth (MW)
2013	2280.17	573.0	2280.17	573.0
2014	2313.09	576.9	2291.57	575.9
2015	2361.93	582.8	2303.03	578.7
2016	2413.40	588.2	2314.54	581.6
2017	2454.65	593.7	2326.12	584.5
2018	2503.41	599.3	2337.75	587.5
2019	2552.81	605.0	2349.44	590.4
2020	2609.25	610.9	2361.18	593.4
2021	2655.67	616.9	2372.99	596.3
2022	2708.58	623.2	2384.85	599.3
2023	2763.49	629.5	2396.78	602.3
2024	2826.11	636.1	2408.76	605.3
2025	2878.34	642.8	2420.81	608.3
2026	2937.78	649.7	2432.91	611.4
2027	2998.80	656.8	2445.07	614.4
2028	3065.99	664.1	2457.30	617.5
2029	3125.85	671.6	2469.59	620.6
2030	3191.92	679.3	2481.93	623.7
2031	3259.78	687.2	2494.34	626.8
2032	3335.15	695.3	2506.82	630.0
2033	3400.51	703.6	2519.35	633.1
Load/Peak Growth 2033 v.s. 2014	2.4%	1.1%	0.5%	0.5%

Conceptually, there are a number of factors that could affect our future expected system loads and peaks. Future economic conditions should tend to be the dominant driver; note that our base case scenario envisions a robust, full economic recovery, followed by an extended period of strong economic conditions (3% annual growth in personal income and 1.5% annual growth in the labor force, respectively). Any extended period of suboptimal economic conditions should depress our load growth accordingly. Other factors that could also reduce our load growth more than currently forecasted include (a) a higher than expected penetration of solar PV installations, (b) significantly increased (and non-strategic) energy efficiency activities, and (c) the need for an excessive increase in retail rates, to compensate for either the cost of increasingly stringent regulatory mandates, or unforeseen spikes in long term fuel prices. Note that we will not attempt to forecast each of these potential effects individually in this IRP analysis, but rather use the alternative, poor load and peak growth scenario as a reasonable, expected lower bound for the potential compilation of such effects. As such, the two sets of load and peak data presented in Table 2.8.1 can and will be used to represent our optimistic (strong) and anemic (weak) growth scenarios, respectively.

3. RPU Generation and Transmission Resources

3.1 Existing and Anticipated Generation Resources

RPU's resource portfolio has evolved over time to address key issues such as CAISO market price volatility, various fuel and delivery risk tolerances, internal generation and distribution needs, and load and peak demand growth. Additionally, our portfolio continues to be shaped by new regulatory mandates, particularly the need to achieve specific greenhouse gas (GHG) reduction targets and a commitment to incorporate an increasing percentage of renewable resources. Table 3.1.1 below presents a high level overview of our current resource portfolio, with respect to both our existing and anticipated resources. Additionally, Figure 3.1.1 shows a map of where these existing and anticipated resources are (or will be) located.

Table 3.1.1. RPU long-term resource portfolio.

Existing Resources	**Technology**	**Capacity (MW)**	**Contract End Date**	**Asset Type**
Intermountain (IPP)	Coal, base-load	136	May-2027	Entitlement/PPA
Palo Verde	Nuclear, base-load	12	Dec-2030	PPA (SCPPA)
Hoover	Hydro, daily peaking	20-30	Sep-2067	PPA (SCPPA)
BPA-2	Exchange, daily peaking	15/60	May-2016	EEA
RERC 1-4	Nat.gas, daily peaking	194	n/a	Owned Asset
Springs	Nat.gas, daily peaking	36	n/a	Owned Asset
Clearwater	Nat.gas, base-load	28.5	n/a	Owned Asset
Salton Sea 5	Geothermal, renewable (base-load)	46	May-2020	PPA
Wintec	Wind, renewable	1.3	Dec-2018	PPA
WKN	Wind, renewable	6	Dec-2032	PPA
Future Resources (under contract)	**Technology**	**Nameplate Capacity (MW)**	**Contract Start & End Dates**	**Asset Type**
AP North Lake	Solar PV, renewable	20	Jul-2015 Jun-2039	PPA
S.Power	Solar PV, renewable	20	Jul-2016 Jun-2040	PPA
Kingbird B	Solar PV, renewable	14	Jan-2016 Dec-2035	PPA
Columbia II	Solar PV, renewable	11	Jan-2015 Dec-2034	PPA
Tequesquite	Solar PV, renewable	7	Jan-2016 Dec-2040	PPA w/PO
CalEnergy Expansion	Geothermal, renewable (base-load)	20/40/86	(Feb-2016, Jan-2019, Jun-2020) Dec-2039	PPA
Cabazon	Wind, renewable	39	Jan-2015 Dec 2024	PPA
Recently Expired Contracts	**Technology**	**Nameplate Capacity (MW)**	**Termination (or Force Majeure) Date**	**Asset Type**
BPA 1	Exchange, daily peaking	16/23	Mar-2011	EEA
SONGS	Nuclear (base-load)	39	Feb-2012 Force Majeure	Ownership interest
Covanta	Waste-to-energy, renewable (base-load)	18	Dec-2013	WSPP contract

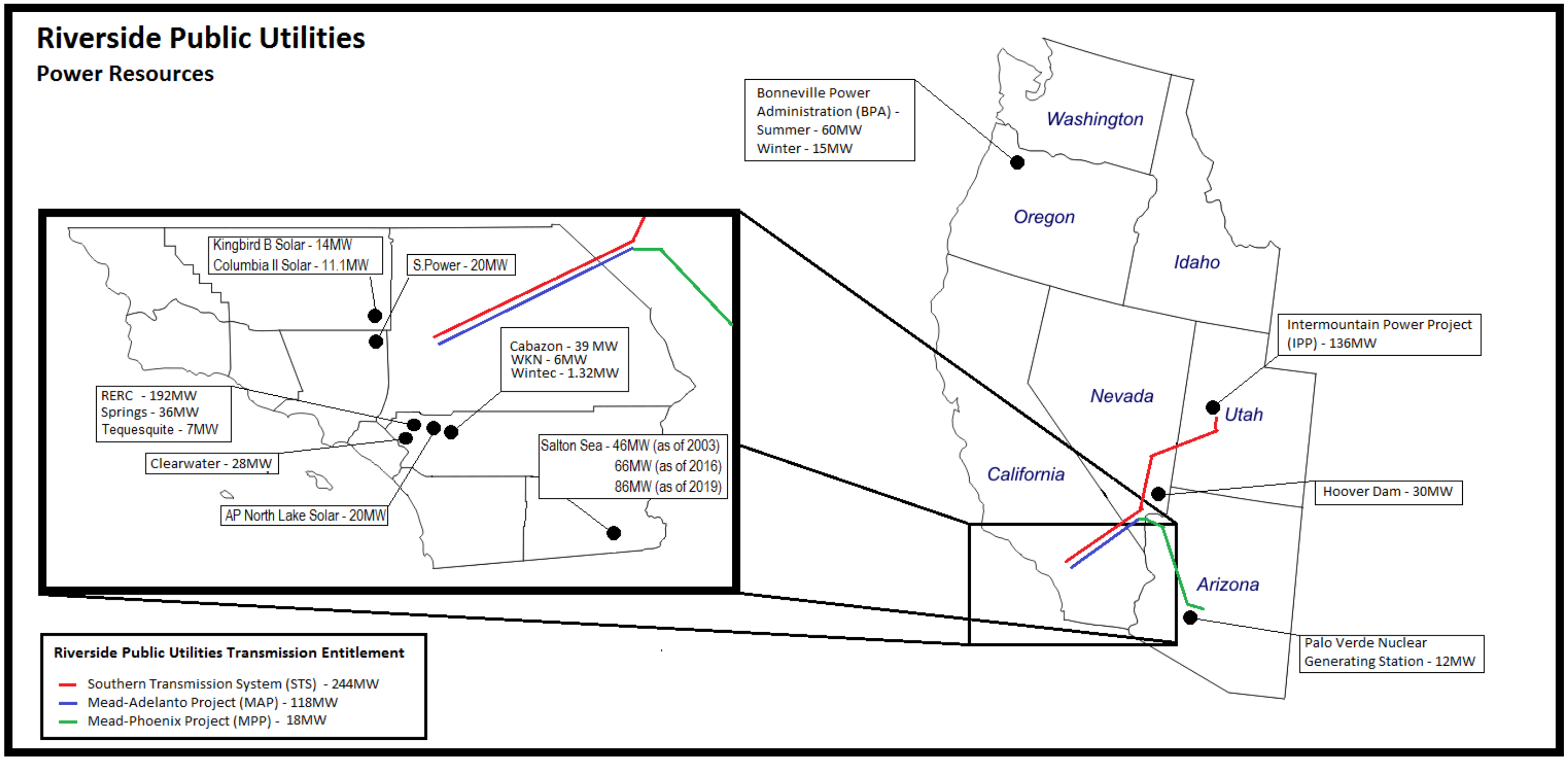


Figure 3.1.1. Physical locations of RPUs existing and anticipated generation resources.

Brief descriptions of each resource referenced in Table 3.1.1 and Figure 3.1.1 are presented below.

3.1.1 Existing Resources

Intermountain Power Project (IPP)

Riverside has contractual rights in the Intermountain Power Project (IPP) for base-load coal energy through May 2027. Specifically, we are entitled to receive 7.617% of the energy output from Units 1 & 2, or 68 MW per hour from each unit. Thus, in a typical year RPU can receive a maximum of 1,048,400 MWh of base-load energy if both plants run at their expected 88% capacity factors.

RPU is required to pay for Riverside's contractual share of debt service costs, fixed O&M costs and take-or-pay coal supply costs whether or not IPP units generate any electricity. In FY11/12, this fixed cost component was $51,129,000, which translated to a fixed capacity cost of $31.33/kW-month and a 61.6% minimum take obligation. (More recently, this minimum take obligation has been decreasing as the long-term fixed-price coal contracts expire.) For all energy above the annual minimum take-or-pay obligation, RPU pays a flat $/MWh energy cost (incremental coal cost); in FY12/13, this variable fuel cost was approximately $22.70/MWh.

Palo Verde Nuclear Facility

Riverside has a long-term contract with SCPPA for ownership rights in the Palo Verde (PV) Nuclear facility. SCPPA officially owns a share of the nuclear facility; RPU in turn has a contract with SCPPA to pay our share of the debt services, capital, O&M, and fuel costs. Riverside's share of PV entitles RPU to 3.9 MW of base-load energy from each nuclear unit (PV-1, PV-2, and PV-3; 11.7 MW total) through December 2030. In FY12/13, RPU paid $22.49/kW-month in fixed capacity costs and $11.51/MWh in energy costs for our share of this base-load nuclear energy.

Hoover

Riverside is a participant in the Hoover Uprating project. Hoover is owned and operated by the United States Bureau of Reclamation, and power from the project is marketed by the Western Area Power Administration. The City has a 31.9% (30 MW) entitlement interest in SCPPA's approximately 94 MW interest in the total capacity and allocated energy of Hoover.

For scheduling purposes, participants in the Hoover project receive a total MWh per month allocation of energy and a maximum hourly capacity limit (as determined by current lake levels). During October 2011 – September 2012, RPU was entitled to approximately 34,500 MWh of Hoover hydro energy, subject to the scheduling limits shown in Table 3.1.2.

Table 3.1.2. 2011-2012 MWh/month and MW/hour scheduling limits for Hoover Dam energy.

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
MWh/month	1674	2384	1923	2599	2907	3776	4451	3487	3032	3143	2853	2264
MW/hour	24	21	25	20	19	25	28	29	30	30	30	30

As of June 2013, Hoover energy cost $11.10/MWh. Additionally, RPU also pays approximately $600,000 annually in fixed capacity costs (or $17.39/MWh, based on an expected delivery of 34,500 MWh of annual energy).

BPA-2

Our BPA-2 contract is actually an energy exchange agreement (EEA) between Riverside and Bonneville Power Authority. Hence, there are no fixed capacity costs or energy costs per se; rather, the value of the contract depends upon the current energy prices in the SP15 and Mid-C markets. The exchange energy contract rules are fairly involved, but in general entitle RPU to receive a maximum of 15 MW per hour, 6 hours per day during the winter months (November-April) and 60 MW per hour, 6 hours per day during the summer months (July-October). RPU also receives seasonal firm energy deliveries during May and June (40 MW per hour, 24 hours per day, 7 days a week) and must return all winter and summer peaking energy within a 24 hour period, by either wheeling power back up the NOB line or purchasing an appropriately sized off-peak energy product at Mid-C. Riverside must also return a total of 64,350 additional MW over the period of November 1 through April 15, during off-peak hours only. This additional energy (along with our seasonal firm energy return obligation) is typically covered using forward purchased Mid-C energy products.

Our current BPA-2 contract terminates on April 30, 2016. Thus, RPU will lose the 60 MW of firm Q3 peaking capacity associated with this EEA in summer 2016.

RERC Units 1-4

Riverside owns and operates four LM6000 peaking units; these units are collocated together at the RERC generation facility in the center of Riverside and connected directly to our local distribution system (69kV lines). RERC Units 1 and 2 become operational in 2006; RERC Units 3 and 4 came on-line in 2011. All four units have P_{max} heat rates of 9,600 (Btu/kWh), net P_{max} outputs of 48.4 MW/hour per unit, and are certified to provide both energy and ancillary services to the CAISO.

The annual and/or monthly runtime limits on each unit are related to our air quality pollution control permit limits. For RERC units 1 and 2, the primary limits are the 1200 hour maximum runtime constraints in any rolling 12 month window. For RERC units 3 and 4, the primary constraints are the 225 hour/month runtime limits, 1800 hour annual limits, and 40 starts-per-month constraints. Theoretically, these four units could generate 290,000 MWh of energy per year, although in practice these units typically produce 50,000 to 80,000 MWh a year (under economic dispatch).

Springs (Units 1-4)

Riverside also owns and operates four GE10 peaking units; these units are collocated together at the Springs generation and distribution facility in the eastern part of of Riverside. Springs units 1-4 were brought on-line in 2002 (after the last energy crisis), to increase reliability and serve basic emergency power needs. All four units have P_{max} heat rates of approximately 14,000 (Btu/kWh) and net P_{max} outputs of 9 MW/hour per unit.

Generation hours for our GE10 units are primarily limited by the unit's inefficient heat rates; e.g., these units typically produce just 1,000 to 4,000 MWh a year under economic dispatch. Currently, these units are primarily used for distribution system voltage support and meeting local RA requirements.

Clearwater

Riverside owns and operates one additional small combined-cycle (cogeneration) plant located in the city of Corona, CA. This facility is certified to provide energy and RA to the CAISO, but not ancillary services. Although Clearwater lies outside of the RPU service territory, the CAISO classifies all energy generated from this facility as internal RPU generation.

Clearwater has a combined-cycle P_{max} heat rate of 8,600 (Btu/kWh) and a net output of 28 MW/hour. RPU has sufficient AQMD permits to dispatch this unit on a 6 x 16 schedule all year, but Clearwater is typically out-of-the-money during most heavy load hours outside of Q3. In CY 2012, Clearwater was dispatched approximately 900 hours and generated 25,000 MWh of energy.

Salton Sea 5

Riverside entered into a ten-year PPA in 2003 for 20 MW of base-load geothermal energy generated by the CalEnergy Salton Sea 5 facility located in Imperial County, California. In 2005, Riverside and CalEnergy amended this PPA to increase the amount of renewable energy from 20 MW to 46 MW effective June 1, 2009 through May 31, 2020 at a price of $61.00/MWh. On July 1, 2013 the contract energy price was increased to $69.66/MWh as part of the pre-pay agreement for the CalEnergy Expansion contract.

Salton Sea 5 is a traditional take-and-pay PPA with a historic base-load, outage-adjusted capacity factor of 76% to 87% (depending upon system performance). Traditionally, the Salton Sea 5 unit has delivered between 295,000 to 350,000 MWh of renewable base-load energy on an annual basis to RPU.

Wintec Wind

In 2003, Riverside and Wintec-Pacific Solar, LLC entered into a fifteen year PPA for 1.3 MW of wind energy generated from the Wintec project near Palm Springs, California. This take-and-pay renewable wind resource typically delivers around 4,500 MWh of intermittent renewable energy to RPU. As of June 2013, RPU paid $54.29/MWh for this energy.

WKN Wind

In 2012, Riverside and WKN-Wagner, LLC entered into a twenty year PPA for 6 MW of wind energy generated from the WKN project near Palm Springs, California. This take-and-pay renewable wind resource is expected to deliver about 19,000 MWh of intermittent renewable energy to RPU. As of June 2013, RPU paid $62.50/MWh for this energy.

3.1.2 Future Resources

AP North Lake Solar PV

In 2012, Riverside and SunEdison entered into a bilateral twenty five year PPA for the 20 MW AP North Lake solar PV project in Hemet, California. This take-and-pay renewable solar resource is expected to deliver about 55,500 MWh of intermittent energy to RPU, beginning in July 2015. The starting price for this energy is $83.90/MWh (with a 1.5% annual escalation rate), and includes all RA attributes.

S.Power Solar PV

In 2012, Riverside also executed an agreement with the Southern California Public Power Authority (SCPAA) to participate in a twenty five year PPA for the 40 MW Silverado Antelope Valley solar PV project in Lancaster, California. In early 2014, Silverado merged with S-Power Inc., and this contract was renegotiated. Riverside's share of this project is 20 MW; this take-and-pay renewable solar resource is expected to deliver about 45,000 MWh of intermittent energy to RPU, beginning in July 2016. The price for this energy is $71.25/MWh flat, and includes all RA attributes.

Kingbird B

In 2013, Riverside executed an agreement with SCPAA to participate in a twenty year PPA for the 20 MW Kingbird B PV project in Rosamond, California. Riverside's share of this project is 14 MW; this take-and-pay renewable solar resource is expected to deliver about 41,800 MWh of intermittent energy to RPU, beginning in January 2016. The price for this energy is $68.75/MWh flat for twenty years and includes all RA attributes.

Columbia II (Recurrent) Solar

In 2013, Riverside executed a second agreement with SCPAA to participate in a twenty year PPA for the 35 MW Recurrent solar PV project to be developed on two sites in Mojave, California. Riverside's original share of this project was 26 MW. In early 2014, Recurrent announced that development could not proceed on the larger site, thus Riverside's share of this project was reduced to just 11 MW of the Columbia II site. This take-and-pay renewable solar resource will deliver about 33,400 MWh of intermittent energy to RPU, beginning in January 2015. The price for this energy is $69.98/MWh flat for twenty years and includes all RA attributes.

Tequesquite Solar

In February 2014 Riverside finalized a twenty five year bilateral PPA with SunPower to develop a 7 MW solar PV facility on the Tequesquite landfill site in the city of Riverside, California. This take-and-pay, distributed generation solar resource is expected to deliver about 15,700 MWh of intermittent energy to RPU, beginning in June 2015. The starting price for this energy is $81.30/MWh (with a 1.5% annual escalation rate), and includes all RA attributes.

CalEnergy Geothermal Expansion Project

In 2013 Riverside successfully concluded contract negotiations with CalEnergy LLC to significantly increase the amount of geothermal energy delivered from the CalENergy Salton Sea geothermal portfolio. Under this new contract, Riverside will begin receiving an additional 20 MW of base-load geothermal energy from the portfolio in February 2016, which will then increase to 40 MW in January 2019. Additionally, when the Salton Sea 5 contract terminates in June 2020, Riverside will simultaneously begin receiving an additional 46 MW of energy from the geothermal portfolio (thus maintaining 86 MW of total geothermal capacity in our resource portfolio). The 2016 starting price for this additional energy is $72.85/MWh (with a 1.5% annual escalation rate), and includes all RA attributes.

This contract serves as the cornerstone for Riverside's strategy to meet/exceed our 33% RPS mandate by 2020. Each incremental 20 MW entitlement should provide RPU with an additional 152,400 MWh of base-load renewable energy, increasing the total annual geothermal energy amount in our portfolio to approximately 656,000 MWh annually by 2019.

Cabazon Wind

In 2013, Riverside also entered into a bilateral ten year PPA with Nextera for the 39 MW Cabazon Wind Energy project located near North Palm Springs, California. This existing take-and-pay renewable wind resource is expected to deliver about 71,500 MWh of intermittent energy to RPU, beginning in January 2015. The price for this energy is $59.30/MWh flat for ten years and includes all RA attributes.

3.1.3 Recently Expired Contracts

BPA 1

Our BPA-1 contract was a prior energy exchange agreement (EEA) between Riverside and Bonneville Power Authority that expired in March 2011. This contract entitled RPU to receive a maximum of 16 MW per hour, 6 hours per day during the winter months (November-April) and 23 MW per hour, 6 hours per day during the summer months (July-October), along with additional seasonal firm energy deliveries during May and June. All return energy was either wheeled back up the NOB line or purchased at Mid-C. Upon the expiration of this contract, RPU lost 23 MW of firm Q3 peaking capacity.

San Onofre Nuclear Generating Station (SONGS)

Riverside has a 1.79% undivided ownership interest in Units 2 and 3 of SONGS, located south of the City of San Clemente in northern San Diego County. RPU had received 39.5 MW of firm local capacity and approximately 290,000 MWh per year from Units 2 and 3, respectively, before SONGS went off-line in early 2012 due to excessive steam-tube wear. SONGS is operated and maintained by SCE under an agreement with Riverside and SDG&E. In the summer of 2013, SCE elected to permanently shut down SONGS, due to the ongoing economic uncertainty surrounding the repair of the steam turbines (and the potential complication of relicensing of the nuclear generation facility).

Under the current participation agreement, Riverside is entitled to its proportionate share of benefits from the SONGS facility. Additionally, Riverside must pay its proportionate share of costs and liabilities incurred by SCE for construction, operation and maintenance of the SONGS facility. As of June 2013, Riverside owed $36.8 million dollars in outstanding bond debt related to SONGS costs and liabilities. Additionally, Riverside is also responsible for its share of expenses associated with all decommissioning activities. In a study dated July 2013 and prepared by ABZ, Incorporated on behalf of the participants in SONGS, the cost of decommissioning SONGS Units 2 and 3 was estimated to be approximately $4.132 billion, based on 2011 dollars, of which Riverside's share is $74.0 million. The City had deposited $76.0 million in its decommissioning trust funds as of June 2013.

Covanta

In December 2012, Riverside entered into a short-term, twelve month WSPP agreement with Covanta Energy Marketing LLC to purchase renewable energy from the Stanislaus Energy-from-Waste (EFW) facility in Crows Landing, California. This EFW facility can generate 18 MW of base-load power; as of November 30, 2013 this facility had delivered about 149,000 MWh of renewable energy to RPU.

In July 2013, this WSPP agreement was extended for one additional month (i.e., through December 31, 2013), so that RPU could obtain more Portfolio Content Category 1 renewable energy during Compliance Period 1. Under both the WSPP agreement and extension, RPU paid $65.25/MWh for this energy.

3.2 Transmission Resources

Riverside has historical ownership rights to various transmission resources; these resources are described in more detail below.

Southern Transmission System

In connection with its entitlement to the IPP Generating Station, the City acquired a 10.2% (195 MW) entitlement in the transfer capability of the 500-kV DC bi-pole transmission line, known as the Southern Transmission System (STS). The STS provides for the transmission of energy from, among other resources, the IPP Generating Station to the California transmission grid. The STS provides approximately 2,400 MW of transfer capability. The City's total entitlement in the STS increased from 195 MW to 244 MW after the STS upgrade was completed in January 2011.

Mead-Phoenix Transmission Project

Originally in connection with its entitlement to PVNGS power, the City has acquired a 4% (12 MW) entitlement in SCPPA's share of the Mead-Phoenix Transmission Project, separate from the SCPPA interest acquired on behalf of the Western Area Power Administration. The Mead-Phoenix Transmission Project consists of a 256-mile, 500-kV AC transmission line that extends between a southern terminus at the existing Westwing Substation (in the vicinity of Phoenix, Arizona) and a northern terminus at Marketplace Substation. The Mead-Phoenix Transmission Project was upgraded in June 2009 as part of the East of River 9300 Project. The City receives an additional 6 MW entitlement in the Mead-Phoenix Transmission Project from the upgrade.

Mead-Adelanto Transmission Project

In connection with the Mead-Phoenix Transmission Project, the City has acquired a 118 MW entitlement to SCPPA's share of the Mead-Adelanto Transmission Project. The Mead-Adelanto Transmission Project consists of a 202-mile, 500-kV AC transmission line that extends between a southwest terminus at the existing Adelanto Substation in southern California and a northeast terminus at Marketplace Substation. SCPPA currently owns 67.9% of this 500-kV transmission line; this line has a transfer capability of 1,286 MW.

Riverside Transmission Reliability Project

Riverside has historically relied upon a single point of electrical interconnection to California's bulk power transmission system, but the City is now pursuing the creation of a second point of interconnection to significantly enhance its system reliability and import capacity. The City has an interconnection facilities agreement with SCE for the construction and interconnection of a new 230-69 kV transmission substation which will provide another interconnection of the City's system with SCE's transmission facilities. The $125 million dollar project is known as the Riverside Transmission Reliability Project (RTRP) and will include a 230-69 kV transmission substation as a second point of interconnection to the California transmission grid. RTRP is discussed in more detail in Section 4.7.

3.3 California Independent System Operator

The City serves as its own Scheduling Coordinator with the CAISO and was the first California municipal utility to do so. In July 2002, the City notified the CAISO of its intent to become a Participating Transmission Owner (PTO) by turning over operational control of the City's transmission entitlements to the CAISO, effective January 1, 2003. In November 2002, the City formally executed its Transmission Control Agreement with the CAISO.

On January 1, 2003, the City became a PTO with the CAISO, entitling the City to receive compensation for the use of its transmission entitlements committed to the CAISO's operational control. The compensation is based upon the City's annual Transmission Revenue Requirement (TRR) as approved by the FERC. The City now obtains all of its transmission requirements from the CAISO. With the launch of the Market Redesign and Technology Upgrade (MRTU), the CAISO also implemented a

Congestion Revenue Rights (CRR) allocation and auction process. The City participates in the CAISO CRR process to obtain the additional transmission congestion hedging rights necessary to hedge the majority of its load serving transmission requirements.

3.4 RPU Current Resource Procurement Strategy

In recent years, RPU's resource portfolio has been comprised of a blended amount of coal, nuclear, natural gas and geothermal generation resources, along with some strategic hydro and energy exchange contracts to help meet our summer peaking needs. However, this resource portfolio is currently undergoing a transformation, specifically away from nuclear and coal and towards more renewable resources. With the (force majeure) loss of SONGS in February 2012, RPU has had both the need and opportunity to replace a nuclear resource that supplied 39 MW of firm, GHG-free base-load capacity (and approximately 290,000 MWh of annual energy) with a replacement base-load contract having equivalent characteristics. Thus, in 2013, RPU entered into the long-term PPA with CalEnergy LLC to significantly expand our base-load geothermal resources. In February 2016, RPU will begin receiving an additional 20 MW of base-load geothermal energy from the CalEnergy geothermal resource portfolio located in Imperial Valley, CA. This amount will increase to 40 MW in January 2019 and then to 86 MW in June 2020 (immediately after the expiration of our current 46 MW Salton Sea 5 contract). Note that by January 2019, these 86 MW of geothermal capacity should supply RPU with approximately 656,000 MWh of base-load renewable energy.

Concurrently with the contracting of these new geothermal resources, RPU has also entered into six new renewable PPAs (AP NorthLake, S.Power, Kingbird B, Columbia II, Tequesquite, and Cabazon). Combined, these five solar PV and one wind resource carry 111 MW of nameplate capacity and are expected to contribute 65 MW towards our summer resource adequacy needs, supply 268,000 MWh of annual energy, and meet nearly 12% of our renewable RPS target by 2017. Thus, Riverside's resource portfolio will incorporate increasing amounts of new solar and wind resources over the next five years, in addition to the aforementioned renewable geothermal resources.

Together, these new PPA's will contribute a significant expansion of capacity and renewable energy to RPU's current resource portfolio. By 2019, Riverside expects to serve almost 37% of its retail load using renewable resources. The combined effects of these new renewable resources on RPU's portfolio are presented in Chapter 8, along with additional power resource metrics on our forecasted net positions, internal generation, and GHG emissions. Likewise, a more in-depth discussion of RPU's long-term capacity and RPS energy needs is presented in Chapter 9.

4. RPU Existing Electric System

This section briefly reviews RPU's existing electric system and describes how it operates. RPU is a vertically integrated utility that operates electric generation, sub transmission, and distribution facilities. Power is delivered to RPU through the regional bulk transmission system operated by the CAISO.

4.1 Energy Delivery Division

The Energy Delivery Division is responsible for managing and maintaining RPU's sub transmission and distribution facilities. The Energy Delivery Division's main purpose is to effectively manage activities related to the transmission and delivery of electricity to RPU's customers. The three primary objectives of the Energy Delivery Division are to:

- Ensure electric service reliability,
- Operate and maintain the distribution system safely, efficiently, and in compliance with regulatory requirements, and
- Maintain a single point where all accountabilities reside related to energy transmission and delivery.

4.2 System Interconnections

RPU's electrical interconnection with the California transmission grid is established at the Southern California Edison's Vista Substation, northeast of the RPU system. RPU currently takes delivery of the electric supply at 69-kV through two 280 MVA transformers. The transformers are connected to the RPU electric system by seven 69 kV sub transmission lines. The RPU electrical system is comprised of 15 separate substations linked by a network of 69 kV and 33kV lines. Each substation transforms the power on the system from 69 kV /33 kV to 12 kV/4 kV for distribution to the RPU customers.

Figure 4.2.1 illustrates the existing RPU sub transmission electrical system. The existing RPU sub transmission system includes facilities constructed and operated at 69 KV and 33 kV. This includes 91 circuit miles at 69kV and 6.5 circuit miles at 33 kV. The sub transmission system serves 11 distribution substations, the RERC and Springs generation stations, and two customer stations (Alumax and Kaiser). The sub transmission system is operated in closed loops.

4.3 Substations

RPU owns and operates 15 substations that fall into three categories: distribution, customer, and generation. The 10 distribution substations served at 69 kV include 12 kV distributions, with four of these substations also including 4-kV distribution. The Freeman and Riverside substations include facilities that serve the older 33-kV sub transmission system, which supplies the Magnolia, and Riverside 4-kV distribution substations. Table 4.3.1 presents RPU's substations and their types and ratings in alphabetical order.

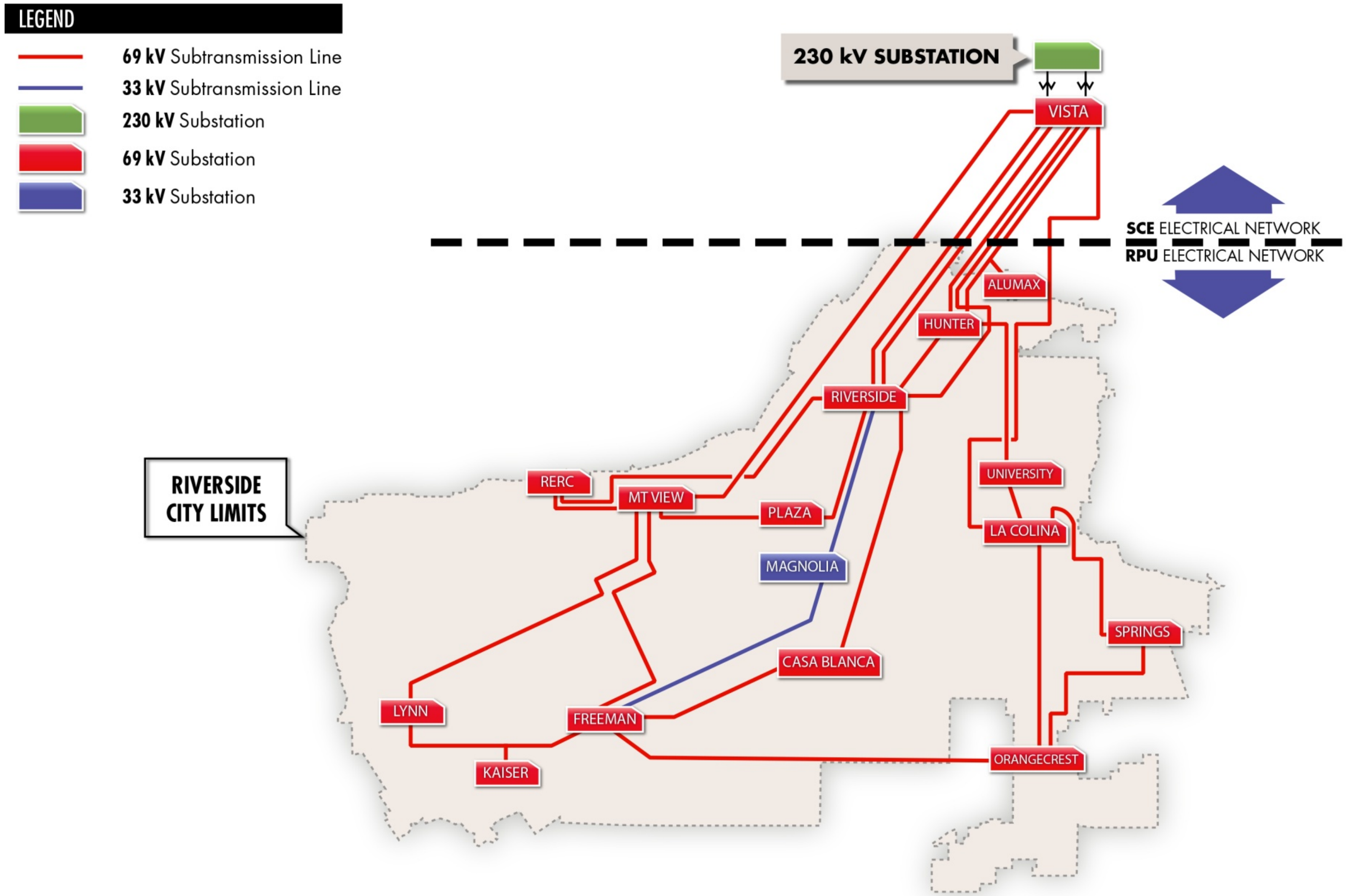


Figure 4.2.1. Existing RPU sub transmission electrical system, excluding the Rohr substation.

Table 4.3.1. RPU substations; type and rating definitions.

Substation	Type	Rating
Alumax	Customer	69-4 kV
Casa Blanca	Distribution	69-12.5 kV
Freeman	Distribution	69-12.5 kV & 69-33 kV
Harvey Lynn	Distribution	69-12.5 kV
Hunter	Distribution	69-12.5 kV & 69-4 kV
Kaiser	Customer	69-4 kV
La Colina	Distribution	69-12.5 kV
Magnolia	Distribution	33-4 kV
Mountain View	Distribution	69-12.5 kV & 69-4 kV
Orangecrest	Distribution	69-12.5 kV
Plaza	Distribution	69-12.5 kV & 69-4 kV
RERC	Generation	69 kV
Riverside	Distribution	69-12.5 kV & 69-33 kV & 33-4 kV
Springs	Generation and Distribution	69-12.5 kV
University	Distribution	69-12.5 kV & 69-4 kV

RPU substations connected to the 69-kV sub transmission system are configured in four typical electrical bus configurations: single bus, sectionalized bus, ring bus, and breaker-and-a-half. Table 4.3.2 lists the configurations currently in use at each substation.

Table 4.3.2. RPU substation configurations.

Single Bus	Sectionalized Bus	Ring Bus	Breaker-and-a-Half
Alumax Kaiser	Casa Blanca Hunter * Magnolia * Mt. View * Plaza * Rohr University *	Freeman * Harvey Lynn * La Colina Orangecrest Springs	RERC Riverside

* Multiple transformers in a single security node

4.4 Protection and Control Systems

For most of the older 69-kV line protection schemes, primary protection is provided by high-speed pilot wire relays (ABB HCB) while the current standard for line protection uses line current differential relays (SEL 387L). Backup protection for the 69-kV lines is a mixture of directional overcurrent in the older relay schemes and step-distance in the newer schemes.

Supervisory control and data acquisition (SCADA) systems send supervisory control commands to remote equipment and acquire status and analog data from remote equipment and systems. The current RPU SCADA system was installed in 2007, including SCADA software provided by Open systems International (OSI) packaged under the Monarch product name.

4.5 Distribution Circuits

RPU's overhead distribution network contains 513 miles of distribution circuits (feeders) and operates both 4-kV and 12-kV with approximately 23,000 poles. The majority of RPU's load is served from the 12-kV system. RPU has 92 miles of 4-kV. About 15 percent of RPU's load continues to be served from the 4-kV system.

RPU's underground distribution network contains cables of various types, sizes, and ages. There are over 800 miles of underground 15-kV and 5-kV class cable in the RPU system. RPU has approximately 3,900 vaults and substructures. These subsurface enclosures include vaults, manholes, commercial subsurface transformer enclosures, and pull-boxes.

4.6 Metering Systems

A variety of electric meters are deployed to support RPU's rate schedules and various service types, including flat rate; single-phase and three-phase demand; time-of-use; and net metering, among other service types. Remote-reading radio frequency meters (ERT meters) are commonly used when there is no physical access to read the dials of the meter because of a safety hazard, or access is prevented by a locked or inaccessible location.

Meter reading data is kept in the MVRS and MV90Xi meter reading systems. The MVRS system is used for retrieving monthly meter readings for billing purposes. Information retained includes meter reads, meter location, and notes of safety. MV90Xi is a repository of interval data from more complex meters. Meter data for the MV90Xi system is gathered by meter-reading handheld devices, laptops that interrogate the meters, and remote communication (telephone or cellular) links.

4.7 Riverside Transmission Reliability Project (RTRP)

RPU's mission statement includes a commitment to provide the highest quality electrical service to its customers. The Board of Public Utilities, which sets all policy guidelines for RPU, has been concerned since the early 1990s about the interconnection capacity of the system to meet our peak demand, as well as the reliability of the existing single point of service within the regional transmission system. Since 2006, the City's electric demand has exceeded the capacity of the interconnection with the regional system.

In 2004, pursuant to SCE's FERC-approved Transmission Owner Tariff, RPU made a request to SCE to develop a means to provide additional transmission capacity to meet RPU projected load growth and to provide a second interconnection for system reliability. SCE determined that in order to meet RPU's request, SCE should expand its regional electrical system to provide RPU a second source of transmission capacity to import bulk electric power. This expansion would be accomplished by the:

- Creation of a new SCE 230 kV transmission interconnection
- Construction of a new SCE substation
- Construction of a new RPU substation, and
- Expansion of the RPU 69 kV system.

The proposed Riverside Transmission Reliability Project (RTRP) would provide RPU with long-term system capacity for load growth, along with needed system reliability and flexibility.

If ultimately approved and developed, the additional transmission capacity would become available through a new substation, named Wildlife Substation. Wildlife Substation would be a 230 kV substation owned and operated by SCE. This substation would be connected to the electric transmission grid by connecting to the existing Mira Loma to Vista #1 transmission line. The voltage of the electrical power would be transformed to 69 kV for integration into the RPU electrical system serving the City. This transformation of power from 230 kV to 69 kV would take place at a second new substation, named Wilderness Substation. Wilderness Substation would be a 230/69 kV substation owned and operated by RPU. The Wildlife and Wilderness Substations would be located within the City of Riverside, adjacent to each other on property that is presently owned by RPU.

5. Important Legislative and Regulatory Mandates and CAISO Initiatives

This chapter outlines the relevant legislative, regulatory and stakeholder issues that will have significant impact to the California electric energy industry in the foreseeable future; specifically to the markets run by the CAISO. An assessment of each issue's current and potential future impact on RPU is also provided.

5.1 Legislative and Regulatory Mandates

5.1.1 SB X1-2 – Renewable Portfolio Standard (RPS)

The California state legislature passed SB X1-2 RPS in 2011 which mandates that in-state electric utilities to procure defined % of renewable resources to serve retail loads. The specific targets are:

- Calendar years 2011-2013 – average of 20% of retail load for the 3-year period.
- Calendar years 2014-2016 – no less than 25% of retail load by no later than calendar year 2016.
- Calendar years 2017-2020 – no less than 33% of retail load by no later than calendar year 2020.
- Calendar year 2021 and beyond – no less than 33% of retail load each year.

In addition, the procurement of renewable resources must be predominantly from in-state renewable resources, e.g., starting 2017, 75% of renewable resources within the target must be located in-state and no more than 10% can be from tradable renewable energy credits (TREC's).

The implementation of SB X1-2 will have a significant impact to the CAISO markets in the foreseeable future. It is anticipated that an overwhelming majority of renewable resources procured by the electric utilities to meet the RPS mandate will be intermittent in nature, e.g. solar and wind, causing significant operational issues (e.g. steep ramping requirements and severe over generation when load is low). Further, such large amount of renewable resources will significantly pressure the economic viability of conventional resources (natural gas plants), especially vintage conventional resources that are already only marginally cost-effective. In turn, this may lead to the early retirement of these vintage conventional resources that are needed to maintain grid reliability when intermittent renewable resources are not available. CAISO has instituted several market initiatives to deal with the grid integration issues caused by SB X1-2 mandate (see section 5.2). Nonetheless, the operational uncertainty caused by RPS mandate will likely be the single largest issue that CAISO will need to manage in the coming years.

With respect to the current RPS paradigm, Riverside is already well positioned to comfortably exceed all current state specified renewable mandates for at least the next 10 years (e.g., through 2023). Our recent PPA's for the new renewable generation assets discussed in Chapter 3 should ensure that RPU serves nearly 37% of its retail load from in-state RPS resources by 2019 (under a normal load growth scenario). Currently, we do not anticipate needing to purchase or contract for any additional renewable generation assets before 2024, assuming that the 33% mandate is not increased after 2020. (Chapter 9 presents a much more detailed discussion on our long-term RPS forecasts.)

5.1.2 AB 32 – California Greenhouse Gas (GHG) Reduction Mandate

The state legislature passed AB 32 in 2006 which mandated statewide reduction of GHG emissions to 1990 levels by calendar year 2020. The California Air Resources Board (CARB) is the lead regulatory agency implementing the AB 32 directives. CARB finalized its implementation regulations in early 2012 and the compliance requirements commenced as of January 2013.

Under the implementation regulations, CARB adopted a market-based program designed to reduce GHG emissions from multiple sources. The Cap-and-Trade program sets a limit on GHG emissions and makes an effort to minimize the cost of compliance with AB 32s goals. CARB's intent with the Cap-and-Trade program is to reduce GHG emissions by creating a carbon market, effectively incentivizing entities to reduce their carbon footprint by assigning a cost to emissions. One GHG emission allowance equates the right to emit one metric ton of GHG emission. All covered entities must have sufficient GHG emission allowances to offset their GHG emissions at the end of each compliance period.

To ease the transition into the new carbon market, California electric utilities were given free allowances from 2013 to 2020 to mitigate the costs of GHG emission reduction activities, and to protect ratepayers from the additional costs caused by the GHG regulations. These free allowances decline over time with the expectation that electric utilities will achieve commensurate GHG emission reductions over time. The Investor Owned utilities must sell all their free allowances into Cap-and-Trade allowance auctions (4 auctions per year) and buy back the allowances they need for compliance purposes either from the Cap-and-Trade auctions or in the open market for allowances. POU's can use their free allowances directly for compliance purposes without selling them into the auctions.

CARB's allowance auctions began in 2012 with an initial floor price of $10/allowance; this price is adjusted annually at CPI plus 5%. The quarterly auctions do not have a hard ceiling price at this time. However as a cost containment measure, CARB can make available a limited amount of allowances at a price not to exceed $50 per metric tons to covered entities. CARB has stated that they will invoke this cost containment measure if the price of allowances in the auctions or in the open market significantly exceeds the $50/allowance mark.

RPU is a covered entity under Cap-and Trade as a First Deliverer of Electricity for both operating electricity generating facilities in California, and also for importing electricity into California. As a covered entity, Riverside is required to report annual greenhouse gas emissions to the CARB under the CARB's Mandatory Reporting Regulations (MRR). CARB monitors emission reduction efforts through the mandated reporting.

As a generating facility, Riverside is mandated to report emissions from its Clearwater generation plant and Riverside Energy Resources (RERC) generation facility. (The Springs generation facility has not been required to be reported due it emitting less than the applicability threshold of 25,000 metric tons or more of CO_2e per year.) As an importer of electricity, Riverside is also required to report emissions from any generation imported into the state of California. Purchases of electricity from within California, such as market purchases directly from the California ISO or purchases from in-state generation plants, are not covered emissions under the MRR, and are not required to be reported. Thus, Riverside's emissions mandated to be reported under AB 32 are currently our imports from the Intermountain Power Project, Bonneville Power Administration, and unspecified sources, and generation from Clearwater and RERC. The large majority of Riverside's covered emissions are from imports from Intermountain Power Project.

Since the CAISO runs a centralized energy market in its footprint, the cost of GHG emission allowances have already being felt in the wholesale electricity markets, adding between $3/MWh to $6/MWh to the wholesale energy price. Likewise, the expectation is that the cost of GHG emission embedded in the cost of electric energy will increase over time as GHG reduction targets get more stringent over time. Currently, RPU has sufficient GHG allowances to fully cover our direct emissions (e.g., from our imports and internal generation), but not quite enough excess allowances to monetize in order to recover our indirect costs (e.g., from the inflated wholesale energy costs). Additional details on our 5-year forward GHG exposure forecasts are presented in Chapter 8.

The major economic risk to RPU (and for that matter, all California electric utilities) under this program occurs after 2020. More specifically, at this time it is unclear whether CARB will be mandated to continue issuing a reduced amount of free allowances after 2020. RPU will not be able to substantially reduce its GHG footprint until our IPP coal contract expires. In the absence of additional free allowances after 2020, RPU could potentially face a 20 million dollar per year emission liability (assuming annual emissions of 800,000 tonnes at $25/tonne).

5.1.3 SB 1368 – Emission Performance Standard

The state legislature passed SB 1368 in 2006 which mandates that electric utilities are prohibited to make long term financial commitments (commitments greater than 5 years in duration) for generating resources with capacity factors > 60% that exceed GHG emission of 1,100 lbs/MWh. SB 1368 essentially prohibits any long term investments in generating resources based on coal. Thus, SB 1368 disproportionally impacts Southern California POU's as these utilities have heavily invested in coal technology.

As discussed in Chapter 3, Riverside has ownership entitlement rights to 136 MW of the Intermountain Power Plant (IPP). IPP has a GHG emission factor of approximately 2,000 lbs/MWh, hence under SB 1368 Riverside is precluded from renewing its IPP Power Purchase Contract at the end of current term in June 2027.

Going forward, SB 1368 related issues are expected to have minimal impact to the CAISO markets as the percentage of California load served by coal resources is small. However, to the extent that significant numbers of coal plants throughout the Western US start to retire in the next 5 to 15 years, it is certainly conceivable that there could be a tightening of supply throughout the Western US electricity market. In turn, this could lead to higher regional costs and potentially reduced system reliability.

5.1.4 Once-Through-Cooling (OTC) Mandate

The State Water Control Board finalized its OTC policy in the past two years; this policy mandates that thermal power plants located along coastal areas reduce their ocean water intake for generating plant cooling purposes by up to 95% to protect the marine life and environment. The compliance dates with the OTC policy vary with each plant, but start as early as 2018 and run through 2030. Approximately 15,000 MW thermal plant capacity is affected by the OTC policy, which is more than one-third of the existing California's generating fleet. Unfortunately, the majority of OTC plants are located in Southern California.

Although RPU is not directly impacted by this mandate (we do not currently contract with any OTC generation assets), the OTC policy is still expected to create significant system-wide challenges in the CAISO, particularly in the south. Most of the existing OTC plants are merchant generating plants that do not have long term power contracts with traditional utilities and hence the plant owners are not expected to make significant financial investments to their plants without assurance of investment recovery. Additionally, these same plants typically face very stringent local air quality emission regulations, along with fierce local opposition to most coastal plant repowering options. For these reasons, most of the coastal OTC plants are expected to retire within the next 5-15 years, potentially further decreasing the reliability of the southern California power grid.

5.1.5 AB 2514 -- Energy Storage (ES)

AB 2514 "Energy Storage Systems" was signed into law on September 29, 2010. The law directs the governing boards of publicly-owned utilities (POUs) to consider setting targets for energy storage procurement but emphasizes that any such targets must be consistent with technological viability and cost effectiveness. The law's main directives for POUs and their respective deadlines are as follows: (a) to open a proceeding by March 1, 2012 to determine appropriate targets, if any, for the utility to procure viable and cost-effective energy storage systems, and (b) to adopt an energy storage system procurement target by October 1, 2014, if determined to be appropriate, to be achieved by the utility by December 31, 2016, and a 2nd target to be achieved by December 31, 2021.

Energy storage (ES) has been advocated as an effective means for addressing the growing operational problems of integrating intermittent renewable resources, as well as contributing to other applications on and off the grid. In general, ES is a set of technologies capable of storing previously generated electric energy and releasing that energy at a later time. Currently, the commercially available ES technologies (or soon to be available technologies) consist of pumped hydro generation, compressed air systems, batteries, and thermal ES systems.

On February 17, 2012, as per the statute, the Riverside Board of Public Utilities opened a proceeding to investigate the various energy storage technologies available and determine if Riverside should adopt energy storage procurement targets. Riverside Public Utilities finished its investigation of energy storage pricing and benefits in September 2014 and concluded that the current pricing of all commercially available technology outweighs the benefits that it might provide to our electrical system.

Riverside intends to update this assessment annually, in order to determine if and when any energy storage procurement targets should be set.

5.1.6 AB 2021 -- Energy Efficiency (EE) & Demand Side Management (DSM)

AB 2021 was approved by Governor Schwarzenegger on September 29, 2006. The purpose of this bill was to promote conservation and energy efficiency in California. This law mandates that all California utilities aggressively invest in all achievable cost effective EE and DSM programs in their service territories. The goal of these efforts is to reduce forecasted electricity demand by 10 percent over 10 years, offsetting the need to build new power plants.

AB 2021 requires the Energy Commission to develop a statewide estimate of all potentially achievable cost-effective electricity and natural gas efficiency savings and establish statewide annual targets for energy efficiency savings and demand reduction programs. POU's specifically are required to identify achievable, cost-effective efficiency potential every 3 years and establish annual targets based on that potential for a 10-year period. The costs for these efforts are funded through a 2.85% energy sales charge that is applied to all retail customers in the POU's service territory. All POU's are required to report annually on their sources of funding, cost-effectiveness, and verified energy efficiency and demand reduction results from independent evaluations.

Riverside has been funding the required amount of EE and DSM programs via the sales charge since AB 2021 became law. However, an open question remains with respect to which EE and/or DSM programs are most cost-effective in an integrated resource sense. This specific topic is explored in greater detail in Chapter 6.

5.1.7 Distributed Generation (DG) Mandate

In 2012, Governor Jerry Brown issued an executive directive to develop 12,000 MW of distributed generation resources within the next 10 years. The primary goal of this mandate is to better facilitate state transmission/distribution planning with respect to the integration of renewable resources.

The CAISO is spending a considerable amount of effort via new market initiatives to deal with this and other ancillary mandates that will impact the CAISO grid operation. DG-type mandates relate to primarily the demand side of the supply and demand picture and therefore are much more de-centralized in nature. From a decision making standpoint, the complexity of such mandates are much more challenging than analyzing purely supply side solutions. Additionally, there are many more stakeholder groups involved in these debates, making a reasoned decision making process without political interference that much more challenging. It remains to be seen whether these discrete/ancillary mandates can be integrated in a holistic and cost effective manner without disproportionally burdening the ratepayers in general and selected groups of stakeholders in particular.

Currently, Riverside is working towards fulfilling at least some of its DG mandate via the development of utility owned solar PV installations within the city limits. The largest of these is our 7

MW solar PV project on the Tequesquite Landfill site (e.g., our "Tequesquite" resource, see Table 3.1). However, RPU is also currently exploring opportunities to build smaller assets throughout its service territory.

5.2 CAISO Market Initiatives

Given the multitude of ongoing mandates that impact CAISO market operations, CAISO has instituted market initiatives to address them. These market initiatives are in various stages of development and implementation and have the involvement of large number of stakeholder groups. The primary/overarching themes/issues in these market initiatives are as follow:

- Create efficient market paradigms to solve grid reliability issues
- Appropriate cost allocation equitably and fairly
- Maintain regulatory jurisdiction in the decision making process

The most important CAISO market initiatives now under way are described in more detail below.

5.2.1 Energy Imbalance Market (EIM) Initiative

This market initiative started as an attempt within the Western Electricity Coordinating Council (WECC) to improve regional diversity in the operation and utilization of power resources to integrate an increasing amount of intermittent resources throughout the West. In 2012, the CPUC requested that the CAISO develop a market paradigm that could improve on the market efficiency while taking into account the regional diversity in load and resources. In 2013, the CAISO and PacifiCorp signed a Memorandum of Understanding (MOU) to develop such a market paradigm for the West by leveraging the current CAISO centralized market structure in managing the real time imbalance requirements throughout the West. The thrust/concept is by managing diverse resource portfolio across a larger grid footprint, economic efficiency can be captured while enhancing reliability.

The CAISO has filed the MOU with the FERC and is currently refining the market implementation design. The CAISO implemented this new EIM in the fall of 2014, in conjunction with the launch of the CAISO 15-minute market (described below). However, major EIM cost allocation and real time balancing issues still need to be adequately resolved, if this EIM initiative is to be successful.

5.2.2 FERC Order 764 – 15-Minute Market Initiative

FERC issued a rulemaking in late 2011 mandating the regional transmission organizations to consider and implement market structures to accommodate the increasing amount of intermittent resources that are anticipated to come on line in the foreseeable future. FERC believes that these resources can be more effectively integrated by the scheduling of electricity in sub-hour intervals with more precise real time forecasts of intermittent resources (in order to match loads and resources more precisely).

The CAISO responded to this FERC directive with its 15-minute market initiative -- with the goal of scheduling and financially settling all transactions through the CAISO on a 15-minute interval basis.

Previously, the CAISO had settled import transactions on an hourly basis and intermittent resources within the CAISO grid on a monthly average basis under the Participant Intermittent Resource Program (PIRP). The 15-minute market was launched in the fall of 2014; this new market is currently having a significant impact on import power prices and PIRP resources (predominantly the clearing prices of wind and solar resources). Additionally, the implementation of CAISO 15-minute market has added additional complexity and workload to Riverside's market scheduling and settlement functions.

5.2.3 CAISO Flexible Resource Adequacy and Enhanced Must Offer Obligation (FRAC/MOO) Initiative

Given the increasing amount of intermittent resources that are anticipated to come online in the foreseeable future, CAISO is anticipating significant changes in operational needs within its system. Historically, utilities and the CAISO have dealt with supply uncertainty within the generation fleet by imposing a reserve margin or resource adequacy (RA) margin; normally 15% additional capacity above the monthly peak demand of each load serving entity. This RA margin is designed to take into account forced generation outage events and weather driven load swings. However, this traditional approach will no longer be sufficient in the presence of large amounts of intermittent resources, given their high variability and aggregated impact on daily operations.

Recently, the CAISO illustrated the changing operational needs within its system by plotting the expected normal system hourly load minus the amount of intermittent generation (i.e., the infamous "duck" graph, see Figure 5.2.1). As shown in this figure, commencing 2015 when significant solar PV generation will come online, the expected system-wide ramping requirement in the evening hours will significantly increase. This increase results from the combined effect of increasing evening loads with the rapid falloff solar power generation when sun goes down, presenting significant challenges to balance load and resources during a short timeframe (3-hour timeframe). The CAISO asserts that it needs significant amount of flexible capacity that can be ramped up and down fairly quickly to assist in managing this supply and demand balance. Also, such flexible capacity must be made available to the CAISO to meet these ramping needs as opposed to utilities using their own resources to meet their individual load requirements.

CAISO originally intended to require all utilities within its footprint to provide such capacity based on load ratio share of utility's individual peak to the system peak load. The California POU's have challenged this simplified approach, instead arguing that the amount and type of intermittent resources that each utility contracts for should also be factored into flexible capacity requirement. At this time the POU's appear to have made some progress on this issue, i.e., CAISO now recognizes that the contributions to its flexibility capacity needs are not uniform across the utilities and allocation of the obligation should not be uniform as well.

The FRAC/MOO initiative is continuing with a preliminary trial market implementation slated for calendar year 2015.

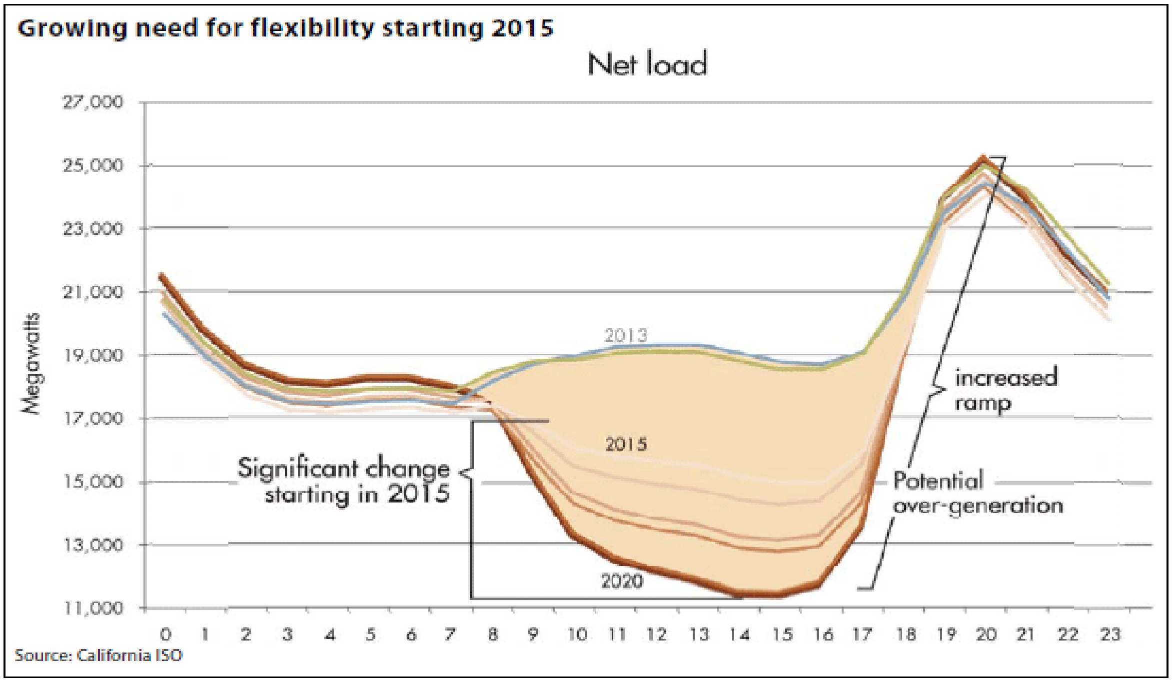


Figure 5.2.1. CAISO projected operational needs assessment through 2020, due to increasing intermittent generation within the ISO system.

5.2.4 CAISO/CPUC Joint Reliability Framework

Closely related to the FRAC/MOO market initiative is the issue of how the CAISO can incite the development of future flexible capacity to meet CAISO reliability needs, such as increased ramping and the need to manage over-generation. The CAISO's preferred approach is the centralized capacity market approach, whereby CAISO determines its operational needs a priori and then runs a centralized capacity market to procure capacity resources for the long term. CAISO's preference for a capacity market is founded on the fact that FERC has sanctioned such centralized capacity markets in the ISOs in the Eastern US, along with the perceived efficiency gains of a centralized procurement paradigm.

However, the CPUC and POU's are diametrically opposed to the CAISO's preference, because under such a paradigm the CPUC and POU's must cede the jurisdiction of procurement decisions to FERC. As a compromise, the CPUC and CAISO are currently working on a market paradigm called the "Joint Reliability Framework" that accomplish the flexible resource procurement through the local regulatory authorities (CPUC for the IOU's and City Councils for the POU's), while introducing a voluntary centralized capacity market as the backstop. The preliminary details of this hybrid market structure have just recently emerged and considerable debate and development will still need to take place before implementation of this new capacity paradigm.

In the development of this long term hybrid capacity market structure, there are two important issues that will impact Riverside. First is the treatment of imported flexible capacity; for example, will such capacity be treated on the equal footing as in-state flexible capacity? Second, will proper incentives be provided to the utilities to procure non-intermittent renewable resources? For example, will geothermal resources receive proper capacity credit for helping achieve the state RPS goals, given that these resources impose less operational requirements for the CAISO to manage? The resolution of these issues will have significant bearing to Riverside, given our current resources and future resource acquisition plans.

More generally, it is very important to Riverside that we receive our full allocation of RA credit for our re-contracted CalEnergy geothermal assets (beginning in 2016). By June 2020, 86 MW of new base-load geothermal energy will be incorporated into our resource stack; the associated system RA credit we could receive for this resource will be worth millions of dollars per year. Note that Riverside's long-term RA needs and projected costs under various intertie allocation scenarios (and new generation development assumptions) are discussed in greater detail in Chapter 9, respectively.

5.2.5 CAISO Market Initiatives Related to Transmission Planning

Given the RPS mandates, the CAISO transmission planning has undergone and continues to undergo significant changes. The traditional transmission planning based solely on reliability needs has evolved into an enhanced effort to build additional transmission to access new renewable resources. The CAISO has revamped its transmission planning process to that effect by approving high voltage transmission projects funded by all users of the transmission system for renewable projects, regardless of whether a particular utility has any stake in the area transmission projects are built. In essence, the CAISO is socializing the cost of transmission built for policy reasons across its footprint. The cost for CAISO transmission is anticipated to increase from the current $9/MWh to more than double in calendar year 2020 if all policy driven transmission projects are ultimately built. However, significant concerns remain as to whether the associated renewable projects will all come to fruition. If not, then there could be significant stranded transmission costs that all of the CAISO transmission users will be paying for many decades to come.

At this time, the POU community is alone in raising the transmission stranded cost concerns. So far, there is no traction from policymakers (legislators and regulators) to address this concern.

On a regional level, FERC instituted FERC Order 1000 rulemaking process to address the transmission investment issue. FERC Order 1000 is designed to foster a regional transmission planning process and is primarily focused on the fair cost allocation of transmission investments that are driven by policy reasons (e.g., state RPS mandates that require out-of-state transmission to be built and who should pay for them). The CAISO made a compliance filing with FERC that essentially advocates that the cost and benefits of transmission built on regional level should be allocated in proportion to the cost incurred and benefit derived by each transmission system. It remains to be seen whether FERC Order 1000 paradigm will have any practical applicability throughout the West.

6. Energy Efficiency (EE) and Demand Side Management (DSM) Programs

6.1 Program Background

RPU is committed to making Riverside a greener place to live by supporting renewable energy, responsible purchasing and design, and sustainable living practices. In 2001, the city began using LEDs in all city traffic lights, cutting energy costs and making the signals more visible. This was also the year RPU installed solar panels at its Utilities Operation Center. An important portion of RPU's future resource strategy is to cost effectively expand our Energy Efficiency (EE) and Demand Side Management (DSM) programs.

Energy Efficiency programs are intended to reduce the total amount of energy used by customers. Examples of EE programs include the shade tree rebate program that encourage the planting of shade trees that help reduce cooling energy use, the replacement of incandescent light bulbs with compact fluorescent bulbs, as well as replacement of air conditioner and refrigerator units with more energy efficient models. Likewise, another EE example is encouraging industrial customers to use more efficient motors to reduce total energy use. In general, EE improvements result in our customers using both less energy and less peak demand.

Demand Side Management programs, in contrast to strict Energy Efficiency measures, do not necessarily reduce the total amount of energy used by customers but instead change the timing of energy usage. Typically, DSM programs move energy use from high production cost periods to lower cost periods. DSM programs help to counter or minimize peak demand growth and thereby lessen the need to build more physical generation assets to meet Resource Adequacy requirements. Examples of DSM programs include our residential pool pump program that encourage customers to operate their pool pumps during off-peak periods, thermal energy storage systems that shift commercial/industrial air conditioning loads to off-peak periods, and time-of-use (TOU) rate schedules that encourage customers to favor off-peak energy consumption.

In general, Energy Efficiency programs tend to save customers money by reducing the total amount of energy purchase, while Demand Side Management programs tend to reduce overall utility costs by avoiding or reducing energy usage during peak hours. In addition to the aforementioned benefits, EE and DSM programs also help to

- Defer our need to build physical generation assets
- Reduce our RPS compliance costs
- Reduce our environmental footprint, including lowering our GHG emissions
- Create a potential for local job creation opportunities

Notwithstanding these positive benefits, all EE and most DSM programs also impose costs on a utility, specifically in the area of "unmet revenue streams". Obviously, it is important to properly estimate these costs, in order to conduct an accurate cost/benefit analysis of each program.

6.2 RPU EE/DSM Savings

In 2012 RPU's energy efficiency programs exceeded established goals, garnered national attention, and assisted customers in saving on their utility bills by reducing energy consumption. In fiscal year 2011/2012, RPU achieved a calculated net peak savings of 5.487 MW and a net annual savings of 21,244 MWh. RPU ranked 5th among California's top fifteen public utilities with respect to calculated net annual MWh savings.

RPU is committed to meeting the annual energy efficiency and conservation goals established through Assembly Bill 2021 (AB 2021) for energy and demand reduction. The revised energy reduction goal of 215,319 MWh over the next ten years (2014 - 2023) represents 1% of the revised load forecast completed in 2010. RPU intends to provide the required financial budget to meet these targets and will continue to develop new cost-effective programs that yield energy savings necessary to achieve the goals set forth by AB 2021.

6.3 RPU Current EE/DSM Programs

The Public Benefits Division currently reviews and administers our EE/DSM programs and collects data to assess the energy savings and cost effectiveness of all energy efficiency technologies that qualify for RPU rebates. The successful residential Whole House Rebate Program has now been fully transitioned to a PBC (Public Benefit funds) funded program now that American Recovery and Reinvestment Act funding has been exhausted. RPU residential programs continue to experience wide support and participation by customers.

Below is a list of major residential and commercial EE and DSM programs currently offered by RPU. Additionally, Table 6.3.1 presents a summary of kW and kWh savings for our various Energy Efficiency programs during fiscal year 2011/2012 (FY11/12).

Residential EE Programs:

- **Tree Power - Shade Tree Rebate Program**
  - Riverside Public Utilities electric customers can earn rebates throughout the year when they plant select shade trees around their home. Since the start of the program, RPU has given away more than 125,000 trees.
- **Refrigerator Recycling Program**
  - Refrigerator Recycling is a free public benefit service that offers residential electric customers the opportunity to recycle older, operating inefficient refrigerators and standalone freezers. These units are transported to a recycling facility for dismantling and processing, making the program easy and convenient for our customers.

- **Pool Pump Motor Rebate Program**
  - This program offers Riverside Public Utilities electric customers, who have in-ground pools and spas, the opportunity to receive rebates back on the purchase and installation of new, Energy Efficient Pool Pumps (EEPPs).
- **Energy Star Rebates**
  - Energy Star is a partnership between the U.S. Department of Energy, the Environmental Protection Agency, product manufacturers, local utilities and retailers that promote efficient products and educate consumers about the benefits of energy efficiency. Riverside Public Utilities has been an Energy Star partner since 1999.
- **Residential Air Conditioning Rebate Program**
  - This public benefit program offers rebates to residential electric customers when they purchase and install new high energy-efficient air conditioning systems or heat pumps for the first time. This program also covers replacing existing system with a new, high energy-efficient system.
- **Weatherization Rebate**
  - The Weatherization Rebate Program is a whole-house approach to improving the energy efficiency of residential homes in Riverside Public Utilities' electric service territory. The program is open to all RPU residential electric customers. Rebates are available for attic and exterior wall insulation, whole house fans, attic fans (solar and electric), duct insulation and sealing, window film, and Cool Roof coatings or products.

Commercial EE Programs:

- **Energy-Efficient Exit Signs**
  - RPU offers incentives for replacing older, inefficient exit sign lighting with the most energy efficient fixtures available. Qualified exit sign lighting must be LED or Photo Luminescent Exit signs that replace incandescent or compact fluorescent lamps (CFLs).
- **Weatherization Rebate**
  - RPU's commercial Weatherization Rebate Program is an innovative approach to improving the energy efficiency of Riverside's businesses. This program is open to all RPU commercial electric customers. Rebates are available for attic and exterior wall insulation, whole building fans, attic fans (solar and electric), window film, and Cool Roof coatings or products.

- **Personal Computer Power Management Rebate**
  - In keeping with its goal of attracting and fostering business in the City of Riverside, RPU has joined with Smart Riverside to develop the Personal Computer Power Management Rebate Program. Under the program, businesses located in the City of Riverside can receive energy efficiency rebates for implementing PC power management software on personal computers. PC Power Management software is an energy saving solution for desktop computers.
- **Air Conditioning Incentives**
  - Air conditioning equipment can be the largest utility expense for a business. Older systems provide inefficient heating and cooling while consuming excessive energy. RPU offers Air Conditioning Incentives for businesses that help offset the costs of replacing inefficient Air Conditioning system with newer efficient system.
- **Energy Efficiency Lighting Incentive**
  - Riverside Public Utilities offers our commercial customers incentives when they replace older, inefficient lighting with the most energy-efficient fixtures available. Recently, this program was expanded to include day lighting and occupancy sensors, along with solar tubes and sky lighting.
- **Energy Star-Rated Product Incentives**
  - Energy Star-rated products can save 20-30% on energy costs. Commercial businesses can apply for RPU's Energy Star-rated Product Incentive rebates when they purchase these appliances for business use.
- **Premium Motor Incentives**
  - RPU offers businesses incentives to help offset the costs of new, more efficient premium motors. For manufacturers using older motors, RPU offers rebates towards the purchase of electric motors with the highest energy efficiency output needed for each application.
- **Pool & Spa Pump Incentives**
  - For business customers with in-ground swimming pools or spas as part of their facility, RPU offers rebates for replacing old, inefficient pumps with new, high-efficiency equipment. High-efficiency pumps can save up to 90% in energy costs via the use of new variable speed and variable flow pumping technology.

- **Energy & Water Technical Assistance Services**
    - In addition to the above mentioned rebates and incentives, Riverside Public Utilities offers tools that business customers can use to manage their energy and water consumption. Each of these services may be customized to suit different needs.

DSM Programs:

- **Residential Pool Pump Billing Credit Rebate Program**
    - RPU offers our residential electricity customers a $5 credit toward their monthly electricity bill for every month they shift their pool pump usage to off-peak hours. Using pool pumps when energy demand is low directly lowers our peak energy demand and reduces the stress on Riverside's electrical grid.
- **Commercial Thermal Energy Storage**
    - RPU offers significant rebates to commercial and industrial customers who install a thermal energy storage system to shift their cooling load to off-peak hours.
- **Demand Response/Smart Grid**
    - In addition to the Power Partners voluntary load curtailment program implementing 14 MW of voluntary load shed capability for the summer of 2012, RPU continues to implement a commercial time-of-use (TOU) rate to encourage off-peak energy use by its large customers. RPU is also currently evaluating other demand response (DR) measures such as Smart Grid technology and voluntary DR agreements for reliability contingencies.

Table 6.3.1. Summary of RPU EE program savings for FY11/12.

Riverside		Resource Savings Summary						Cost Summary		
Program Sector (Used in CEC Report)	Category	Units Installed	Net Demand Savings (kW)	Net Peak kW Savings	Net Annual kWh Savings	Net Lifecycle kWh savings	Net Lifecycle GHG Reductions (Tons)	Utility Incentives Cost ($)	Utility Mktg, EM&V, and Admin Cost ($)	Total Utility Cost ($)
Appliances	Res Clothes Washers	1,338	181	181	70,513	846,151	504	$100,350	$2,151	$102,501
HVAC	Res Cooling	15,361	732	749	2,279,922	67,231,719	44,326	$496,592	$285,117	$781,709
Appliances	Res Dishwashers	748	63	63	18,371	202,080	120	$37,400	$485	$37,885
Consumer Electronics	Res Electronics									
HVAC	Res Heating									
Lighting	Res Lighting	18,697	1,527	210	1,320,462	6,651,098	3,773	$46,020	$14,097	$60,117
Pool Pump	Res Pool Pump	144	9	9	36,979	369,792	210	$28,800	$882	$29,682
Refrigeration	Res Refrigeration	3,745	266	266	1,251,193	7,849,021	4,430	$555,354	$17,891	$573,245
HVAC	Res Shell	283	52	52	71,543	1,399,993	904	$36,900	$5,972	$42,872
Water Heating	Res Water Heating									
Comprehensive	Res Comprehensive	789			1,056,909	12,673,022	7,154	$824,050	$29,427	$853,478
Process	Non-Res Cooking									
HVAC	Non-Res Cooling	2,230	289	315	634,774	12,098,338	7,649	$142,246	$37,575	$179,820
HVAC	Non-Res Heating									
Lighting	Non-Res Lighting	8,165	1,560	1,560	7,801,850	78,018,500	46,208	$690,868	$206,659	$897,526
Process	Non-Res Motors	4			267	1,068	1	$140	$2	$142
Process	Non-Res Pumps									
Refrigeration	Non-Res Refrigeration	11	7	7	170,280	1,021,680	569	$45,523	$2,224	$47,747
HVAC	Non-Res Shell									
Process	Non Res Process									
Comprehensive	Non Res Comprehensive	11,551	2,074	2,074	6,050,786	53,741,869	30,659	$384,681	$127,531	$512,212
Other	Other	143,373			480,136	6,189,605	3,796	$356	$19,396	$19,752
SubTotal		206,439	6,762	5,487	21,243,985	248,293,936	150,302	$3,389,280	$749,409	$4,138,689
T&D	T&D									
Total		206,439	6,762	5,487	21,243,985	248,293,936	150,302	$3,389,280	$749,409	$4,138,689

EE Program Portfolio	TRC Test	2.99
	PAC Test	7.47

6.4 Cost/Benefit Principles of EE and DSM Programs

Every EE or DSM program carries both costs and benefits to both the customer and utility. In theory, by examining these financial impacts, RPU should be able to identify the optimal mix of EE and DSM programs that maximize the benefits to each customer and minimizes the financial impacts on RPU.

More specifically, each type of EE/DSM program will affect the participating customer, the non-participating customers and the utility. Generally, a customer that participates in one or more of these programs reduces their costs and thus their payments to the utility. At the same time, the utility will typically reduce both its power supply costs and distribution system maintenance costs. However, if the utility's reduction in costs is less than the customer's reduction in costs, then the utility will experience a "net unmet revenue effect". When this occurs, the utility must in turn raise its rates to recover this unmet revenue stream. Hence, even though the utility's costs decline as a result of the specific EE/DSM program, the utility's revenues decline more and the utility must raise its rates, resulting in an effective rate increase for all non-participating customers.

Unfortunately, some EE programs tend to raise costs for non-participating customers, via the net unmet revenue effect. However, many DSM programs do not generally have the same negative impact on non-participating customers, since these programs can often reduce utility costs enough to nearly or fully offset the decline in utility revenue. The most successful programs can even allow the utility to reduce costs for all customers.

The underlying premise of DSM programs is that they encourage customers to switch energy use from a higher cost period (e.g., 1 pm to 8 pm) to a lower cost period (11 pm to 7 am, or weekends). The cost of producing energy to meet customer requirements varies during the day and throughout the week. During the low load hours, energy from either RPU's inexpensive generation resources or low cost market power can be used to meet customer demands. However, as the load increases, either more expensive generation resources or more expensive market power must be used to meet the increase in customer demand. Thus, to the extent customers can reduce their energy consumption during the high cost periods and use as much or more energy during the low cost periods, the utility's total power costs decline. Additionally, if such load shifting occurs within stressed areas of the distribution system, then additional system maintenance expenses can also be avoided or deferred.

6.5 Cost/Benefit Calculations

If a customer chooses to participate in EE/DSM program, their financial savings for each year can be approximated as:

Savings = ((kWh saved) x (retail rate)) + ((Demand Reduction) x (Demand Rate))
+ (Utility Incentives) – (Program Costs)

Note that the "Program Costs" typically need to be expressed as an annual amortized cost for the life expectancy of the equipment in question. For example, a new AC system may have a twenty year life expectancy, while a new CFL may only last seven years, etc. Regardless, if the energy savings plus any utility incentives are greater than program participation costs, the customer is said to have a financial incentive to participate in the EE/DSM program.

For most non-demand metered customers, primarily those in the residential and small commercial classes, the financial success of a program is primarily due to reducing total energy use. Hence, programs that are most attractive to residential customers are those that target high energy use applications, such as refrigeration, air conditioning (and electric heating), and lighting. For demand metered customers, the program benefits are often dominated by demand charge savings. Thus, programs that help reduce peak demand charges are often favored by TOU customers.

When a utility chooses to offer an EE/DSM program, the resulting program Impact can be approximated as:

Impact = (Avoided Power Supply costs) + (Avoided Capacity Expansion costs)
+ (Avoided or Deferred Distribution system costs)
+ (Avoided Environmental compliance costs) – (Utility Incentives)
– (Unmet retail revenues) – (Unmet transmission revenues)

Although the above equation appears straight-forward, in practice it can be very difficult to accurately calculate. In the textbook "Electric Utility Resource Planning" (CRC Press, 2012), author Steven Sim identifies at least sixteen utility avoided cost impacts that should be considered in order to fully assess the impact of any EE/DSM option (particularly when comparing these to supply side options). An additional complication arises when one considers what type of power supply and capacity expansion costs to consider. For example, as a participating member in the CAISO, RPU does not necessarily have to build new generation in order to supply our unmet load needs. Instead, the utility could simply purchase more ISO system power and forward procure the required system Resource Adequacy (RA) capacity via bilateral contracts. Hence, this raises the obvious question: should we use the CAISO market or new internal generation costs to estimate our avoided power supply and/or capacity expansion cost(s)?

It is beyond the scope of this IRP to fully quantify both the Savings and Impact costs of each EE and/or DSM program offered by RPU. (For a current update on EE program energy saving performance metrics within the RPU service territory, the interested reader should consult RPU's latest SB1037 status report, and/or the combined CMUA/NCPA/SCPPA 2013 Energy Efficiency Status Report.) However, it is worthwhile to present a few simplified examples of how avoided power supply costs, avoided capacity expansion costs and unmet retail revenues can be at least initially estimated. These examples begin to help clarify the types of information that must be brought together to effectively assess different EE/DSM programs.

6.6 Three Examples of Approximate (Partial) Impact Calculations

The following analysis shows the first order, partial impact calculations for one EE and two DSM options that RPU currently supports; specifically (a) the Residential AC rebate program, (b) the Commercial thermal energy storage (TES) program, and (c) the Residential pool pump billing credit rebate program. These represent partial impact calculations only, since neither the avoided distribution system nor environmental compliance costs are numerically quantified. Likewise, the lost transmission revenues are also not considered. Notwithstanding these limitation, the following calculations are still useful for highlighting some of the initial cost differences between these three programs.

In the following calculation examples, we will assume that RPU's avoided power supply and capacity expansion costs can be estimated using avoided CAISO market energy and RA purchases. Table 6.6.1 below shows the avoided CAISO RA costs assumed in these examples; note that these are derived from "blended cost quotes" for both 2014 system and local RA (75% system & 25% local). The associated hourly CAISO market energy prices used in these examples are shown in Tables 6.6.2 and 6.6.3; these prices are stratified by month and time-of-week (week day versus weekend) and normalized for a $5.00/MMBtu natural gas cost. Together, these prices can be used to compute our avoided market energy and capacity costs, once the time dependent energy and capacity reductions are specified for any EE or DSM program. Finally, we will assume that the Unmet Retail Revenues are equal to the first two energy saving components in the customer Saving equation (i.e., energy & capacity amounts saved x rate charged).

Table 6.6.1. Representative 2014 CAISO market RA costs for typical bilateral transactions.

Season	Blended Quote ($/kW-month)	System Quote ($/kW-month)	Local Quote ($/kW-month)
July-September (Q3)	$5.50	$4.00	$10.00
May, June, October	$2.06	$1.50	$3.75
November-April	$0.69	$0.50	$1.25

Example 1: Residential AC rebate program

In this first example, we consider the partial impact effect of a Residential customer replacing their inefficient 10 SEER, 4-ton AC unit with a new, high-efficiency 16 SEER, 4-ton unit. We assume that the average customer runs their AC unit 5 hours per day during HE14-HE18 from May 16 to June 30 and October 1 through October 15, and 9 hours per day during HE12-HE20 from July 1 through September 30. We assume that this pattern remains consistent after replacing the AC unit, and that the typical customer pays $0.175/kWh for the consumed electricity (the approximate average value of our current Tier 2 and Tier 3 Residential rates).

The pertinent customer savings calculations and utility avoided cost calculations for this first example are summarized below:

- Old unit: 10 SEER; New unit: 16 SEER
- 1 ton cooling = 12,000 Btu/h → 4-ton unit = 48,000 Btu/h
- Average power usage = (Btu/h) / SEER (Btu/Wh)
    - Old unit = 4.8 kw/h
    - New unit = 3.0 kW/h
- New unit reduces peak demand by 1.8 kW and energy usage by 1.8 kWh/h
- Unit runs for 5 hours/day for 60 days, 9 hours/day for 92 days (from usage assumption)
- Annual energy savings = 1.8 kWh/h x [5x60 + 9x92] hours = 2,030.4 kWh
- → Customer cost savings = Gross unmet retail revenues = 2,030.4 kWh x $0.175/kWh = $355.32
- Avoided RPU energy costs (from Tables 6.6.2 and 6.6.3)
    - May, June, Oct: $0.0497/kWh x 1.8 kWh/h x 300 hours = $26.84
    - July-Sept: $0.0580/kWh x 1.8 kWh/h x 828 hours = $86.44
- Avoided RPU capacity (RA) costs (from Table 6.6.1)
    - May, June, Oct: 1.8 kW x $2.06/kW-month x 3 months = $11.12
    - July-Sept: 1.8 kW x $5.50/kW-month x 3 months = $29.70
- → Annual avoided RPU energy & capacity costs: $154.10
- Partial net unmet revenue effect (normalized) = ($154.10 - $355.32) / 1.8 kW = ($111.79/kW)

Thus, before we consider the $150/ton utility rebate offered for this EE program, we see that the utility can expect, on average, to experience a ($111.79) partial net annual unmet revenue effect per kW of capacity savings for each customer that takes advantage of this program. Therefore, the utility must either avoid or defer an additional $112 per kW in distribution system and/or environmental compliance costs on an annual basis, in order to offset this annual unmet revenue effect.

Example 2: Commercial TES program

For the second example, consider the partial impact effect of large Commercial customer installing a 143 ton Chiller system to offset 100kW/h of on-peak energy usage. Assume that the Chiller system can discharge up to 6 hours a day during the summer season, must recharge for 9 hours each evening, and has a 0.7 efficiency ratio (e.g., it must consume 10 kW of off-peak Chiller energy to displace 7 kW of on-peak AC energy). We further assume that it has the following weekday operational pattern: in June it offsets 100 kW/h during HE16-HE18 and uses 47.6 kW/h to recharge during HE24-HE08; for July through September it offsets 100 kW/h during HE13-HE18 and uses 95.2 kW/h during HE24-HE08. Finally, we assume that the Commercial customer is under our TOU rate and that they receive the TES discounted off-peak energy rate ($0.0610) for the HE24-HE08 time period.

The pertinent customer savings calculations and utility avoided cost calculations for this second example are summarized below:

- Chiller reduces peak demand by 100 kW
    - June energy patterns (22 days): On-peak energy savings: 300 kWh/day; Off-peak energy consumption: 428.6 kWh
    - July – September energy patterns (66 days): On-peak energy savings: 600 kWh/day; Off-peak energy consumption: 857.2 kWh
- TOU rates: On-peak demand ($6.88/kW), energy ($0.1033); Off-peak demand ($1.31/kW), energy ($0.0610, after TES discount)
- Customer demand cost savings = 100 kW x ($5.57/kW) x 4 months = $2,228.00
- Customer energy cost savings = (300x22 + 600x66) x $0.1033/kWh - (428.6x22 + 857.2x66) x $0.0610/kWh = $4,772.46 - $4,026.27 = $746.19
- → Total Customer savings: $2,974.19
- Avoided RPU energy costs (from Table 6.6.2)
    - June: $0.0560/kWh x 6,600 - $0.0227/kWh x 9,429.2 = $155.56
    - July-Sept: $0.0631/kWh x 39,600 - $0.0301/kWh x 56,575.2 = $795.85
- Avoided RPU capacity (RA) costs (from Table 6.6.1)
    - 100 kW x ($2.06 + (3)x$5.50)/kW-month = $1,856.00
- → Annual avoided RPU energy & capacity costs: $2807.41
- Partial net unmet revenue effect (normalized) = ($2,807.41 - $2,974.19) / 100 kW = ($1.67/kW)

Note that in this DSM example, RPU's partial unmet revenue effect is very minimal. As opposed to the Residential AC example; this Commercial DSM example almost pays for itself (before we consider any additional distribution or environmental compliance savings, or program incentive rebates and administration costs).

Example 3: Residential Pool Pump rebate program

In this third and final example, we consider the partial impact effect of a Residential customer choosing to participate in the Pool Pump billing credit rebate program. We assume that the average customer runs their pool pump for 4 hours per day during HE13-HE16 from November 1 through April 30, and 8 hours per day during HE11-HE18 from May 1 through October 31. We will also assume that when the customer signed up for this program, they shift the timing of their pool pump from the day to the middle of the night (HE03-HE06 from November 1 through April 30; HE01-HE08 from May 1 through October 31). Finally, we assume that the typical Residential customer used an 8 Amp, 220 Volt pump.

Note that since nearly all RPU Residential customers are currently billed on the Residential Tier rate, there is no financial incentive for the customer to participate in this DSM program, other than the utility incentive payment. Hence, there will be no change in the customer's energy usage or charges, except for the monthly RPU bill credit. In contrast, the utility will benefit from both avoided energy and capacity costs; the pertinent utility avoided cost calculations are summarized below:

- 8 Amp, 220 Volt pump → 1.76 kW/h energy (and demand) usage
- Avoided RPU energy costs (from Tables 6.6.2 and 6.6.3)
    - Nov-Apr: $(0.0397-0.0299)/kWh x 4 h/day x 181 days x 1.76 kW/h = $12.49
    - May-Oct: $(0.0524-0.0281)/kWh x 8 h/day x 184 days x 1.76 kW/h = $62.95
- Avoided RPU capacity (RA) costs (from Table 6.6.1)
    - Nov-Apr: 1.76 kW x $0.69/kW-month x 6 months = $7.29
    - July-Sept: 1.76 kW x ($5.50/kW-month) x 3 months x ($2.06/kW-month) x 3 months = $39.92
- → Annual avoided RPU energy & capacity costs: $19.78 (winter) + $102.87 (summer) = $122.65
- Avoided costs (normalized) = $69.69/kW annual ($11.24/kW winter; $58.45/kW summer)

It is worthwhile to note that RPU currently offers a flat $5/month ($60/year) bill credit for any Residential customer who participates in the DSM pool pump program. However, the preceding calculations suggest that RPU should actually save more money than it distributes (in the form of a credit rebate) on any customer with pump equipment that draws more than 1 kW per hour. It should also be noted that the bulk of the savings impact for the utility occurs during the summer months; i.e., customer participation in this DSM program is definitely most beneficial during the summer months.

Table 6.6.2. Hourly by month CAISO SP15 energy costs ($/kWh) for weekdays (Mon-Fri).

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
01	$0.0299	$0.0275	$0.0289	$0.0288	$0.0256	$0.0244	$0.0284	$0.0347	$0.0366	$0.0360	$0.0359	$0.0343
02	$0.0268	$0.0245	$0.0270	$0.0274	$0.0236	$0.0215	$0.0248	$0.0305	$0.0326	$0.0326	$0.0316	$0.0308
03	$0.0249	$0.0249	$0.0276	$0.0274	$0.0220	$0.0187	$0.0210	$0.0264	$0.0294	$0.0300	$0.0305	$0.0283
04	$0.0247	$0.0249	$0.0274	$0.0274	$0.0228	$0.0193	$0.0203	$0.0242	$0.0272	$0.0289	$0.0298	$0.0277
05	$0.0285	$0.0271	$0.0299	$0.0292	$0.0227	$0.0183	$0.0198	$0.0255	$0.0299	$0.0322	$0.0323	$0.0318
06	$0.0358	$0.0348	$0.0338	$0.0310	$0.0245	$0.0200	$0.0221	$0.0302	$0.0371	$0.0387	$0.0405	$0.0387
07	$0.0420	$0.0436	$0.0430	$0.0377	$0.0288	$0.0228	$0.0235	$0.0308	$0.0396	$0.0433	$0.0436	$0.0421
08	$0.0448	$0.0488	$0.0512	$0.0452	$0.0359	$0.0310	$0.0316	$0.0358	$0.0416	$0.0467	$0.0475	$0.0452
09	$0.0434	$0.0459	$0.0483	$0.0450	$0.0378	$0.0337	$0.0351	$0.0397	$0.0433	$0.0453	$0.0461	$0.0446
10	$0.0432	$0.0444	$0.0465	$0.0438	$0.0390	$0.0374	$0.0395	$0.0428	$0.0447	$0.0464	$0.0459	$0.0446
11	$0.0432	$0.0444	$0.0486	$0.0464	$0.0422	$0.0417	$0.0436	$0.0454	$0.0471	$0.0498	$0.0465	$0.0446
12	$0.0416	$0.0431	$0.0480	$0.0468	$0.0437	$0.0446	$0.0473	$0.0490	$0.0500	$0.0515	$0.0456	$0.0430
13	$0.0397	$0.0410	$0.0457	$0.0454	$0.0439	$0.0471	$0.0513	$0.0530	$0.0523	$0.0513	$0.0439	$0.0411
14	$0.0386	$0.0401	$0.0454	$0.0449	$0.0436	$0.0497	$0.0575	$0.0593	$0.0555	$0.0521	$0.0439	$0.0407
15	$0.0374	$0.0387	$0.0432	$0.0430	$0.0444	$0.0552	$0.0659	$0.0666	$0.0602	$0.0537	$0.0428	$0.0391
16	$0.0373	$0.0383	$0.0424	$0.0422	$0.0449	$0.0595	$0.0747	$0.0766	$0.0670	$0.0559	$0.0427	$0.0390
17	$0.0402	$0.0393	$0.0396	$0.0390	$0.0429	$0.0583	$0.0739	$0.0760	$0.0659	$0.0542	$0.0460	$0.0432
18	$0.0521	$0.0478	$0.0405	$0.0367	$0.0391	$0.0500	$0.0615	$0.0626	$0.0557	$0.0501	$0.0582	$0.0582
19	$0.0561	$0.0581	$0.0477	$0.0363	$0.0353	$0.0451	$0.0542	$0.0541	$0.0528	$0.0545	$0.0617	$0.0578
20	$0.0502	$0.0519	$0.0556	$0.0481	$0.0400	$0.0407	$0.0462	$0.0507	$0.0540	$0.0586	$0.0540	$0.0517
21	$0.0453	$0.0457	$0.0513	$0.0546	$0.0511	$0.0468	$0.0465	$0.0496	$0.0520	$0.0522	$0.0497	$0.0479
22	$0.0416	$0.0426	$0.0468	$0.0463	$0.0430	$0.0425	$0.0439	$0.0449	$0.0460	$0.0480	$0.0457	$0.0436
23	$0.0387	$0.0383	$0.0416	$0.0392	$0.0350	$0.0362	$0.0403	$0.0421	$0.0422	$0.0450	$0.0442	$0.0424
24	$0.0342	$0.0326	$0.0342	$0.0315	$0.0274	$0.0285	$0.0340	$0.0379	$0.0379	$0.0392	$0.0392	$0.0382

Table 6.6.3. Hourly by month CAISO SP15 energy costs ($/kWh) for weekends (Sat-Sun).

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
01	$0.0319	$0.0293	$0.0307	$0.0306	$0.0272	$0.0260	$0.0302	$0.0367	$0.0389	$0.0383	$0.0382	$0.0367
02	$0.0294	$0.0268	$0.0295	$0.0299	$0.0258	$0.0237	$0.0271	$0.0332	$0.0357	$0.0357	$0.0347	$0.0339
03	$0.0268	$0.0268	$0.0298	$0.0293	$0.0237	$0.0203	$0.0226	$0.0283	$0.0316	$0.0323	$0.0329	$0.0306
04	$0.0263	$0.0266	$0.0293	$0.0290	$0.0242	$0.0207	$0.0216	$0.0256	$0.0290	$0.0309	$0.0318	$0.0296
05	$0.0282	$0.0271	$0.0299	$0.0289	$0.0227	$0.0184	$0.0197	$0.0252	$0.0297	$0.0323	$0.0322	$0.0316
06	$0.0310	$0.0305	$0.0299	$0.0269	$0.0215	$0.0177	$0.0193	$0.0260	$0.0323	$0.0340	$0.0354	$0.0338
07	$0.0314	$0.0327	$0.0324	$0.0277	$0.0215	$0.0173	$0.0176	$0.0228	$0.0296	$0.0325	$0.0327	$0.0316
08	$0.0314	$0.0344	$0.0361	$0.0311	$0.0251	$0.0221	$0.0223	$0.0253	$0.0295	$0.0330	$0.0337	$0.0320
09	$0.0335	$0.0356	$0.0377	$0.0343	$0.0293	$0.0265	$0.0274	$0.0311	$0.0339	$0.0351	$0.0360	$0.0348
10	$0.0361	$0.0372	$0.0390	$0.0361	$0.0327	$0.0318	$0.0335	$0.0364	$0.0380	$0.0390	$0.0387	$0.0375
11	$0.0371	$0.0383	$0.0420	$0.0395	$0.0366	$0.0366	$0.0381	$0.0398	$0.0413	$0.0432	$0.0405	$0.0386
12	$0.0362	$0.0375	$0.0419	$0.0404	$0.0385	$0.0399	$0.0422	$0.0440	$0.0447	$0.0453	$0.0403	$0.0378
13	$0.0342	$0.0353	$0.0395	$0.0389	$0.0386	$0.0420	$0.0461	$0.0479	$0.0469	$0.0448	$0.0385	$0.0358
14	$0.0324	$0.0336	$0.0381	$0.0375	$0.0375	$0.0436	$0.0513	$0.0531	$0.0492	$0.0445	$0.0376	$0.0344
15	$0.0310	$0.0320	$0.0357	$0.0357	$0.0380	$0.0483	$0.0592	$0.0603	$0.0537	$0.0456	$0.0364	$0.0327
16	$0.0310	$0.0315	$0.0350	$0.0352	$0.0387	$0.0526	$0.0686	$0.0709	$0.0607	$0.0477	$0.0364	$0.0326
17	$0.0344	$0.0332	$0.0335	$0.0334	$0.0379	$0.0525	$0.0694	$0.0717	$0.0610	$0.0473	$0.0401	$0.0373
18	$0.0495	$0.0448	$0.0377	$0.0343	$0.0372	$0.0481	$0.0610	$0.0624	$0.0546	$0.0473	$0.0552	$0.0555
19	$0.0554	$0.0570	$0.0465	$0.0352	$0.0345	$0.0444	$0.0547	$0.0547	$0.0530	$0.0538	$0.0611	$0.0573
20	$0.0511	$0.0526	$0.0557	$0.0485	$0.0404	$0.0413	$0.0477	$0.0522	$0.0557	$0.0598	$0.0552	$0.0527
21	$0.0476	$0.0477	$0.0532	$0.0572	$0.0535	$0.0490	$0.0493	$0.0522	$0.0549	$0.0545	$0.0522	$0.0503
22	$0.0424	$0.0433	$0.0474	$0.0472	$0.0438	$0.0432	$0.0450	$0.0460	$0.0472	$0.0489	$0.0467	$0.0445
23	$0.0380	$0.0378	$0.0410	$0.0384	$0.0344	$0.0356	$0.0397	$0.0417	$0.0418	$0.0444	$0.0436	$0.0418
24	$0.0335	$0.0319	$0.0336	$0.0307	$0.0268	$0.0279	$0.0333	$0.0372	$0.0373	$0.0386	$0.0384	$0.0374

6.7 Integration of EE & DSM Options into Supply Side Resource Plans

As shown by the previous three examples, one can compare avoided energy and capacity supply costs to unmet retail revenues (and utility incentive payments) to get an initial assessment of the costs and benefits of an EE or DSM program. This by no means fully quantifies each program, but one can begin to see which programs will be more or less likely to result in a net positive impact for all of the utilitie's customers. For example, our Commercial TES program appears to be more cost effective than our Residential AC program, at least with respect to our partial net unmet revenue effect. Likewise, the assessment of our Residential Pool Pump rebate program suggests that this program may be more cost effective than initially thought. RPU currently has about 2,670 Residential customers participating in this program. Assuming that the average pool pump draws 1.76 kW per hour, signing up an additional 1,000 customers could save RPU an additional 1.76 MW of peak load each year. Indeed, it might be worthwhile to redesign the incentive payments for this DSM program (to encourage a higher summer enrollment), given its apparent cost effectiveness.

More generally, in order to successfully integrate, analyze and compare EE and/or DSM programs with power supply side options, we need to be able to calculate the total program impact equation for each EE or DSM program of interest. RPU currently uses the Ascend PowerSimm PCM software platform, which is a very powerful PCM software analysis tool capable of performing sophisticated hourly generation dispatch under simulated market conditions. This software is fully capable of quantifying our avoided power supply and capacity expansion costs (under either the CAISO market purchase scenario used in the previous examples, or with respect to the avoided costs of a new internal generation asset). This software can also estimate our avoided environmental compliance costs and analyze and quantify various utility incentive programs. However, it is not designed to quantify our unmet retail revenues (for any tier based rate structure), nor is it capable of quantifying our avoided or deferred distribution system costs.

As shown by the previous examples, the correct quantification of our unmet retail revenues is absolutely necessary in order to fully assess the impacts of any EE or DSM program. The Power Resources Planning Unit recommends that such an analysis be undertaken for each EE and DSM program that RPU currently offers. Our Public Benefits Division currently administers our EE and DSM programs and measures our energy efficiency program effectiveness and savings using the CPUC approved E3 Reporting Tool (Energy and Environmental Economics, Inc.). Estimates of the technical, economic and market energy efficiency potential for our utility service area are also produced using Navigant's Energy Efficiency Resource Assessment Model (EERAM). It may be possible to customize either the E3 and/or EERAM tools to accurately estimate our unmet retail revenue streams; we recommend that the Planning Unit coordinate with Public Benefits to investigate this possibility.

Accurate quantification of our avoided or deferred distribution system costs are also very important, especially when considering EE or DSM options for our larger industrial customers. The Energy Delivery Engineering Division is both capable and qualified to perform such calculations. We recommend that Power Planning closely coordinate with the Engineering Division to obtain such cost estimates, in order to better quantify the avoided distribution system costs for such programs.

7 Market Fundamentals

This chapter presents an overview of the forward market data used by the Ascend Portfolio Modeling software platform. RPU obtains forward curve information for the Southern California electricity and natural gas markets from the IntercontinentalExchange (ICE); this forward ICE data has been used to calibrate all the forward curve simulations for our IRP.

7.1 Ascend PowerSimm Curve Developer and Portfolio Manager

RPU primarily relies on the CurveDeveloper component of the Ascend software to manage the forward market price data shown in Table 7.1.1 below. The primary services that CurveDeveloper provides are as follows:

- Automatically harvesting the power and gas forward curves shown in Table 7.1.1 from the IntercontinentalExchange (ICE).
- Scrubbing the harvested forward curves to remove erroneous data points.
- Generating final power and gas forward curves that flow as inputs into the PowerSimm module and other downstream software processes.

Table 7.1.1. Forward market data.

Commodity	Hub	Source
Electricity	SP15 (Peak, Off-Peak)	ICE
Natural gas	Henry Hub	ICE
Natural gas	SoCal Citygate	ICE

The principal output of CurveDeveloper is the generation of monthly-granularity forward price curves (from the raw forward curves) that extend up to twenty five years into the future. If the raw forward curves are not on a monthly-granularity, CurveDeveloper can transform them using arbitrage-free algorithms and seasonal shaping parameters. Likewise, if the raw forward curves do not extend far enough in the future for long term planning, CurveDeveloper is capable of extrapolating them beyond the date range of available data using a user-defined escalation rate. As will be discussed in the following sections, CurveDeveloper performs both of these curve generation processes on the raw ICE forward curves harvested for RPU.

The final power and gas forward curves generated by CurveDeveloper are used by PowerSimm Portfolio Manager to create simulated forward curve data, and they ultimately define the mean levels of the forward curve data in those simulations. Accounting for the volatility of prices and other parameters imbedded in the input forward curves, Portfolio Manager simulates multiple strips of forward curve data that can deviate from the mean, while maintaining an appropriate level of mean reversion to prevent prices from drifting to unreasonable levels. As a result, the simulations of forward prices are realistic and consistent with market expectations present in the input forward curves.

For more detailed information about the Ascend Portfolio Modeling software, please refer to Appendix A.

7.2 SoCal Citygate Forward Gas Prices

The ICE SoCal Citygate forward price curve consists of the forward price curve for Henry Hub plus the SoCal Citygate basis. ICE produces a natural gas price curve for the SoCal Citygate destination five years into the future. Beyond 5 years, RPU has set CurveDeveloper to escalate the curve at 2% per year, which is in line with long term natural gas price forecasts from the California Energy Commission (CEC) and the Energy Information Administration (EIA). The SoCal CityGate ICE forward monthly price curve used to create all the forward price simulations considered in this IRP is shown in Figure 7.2.1. The front part of the curve in blue represents the actual ICE-published SoCal Citygate curve, and the balance of the curve in red represents the CurveDeveloper-generated extension (2% per year escalation). With the existing escalation factor, the SoCal Citygate natural gas price reaches $7.00/MMBtu by December 2033.

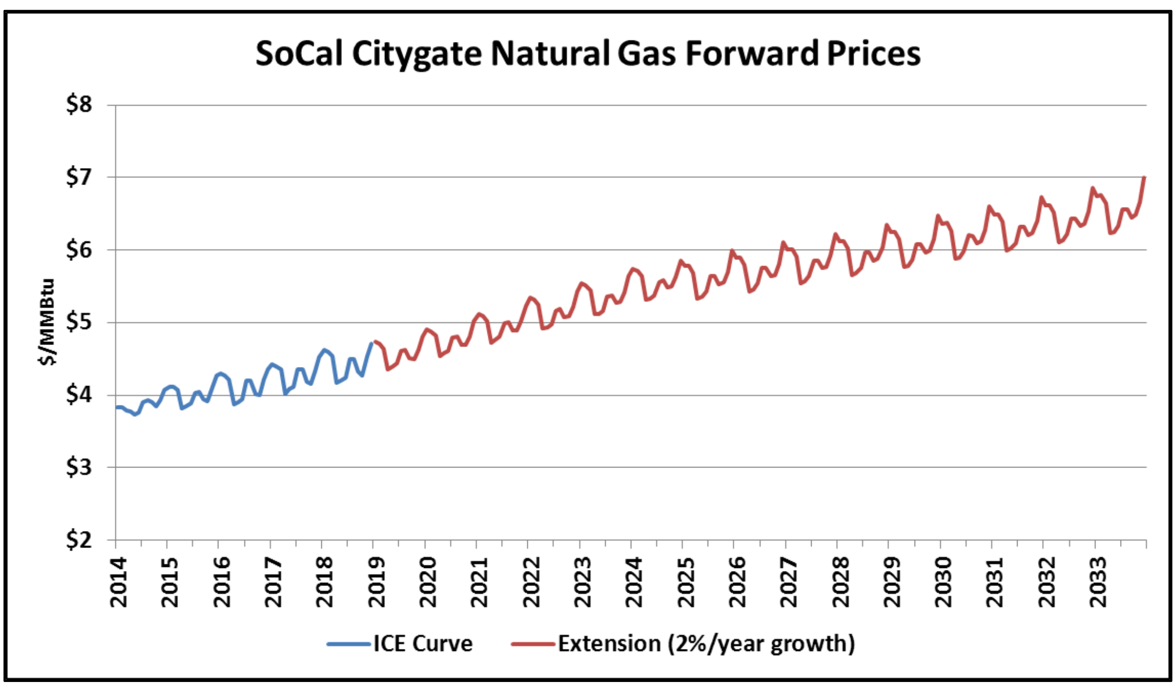


Figure 7.2.1. ICE natural gas forward prices for the SoCal Citygate Hub.

Under full simulation, the natural gas forward prices fluctuate based on the amount of volatility present in the (temporally referenced) forward curve input data. To illustrate, Figure 7.2.2 shows the standard deviation of the SoCal Citygate forward gas curve simulations, and Figure 7.2.3 shows the corresponding 90% confidence intervals around the mean (i.e., the 5th and 95th percentile levels). Note that in the confidence interval plots, the mean is derived from the input forward curve shown in Figure 7.2.1 above.

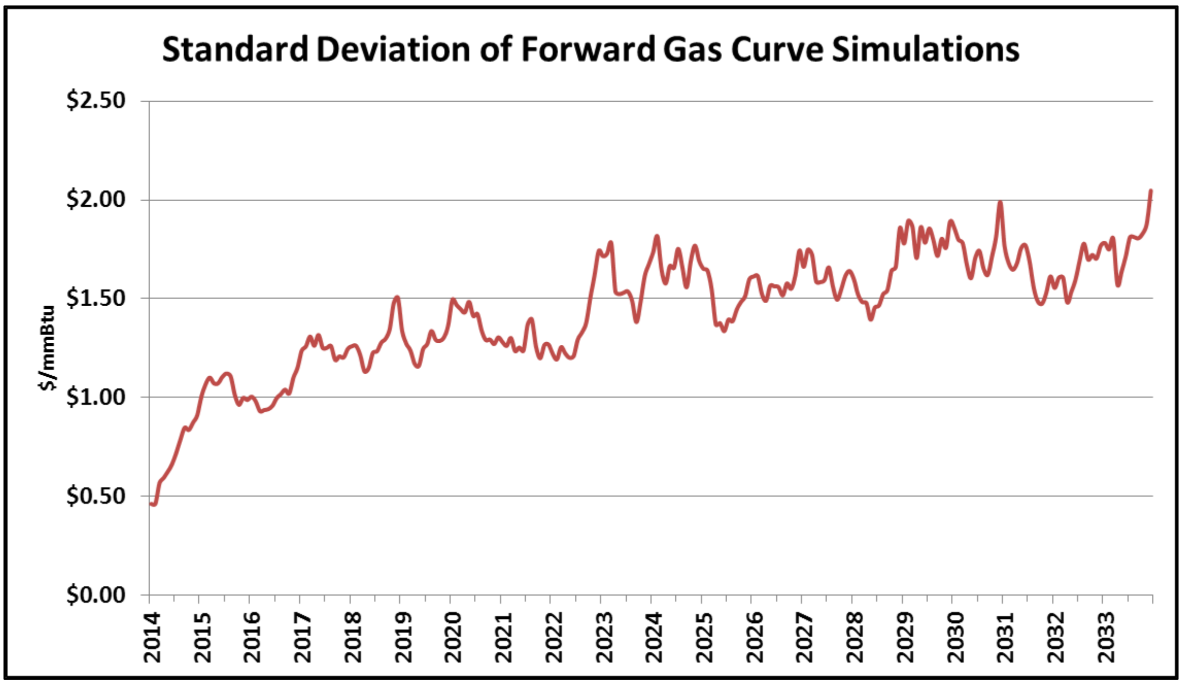


Figure 7.2.2. Standard deviation of SoCal Citygate forward curve simulations.

As shown in Figures 7.2.2. and 7.2.3, the gas price simulations exhibit a reasonable amount of volatility – standard deviations range from about $0.50 per mmBtu in January 2014 to about $2.00 per mmBtu in December 2033. The standard deviations are reflected in the forward gas curve confidence intervals, which show the ranges of simulated prices. As expected, the confidence intervals widen over time, reflecting increasing uncertainty, and the ranges of prices are consistent with current market expectations and historic perspectives of forward price uncertainty.

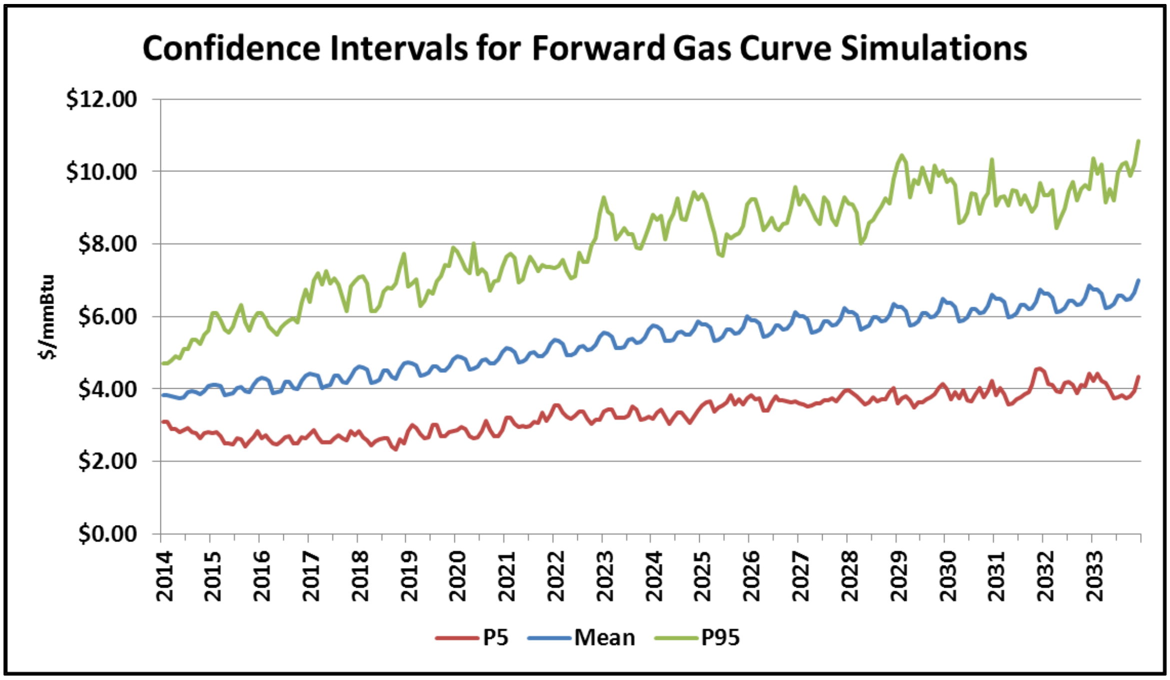


Figure 7.2.3. Confidence Intervals for simulated SoCal Citygate forward curve simulations.

7.2.1 Comparison of Natural Gas Price Forecasts

The CEC and EIA produce annual average forecasts of natural gas prices. The CEC and EIA natural gas forecasts are Reference Cases developed for the 2013 Integrated Energy Policy Report (IEPR) and 2013 Annual Energy Outlook (AEO), respectively. The CEC forecasts prices for the SoCal Gas Hub, while the EIA produces a forecast for Henry Hub. In order to produce a consistent comparison of these forecasted prices, ten cents was added to the EIA Henry Hub forecast to account for the SoCal Citygate basis. A comparison of these forecasts to the ICE forward curve is shown in Figure 7.2.4; note that all natural gas forecasts are shown in 2013 real dollars.

As shown in Figure 7.2.4, the ICE forward natural gas curve for the SoCal Citygate Hub is consistent with the CEC and EIA forecasts. The ICE curve falls in between the two forecasts and escalates at a comparable rate in the 2014 to 2033 time horizon – the ICE, EIA, and CEC projections have average annual growth rates (in real terms) of about 2.7%, 2.8%, and 2.1%, respectively. The majority of growth occurs in the near term until about 2018, which reflects the economy's recovery from the recent recession and an increase in demand for natural gas in the industrial and power sectors. Beyond 2018, natural gas prices continue to increase, though at a slower pace due to a sustained increase in production – the ICE, EIA, and CEC projections grow annually at about 2.4%, 2.3%, and 1.8%, respectively.

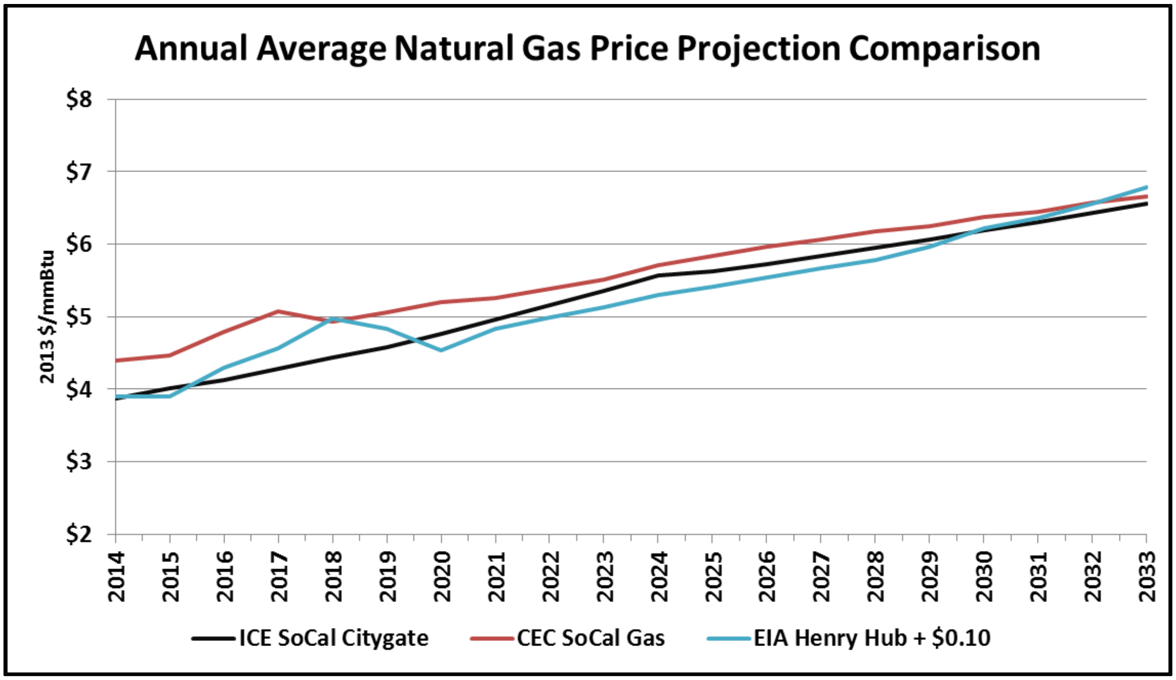


Figure 7.2.4. ICE, CEC, and EIA forward natural gas prices.

7.2.2 Shale Gas

U.S. natural gas prices have remained relatively low over the past several years and are projected to remain fairly low through the projection period. These lower prices are a result of prolific production of shale gas, which has greatly increased domestic natural gas supply, rejuvenated the natural gas industry, and moved the U.S. closer to energy independence.

Shale gas refers to a natural gas contained within shale rock formations. Because shale rock formations have low permeability, production of shale gas requires the use of special techniques to stimulate the flow of gas from the shale rock to the well. One such technique is hydraulic fracturing (commonly known as "fracking"), which involves pumping a fluid at high pressure into the shale rock formations to create small fractures so that gas trapped within the rock can escape into a well for collection. Depending on the well, different chemicals may be added to the fracking fluid to optimize the fracking process and ensure efficient production.

Despite the widespread economic benefits it brings, shale gas production is not free from controversy due to associated environmental and social impacts. Drilling and production activities for shale gas can be considerably more invasive, involving a larger geographical area, intensive well-drilling, depletion of freshwater resources, greenhouse gas emissions, and micro-earthquakes. Additionally, the use of chemicals in the hydraulic fracturing process has raised public concerns about the possible contamination of groundwater and the overall effects those chemicals have on public health. All of these concerns have placed substantial demands on federal, state, and local governments. For example, recent legislation has been passed in several U.S. states, including California, which require disclosure of chemicals and regulation of production methods. How well these new legislative and regulatory efforts address the environmental and social impacts will greatly influence the outlook for shale gas production and natural gas prices. Following the federal, state, and local regulatory developments surrounding shale gas production will likely serve as a good indicator of the future domestic and global outlook for natural gas as an energy source.

7.3 SP15 Forward Power Prices

ICE publishes Peak and Off-peak SP15 ICE electricity price curves seven years forward in time. Beyond the published term, CurveDeveloper has been set to escalate the curves at 2% per year. In addition, beyond one year the raw ICE curves provide quarterly average prices rather than monthly prices. To produce curves on a monthly-granularity, CurveDeveloper applies user-defined monthly shaping scalars to the raw ICE curves. The resulting on and off peak SP15 monthly forward curves are shown in Figure 7.3.1 below.

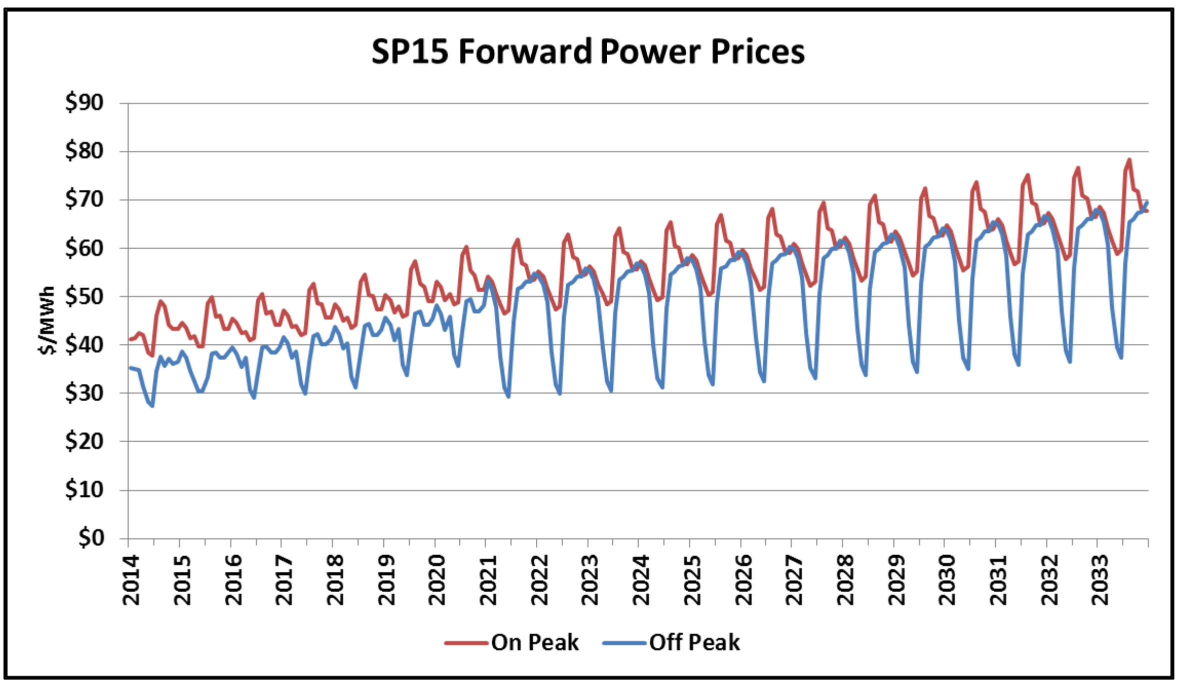


Figure 7.3.1. Shaped SP15 Peak and Off-peak ICE monthly forward curves.

As with the SoCal Citygate forward natural gas price curves, Portfolio Manager simulates forward power price curves and estimates the volatility present in the input power price data. Figure 7.3.2 shows the standard deviations associated with the SP15 forward price simulations.

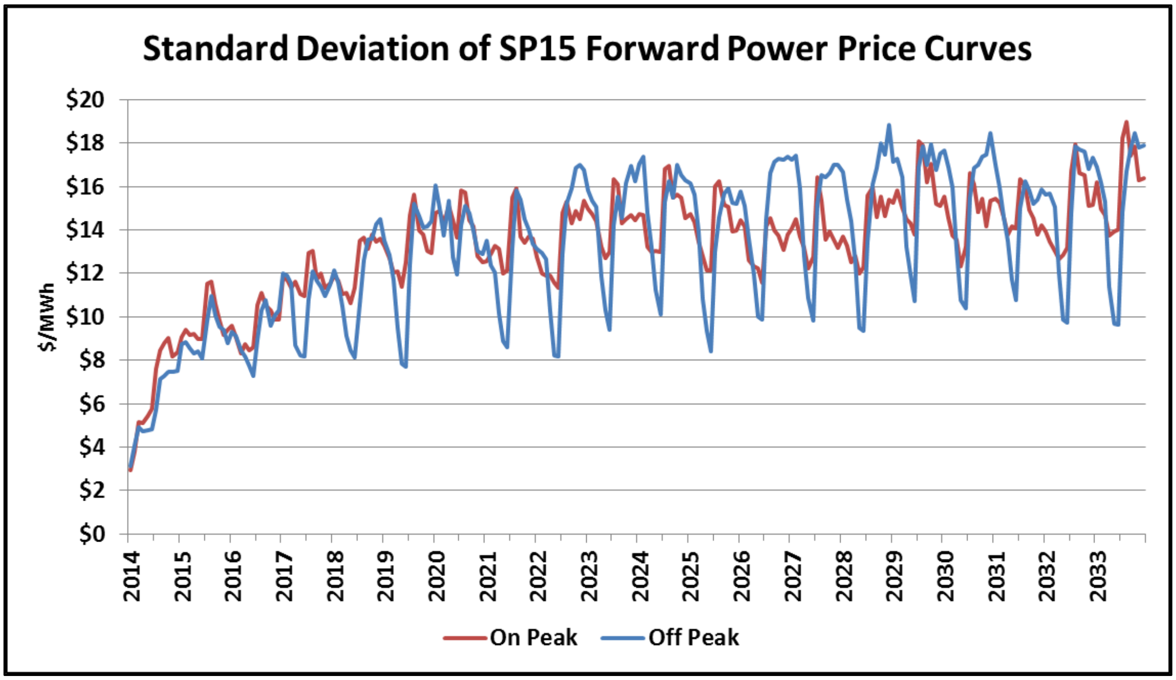


Figure 7.3.2. Standard deviation of SP15 Peak and Off-peak forward price simulations.

The standard deviations of the on and off peak forward power price simulations are reflected in the corresponding simulated confidence intervals. Figures 7.3.3 and 7.3.4 show the 90% confidence intervals for the Peak and Off-peak SP15 forward power price simulations (i.e., 5th and 95th percentile levels). As expected, the range in prices widens through time, reflecting increased uncertainty. However, the widening range in prices does not become unbounded, nor grow unreasonably over time.

It should be noted that the simulated SP15 forward prices are consistent with the simulated forward natural gas curves for SoCal Citygate, because the Ascend simulation engine has been calibrated to generate correlated price paths. This ensures that the Peak and Off-peak forward SP15 market heat rates, defined as the ratio of Peak and Off-peak SP15 power prices to the SoCal Citygate natural gas price, remain stable over time. In our IRP simulations, the SP15 Peak market heat rates fall between 9.3 and 12.5 MMBtu/MWh and the SP15 off peak market heat rates fall between 5.8 and 10.9 MMBtu/MWh, respectively.

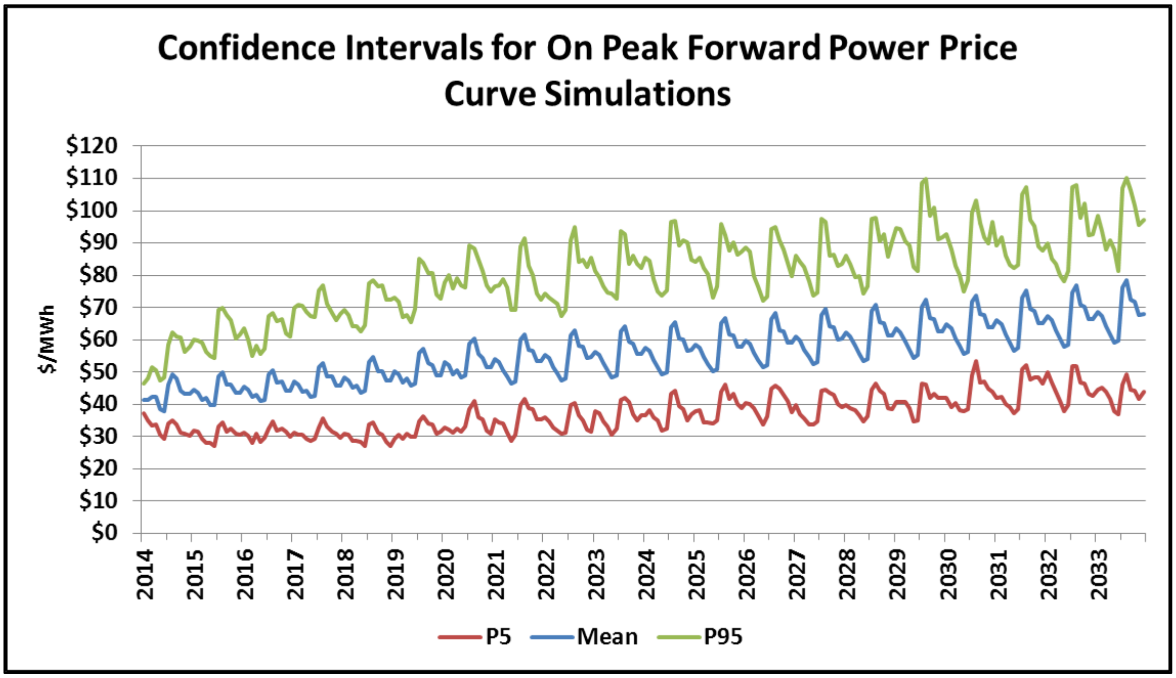


Figure 7.3.3. Confidence intervals for on peak forward price curve simulations.

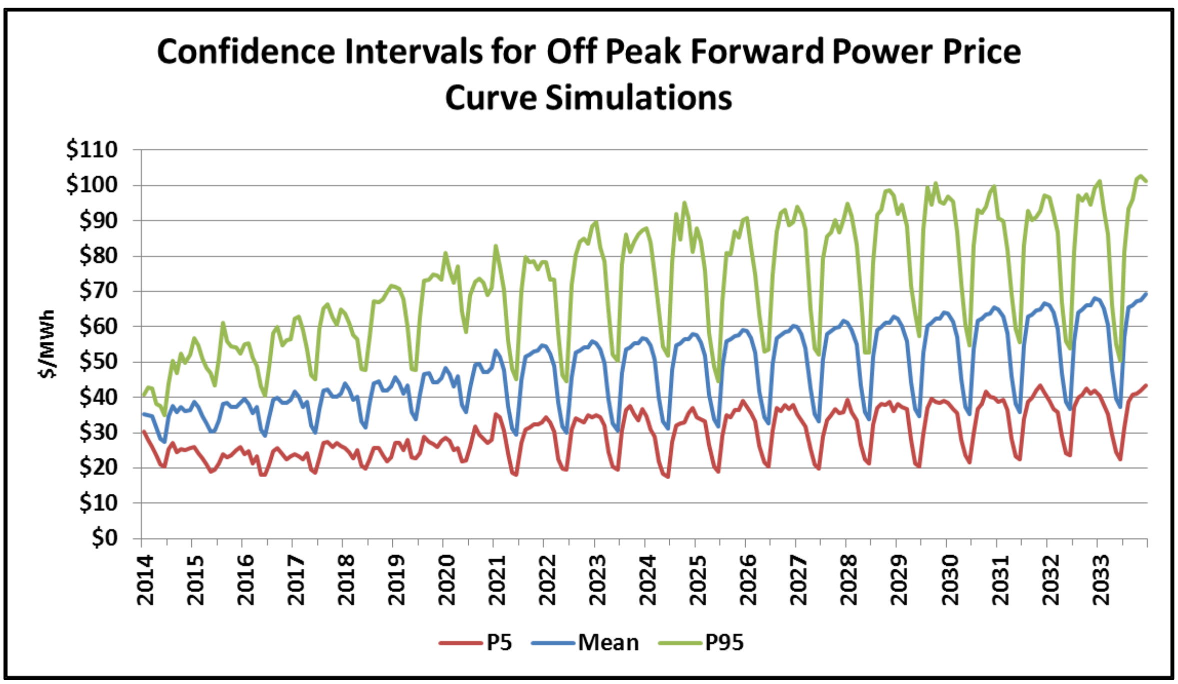


Figure 7.3.4. Confidence intervals for off peak forward price curve simulations.

8 Intermediate Term (Five-Year Forward) Power Resource Forecasts

This chapter presents a detailed overview of our most critical intermediate term power resource forecasts. These represent power supply forecasts and metrics that the Planning Unit routinely analyzes, monitors and manages in order to optimize Riverside's position in the CAISO market and minimize our associated load serving costs. The following metrics are discussed in detail in the indicated sections:

- Forecasted capacity, system peaks and Resource Adequacy needs (8.1)
- Renewable energy resources and projected RPS percentages (8.2)
- Primary Resource Portfolio metrics (8.3)
- Internal Generation forecasts (8.4)
- Forecasted Hedging percentages and Open Energy positions (8.5)
- Unhedged Energy costs and Cost-at-risk metrics (8.6)
- Forecasted GHG Emission profiles and net Carbon allocation positions (8.7)
- Five-year Forward Power Resource Budget forecasts (8.8)

With the exception of section 8.1, all of the analyses presented in this chapter were performed in the Ascend Portfolio Modeling software platform.

Note: In the initial version of this IRP, the original analyses discussed in this chapter pertained to the 2014-2018 time period, with reference to November 2013 CAISO market conditions. In practice, these forecasts are updated on a weekly basis, in order to reflect the latest CAISO market conditions and forward energy price curves. Therefore, as part of the fall 2014 IRP revision process, these analyses were updated to reflect more current market conditions. <u>Hence, the analyses presented in this chapter now pertain to the 2015-2019 time period, and reference December 2014 CAISO market conditions</u>.

8.1 Capacity, System Peaks and Resource Adequacy Needs

8.1.1. Current CAISO Paradigm

Figure 8.1.1 shows our expected monthly capacity amounts associated with our projected resource portfolio for the 2015-2019 timeframe. Note that our forecasted 1-in-2 system peaks and our 115% Resource Adequacy (RA) requirements are super-imposed over the capacity bar chart (blue and purple lines, respectively). Although we have enough generation capacity to meet our expected monthly system peaks in 2015, we cannot meet the 115% RA requirement during the Q3 summer months. Additionally, although we have contracted for new geothermal capacity in 2016 and 2019 and also extended our Hoover contract past 2017, it is currently unclear if we will be able to obtain RA credit for these resource additions and/or contract extensions. (This issue is discussed in greater detail in Chapter 9.) In the absence of such credit, we will not have enough capacity to fully meet our CAISO RA requirements during any Q3 summer months on/after 2016. Additional system or local RA will need to be forward purchased to satisfy this Resource Adequacy mandate.

Table 8.1.1 shows our expected cost forecasts to fill our short Q3 RA needs over the next five years, assuming that additional system RA purchases are executed by RPU to satisfy our CAISO RA requirements. We also assume that the recent 2014 Q3 system RA cost of $4.00/kW-month escalates at 3% annually. Under these assumptions, we anticipate spending 6.87 million dollars over the next five years to purchase additional system RA to meet our Q3 RA peaking needs.

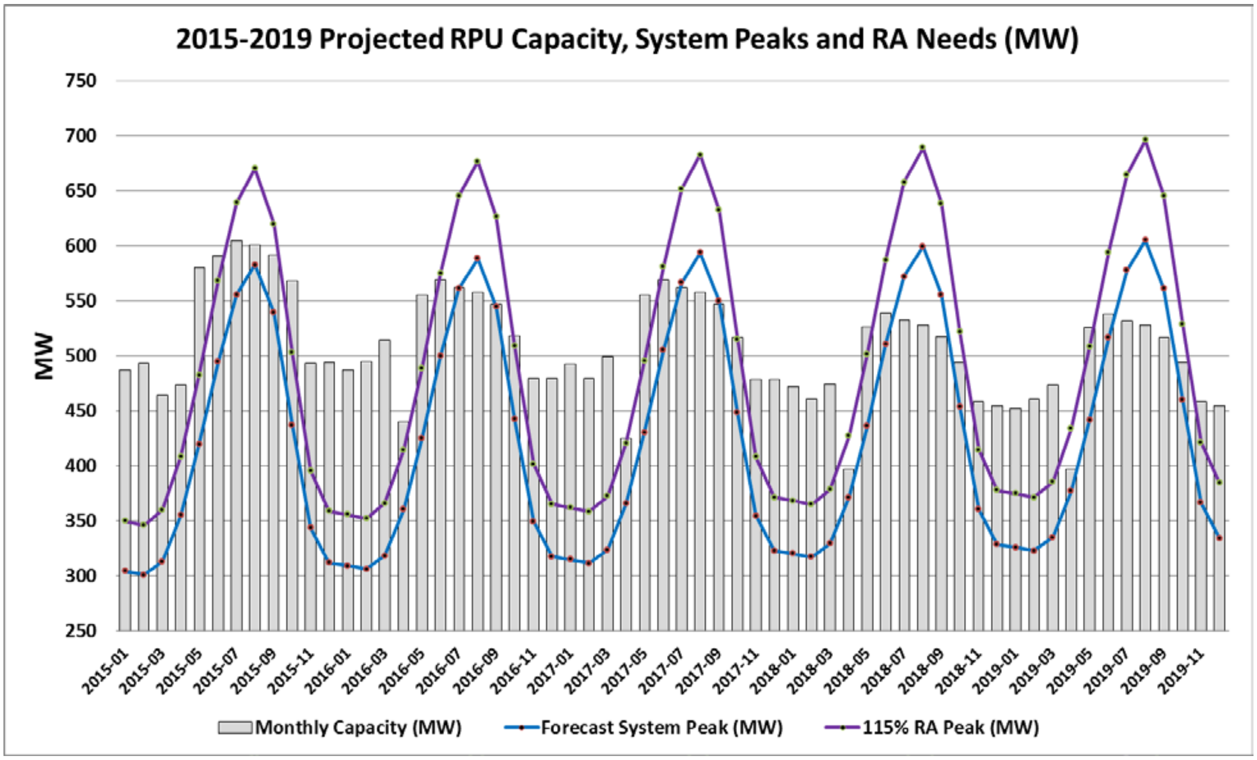


Figure 8.1.1. RPU 5-year forward capacity projections, system peaks and RA needs (2015-2019 timeframe).

Table 8.1.1. 2015-2019 short RA positions and expected RA cost forecasts.

Year	Q3 RA Needs (MW)	Q3 System RA Cost ($/kW-month)	Expected Cost (million $)
2015	132.3	$4.12	0.545 M
2016	280.4	$4.24	1.190 M
2017	299.4	$4.37	1.309 M
2018	408.6	$4.50	1.839 M
2019	429.0	$4.64	1.989 M
		Total 5-Year Cost Forecast ($):	6.872 M

The panel plot displayed in Figure 8.1.2 shows our normally available resources in our portfolio and our system load serving needs on typical winter (February) and summer (August) week days in 2016, by resource type. As shown in the summer panel plot, a significant amount of internal generation (or CAISO day-ahead market purchases) will be required to meet our typical summer daily system loads. It is worthwhile to note that most of our internal generation resources are use-limited and thus often preferentially dispatched to meet our summer peaking needs (whenever such dispatch is economically advantageous).

8.1.2 New FRAC/MOO Paradigm

It should be emphasized that the CAISO is currently conducting at least two major stakeholder processes that will reshape and redefine how RA capacity is determined and assigned to ISO participants. The most important stakeholder process is the Flexible Resource Adequacy and Enhanced Must Offer Obligation (FRAC/MOO process). The CAISO is pushing forward with this process due to the substantial penetration of intermittent resources in the coming years, since these intermittent resources have the potential to significantly affect CAISO system ramping requirements (i.e. to create the steep evening load ramping requirement shown previously in Figure 5.2.1). The FRAC/MOO paradigm is an attempt to resolve the anticipated operational needs, specifically the ramping needs in the CAISO footprint.

The FRAC requirement is defined on a monthly basis as:

<u>Monthly FRAC requirement = (a) monthly maximum three-hour net load continuous ramping + (b) maximum [MSC, 3.5% of monthly peak load] + (c) error term</u>

where

(a) represents the ramping requirement;

(b) represents the “reservation” of ancillary service capacity that CAISO fears would be lost to ramping needs if not reserved a priori; (MSC = Maximum Single Contingency); and

(c) represents a “fudge” factor that the CAISO can use to fine tune the requirement. It is expected that the error term will initially be set at zero.

Each FRAC component is allocated to the LSEs using different allocation methodologies as follows:

(a) the monthly maximum three-hour net load continuous ramping component will be allocated in four different ways: (1) contribution of LSE’s gross load ramping to the total ramping; (2) contribution of LSE’s intermittent wind resources ramping to the total ramping; (3) contribution of LSE’s intermittent solar PV resources ramping to the total ramping and (4) contribution of LSE’s intermittent solar thermal resources ramping to the total ramping;

(b) the “reservation” of ancillary service capacity component will be allocated based on monthly peak load ratio share of the LSEs; and

(c) the error term allocation appears undetermined at this time but likely to be based on peak load ratio share.

Once each LSE's FRAC requirement is determined, the LSE must provide suitable resources to meet the FRAC requirement as established by the CAISO. In the latest CAISO proposal, generation assets will be classified into generic "categories" of FRAC resources (i.e., Category 1, 2, and 3 resources). Category 1 thermal generation resources will be the most valuable and must have (a) 2 starts per day every day of the month and (b) minimum capable run time of 6 hours at the peak generating capacity every day. For Riverside, this will be highly problematic because of the limitations imposed by SCAQMD on our LM6000 RERC units.

Based on the latest CAISO stakeholder proposal, Riverside is only assured to have at most 100 MW of FRAC resources per month in our annual showing (50 MW from either RERC 1 or 2 and 50 MW from the aggregated RERC 3 and 4). When Riverside's monthly FRAC requirement is above 100 MW, Riverside will be exposed to additional flexible RA procurement costs (either bilaterally or through the CAISO backstop procurement mechanism). Staff has requested that the CAISO provide Riverside with estimates of Riverside's monthly FRAC requirements for CY 2015, in order to gauge the impact to Riverside at the start of the 2015 FRAC/MOO program. The current numbers provided by the CAISO show FRAC requirements in excess of 100 MW during the months of June (137 MW) , July (126 MW), and August (122 MW), respectively. Thus, RPU anticipates incurring approximately $300,000 to $500,000 in additional flexible procurement costs in 2015 alone.

It should also be noted that the CAISO has just initiated the Reliability Service market initiative. This second stakeholder initiative represents a continuation/broadening of FRAC/MOO effort in an attempt to "standardize" the CAISO RA capacity product. Key CAISO staff already indicated in the workshop forums and privately that the daily minimum run time of 6 hours will be revisited and could increase to as much as 17 hours per day. If this comes to fruition, the flexibility value of Riverside's RERC units will be further eroded and the cost of meeting CAISO operational RA requirements will continue to increase.

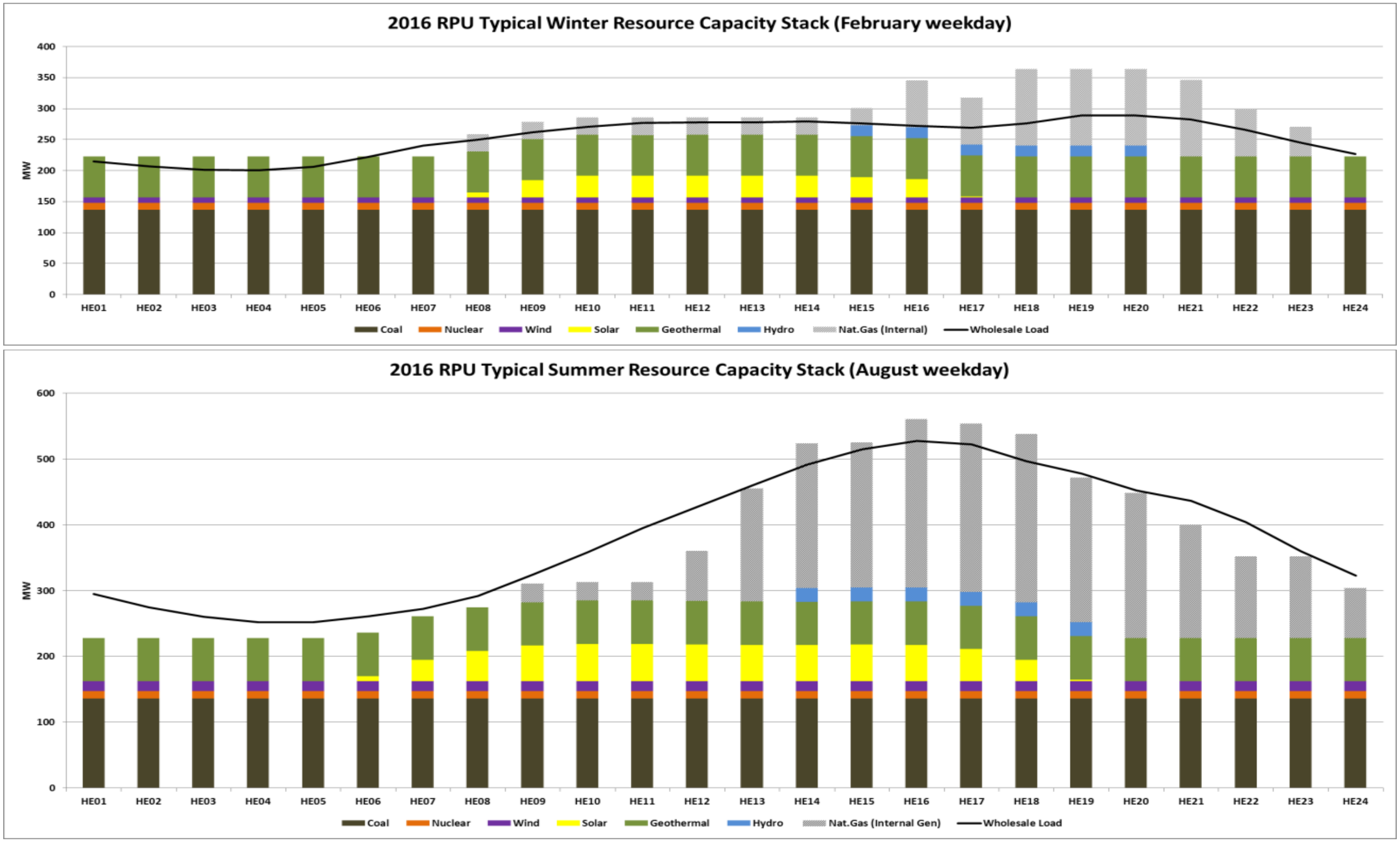


Figure 8.1.2. Typical winter and summer resource stacks and load serving needs: 2016 forecasts.

8.2 Renewable Energy Resources and RPS Mandate

As discussed in Chapter 3 (Section 3.3), a number of new renewable resources will begin delivering energy into the RPU portfolio within the next 24 months. Figure 8.2.1 shows our projected monthly RPS percentage levels for the 2015-2019 timeframe, after accounting for all of the aforementioned new renewable power purchase agreements (PPAs). Beginning in early 2016, RPU should exceed our minimum SB-2 25% RPS mandate by about 4%, reaching a 31% RPS in CY 2017 and then a 36% to 37% RPS in CY 2019. Additionally, it is worthwhile to note that all of these new renewable PPAs qualify as Portfolio Content Category 1 products under the SB-2 paradigm and the above mentioned RPS percentages do not include any Category 2 bundled renewable products or Category 3 tradable renewable energy credits (TRECs).

Table 8.2.1 quantifies some pertinent RPS statistics for the 2015-2019 time frame, including our expected versus mandated renewable percentages and associated energy costs (both total gross costs and net costs with respect to current CAISO market conditions). In 2015 we will need to purchase a limited about of Category 2 products or Category 3 TRECs to maintain a 20% RPS level. After this, we should rapidly become long in renewable energy credits (RECs). Riverside expects to carry-forward these RECs as eligible "excess procurement" credits that can be applied to meeting RPS mandates in future years. As shown in Table 8.2.1, we expect to pay an energy-weighted average of approximately $69/MWh to $76/MWh for all of our renewable resources over the next five years and expend an extra 1.1 to 3.6 million dollars per year to procure this excess renewable energy.

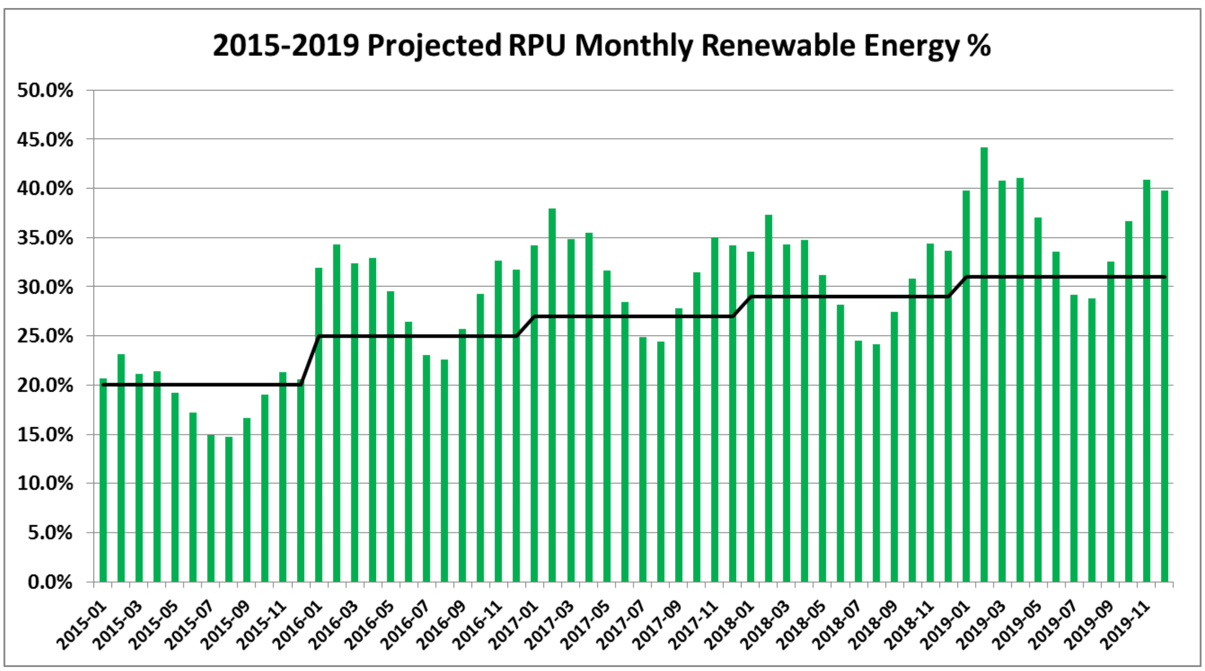


Figure 8.2.1. RPU five year forward renewable energy projections (2015-2019 timeframe).

Table 8.2.1. Pertinent RPU renewable energy statistics for the 2015-2019 timeframe.

Year	RPS Mandate (%)	Forecasted RPS (%)	Gross Price ($/MWh)	Net Price above CAISO Market ($/MWh)	Gross Costs above RPS Mandate (million $)	Net Costs above Market (million $)
2015	20%	18.8%	$68.76	$32.65	0 M	0 M
2016	25%	28.9%	$73.28	$32.36	6.390 M	2.821 M
2017	27%	31.1%	$73.98	$30.13	7.017 M	2.857 M
2018	29%	30.7%	$74.85	$28.78	2.890 M	1.111 M
2019	31%	36.4%	$75.88	$28.37	9.688 M	3.622 M
Total Incremental Costs (Gross and Net-to-CAISO Market, $):					25.985 M	10.411 M

8.3 Resource Portfolio: Primary Metrics

Figure 8.3.1 shows our projected monthly resource stacks in conjunction with our expected system loads for the 2015-2019 timeframe. Over the next five years, approximately 80% to 85% of our expected system energy needs will be served using fixed-price contracts within our resource portfolio (including optional IPP energy), while another 2%-3% will be served using our internal generation assets (primarily during summer). The remaining 12% to 18% of our energy needs will need to be acquired from the CAISO market, either via forward purchases or day-ahead market transactions. Note that after 2015, the majority of our open energy positions will occur during the months of March through September, with the greatest needs occurring in the March-April (IPP and Salton Sea outages) and July-September (summer peaking needs) periods.

In Figure 8.3.1, the “IPP-Decking” energy represents decremented IPP coal energy that is replaced with less expensive CAISO day-ahead market purchases. These market purchases quantify the amount of optional IPP energy that Riverside elects to not receive, under economic dispatch. It should be noted that in practice, our IPP resource can be “decked” in both the day-ahead and hour-ahead CAISO markets. However, the Ascend software platform only simulates day-ahead energy prices, so these simulated energy volumes just reflect day-ahead pricing conditions.

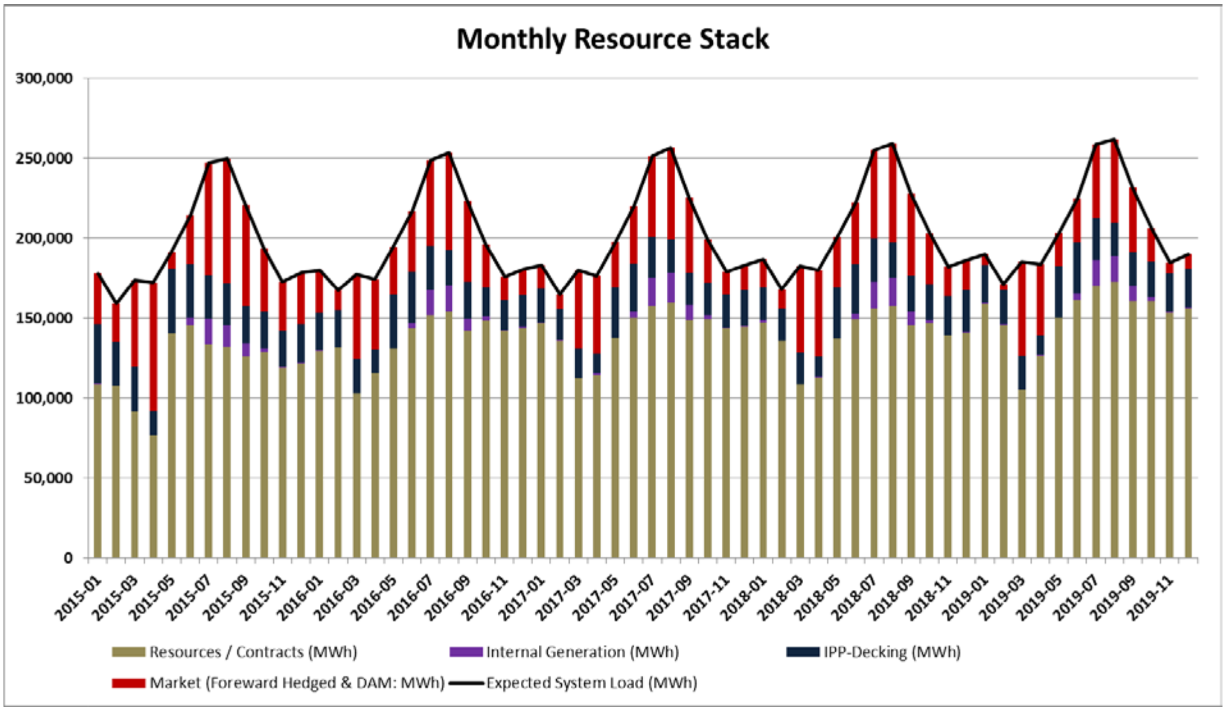


Figure 8.3.1. RPU five year forward resource stacks and system loads (2015-2019 timeframe).

Table 8.3.1 quantifies the forecasted annual energy volumes attributable to the resource categories shown in Figure 8.3.1, along with our expected system loads. The estimates for our internal generation, optional IPP-decking energy and net CAISO market purchases will vary with the prevalent CAISO market conditions; the values shown in Table 8.3.1 are referenced to December 2014 forward CAISO price forecasts. Note that the CAISO market purchases include both forward hedged energy contracts and net purchases in the day-ahead CAISO market. Additional details concerning our forecasted internal generation are also presented in the next section.

Table 8.3.1. 2015-2019 forecasted resource energy volumes and RPU system loads (GWh units).

Resource Stack	2015	2016	2017	2018	2019
Fixed resources/contracts	1,441.9	1,660.8	1,736.9	1,726.8	1883.3
Internal Generation	46.3	48.8	56.9	50.9	51.1
IPP-decking	328.6	277.6	262.6	280.2	281.1
Market DA & forward purchases	545.1	426.2	398.3	445.5	337.3
RPU System Load	2,361.9	2,413.4	2,454.7	2,503.4	2552.8

8.4 2015-2019 Internal Generation Forecasts

Figure 8.4.1 shows our forecasted monthly internal generation amounts for our RERC units, Springs units and our Clearwater co-generation unit for the 2015-2019 timeframe. Not surprisingly, about 75% of our annual internal generation is expected to come from our four RERC units, and all of our units primarily serve as summer (June-October) peaking resources. As discussed in Section 8.3, the Table 8.3.1 forecasted internal generation GWh volumes can change significantly in response to changing CAISO market conditions. (The standard deviation estimates associated with these annual generation forecasts increase from 24 to 49 GWh per year in the 2014-2018 timeframe.)

Table 8.4.1 summarizes the expected costs and revenue estimates associated with these internal generation forecasts under traditional economic dispatch assumptions (with a minimum $5/MWh profit margin). The total cost estimates include embedded Carbon emission costs, but exclude all debt related financing costs (i.e., bond debt associated with engineering, design and construction costs). The “net margin-to-market” column quantifies our expected internal generation profit margin (in $/MWh units), referenced to current market prices and subject to the above set of assumptions.

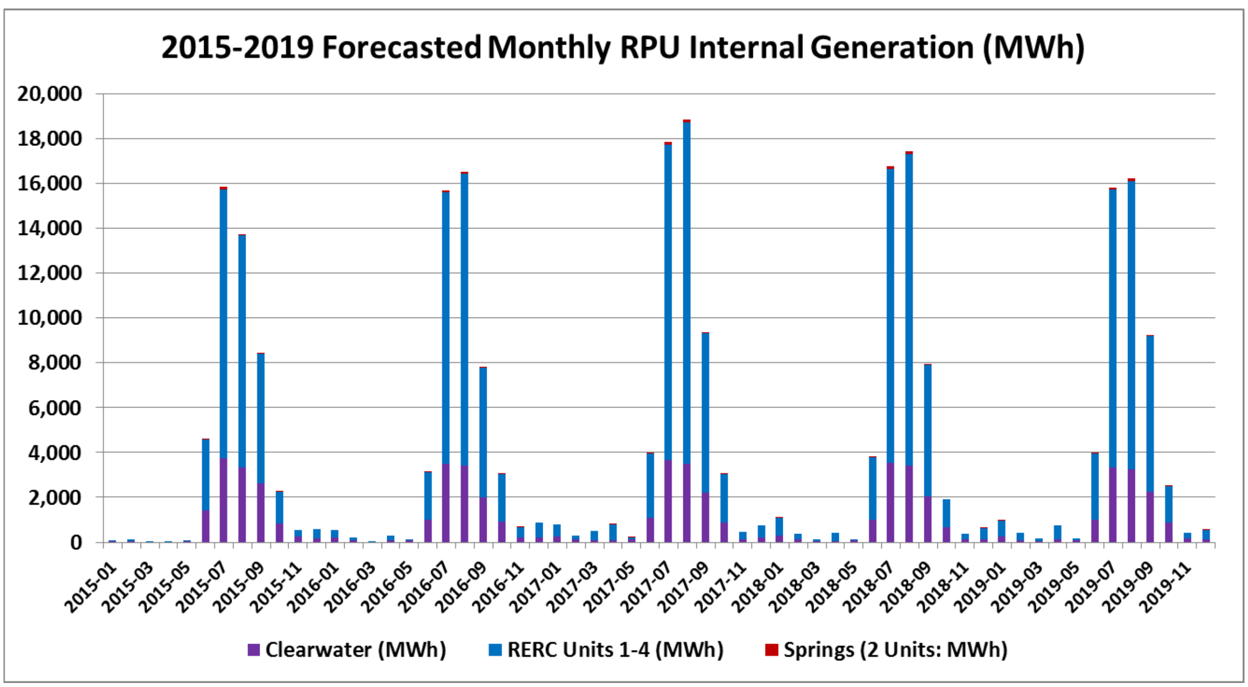


Figure 8.4.1. 2015-2019 forecasted monthly RPU internal generation amounts for RERC, Springs and Clearwater.

Table 8.4.1. 2015-2019 forecasted internal generation costs and revenues.

Internal Generation	2015	2016	2017	2018	2019
Total costs ($)	2.243 M	2.727 M	3.374 M	3.301 M	3.405 M
Total revenues ($)	2.971 M	3.567 M	4.411 M	4.259 M	4.362 M
Net revenue ($)	0.728 M	0.840 M	1.037 M	0.958 M	0.957 M
Net margin-to-market ($/MWh)	$15.73	$17.21	$18.23	$18.80	$18.73

8.5 Forecasted Hedging % and Open Energy Positions

RPU's current risk management strategy includes a conservative yet flexible hedging approach where fixed price natural gas and/or power purchases can be executed for delivery up to four years into the future. The primary goal of this hedging strategy is to preserve a reasonable degree of cash-flow (budget) certainty in the midst of potentially volatile forward natural gas and energy prices, by layering in fixed price purchases over time. RPU's Risk Management Committee (RMC) is responsible for establishing all acceptable energy and natural gas forward price limits and setting the annual and monthly hedging goals.

Currently, RPU quantifies its hedging needs using a volumetric measurement of the amount of fixed price energy in the portfolio, relative to its load serving needs. For any time period of interest (i.e., hour, day, month, etc.), we define the Net Energy Position (NEP) to be the difference between our expected system load and all of our hedged energy resources. Formally, the NEP is calculated as follows:

$$NEP = Sys.Load - Total.Gen - Hedged.Power - (Hedged.NGas - Burned.NGas)/10$$

In the above equation, all variables are expressed in either MWh or MMBtu units (for the appropriate time period) and defined as follows:

- Sys.Load = our wholesale system load
- Total.Gen = all fixed-price energy produced by any resource, including any internal generation and all available IPP energy
- Hedged.Power = the total delivery amount of all fixed-price forward purchases + the expected amounts of any call options (defined as the strike probability x the strike volume) – the total delivery amount of all fixed-price forward sales – the expected amounts of any put options (again defined as the strike probability x the strike volume)
- Hedged.NGas = the total delivery amount of all fixed-price forward gas purchases + the expected amounts of any gas call options (defined as the strike probability x the strike volume)
- Burned.NGas = the total volume of NGas consumed by all of our internal generation units

Note that the factor of 10 for the NGas component is used to convert MMBtu natural gas amounts into approximate MWh energy amounts, using an assumed heat rate of 10 MMBtu/MWh. This adjustment is included in the NEP calculation in order to account for (i.e., adjust out) any economically dispatched, "un-hedged" internal generation. Note also that the strike probabilities for all call and put options are determined under simulation. (For example, if an option is struck 15 times in 100 simulation runs then the strike probability would be calculated to be equal to 0.15. In turn, the expected energy delivery volume for this 10,000 MWh monthly call option would be 0.15 x 10,000 = 1,500 MWh, etc.)

In any given time period the NEP can be positive or negative. Positive values indicate short energy positions, while negative values indicate long energy positions. (Since RPU tends to be short resources to serve our expected system load, during most months the NEP will generally be positive). Finally, the effective hedging percentage (H%) is a direct function of the NEP. Formally, it is calculated as

$$H\% = 100 \times [\,Sys.Load - NEP\,] \,/\, Sys.Load$$

where the Sys.Load and NEP variables are defined as above. In any time interval when the NEP = 0, RPU is effectively 100% hedged for that time interval.

Figure 8.5.1 shows RPU's forecasted monthly hedging percentages for the 2015-2019 timeframe. Our risk management guidelines currently require that within 30 days of each month, our H% for that month in question must be within 85% to 115%; the Planning Unit coordinates with Market Operations to ensure that each prompt month satisfies this constraint. In December 2014, the RMC set the minimum annual H% targets shown in Table 8.5.1 for the 2015-2018 timeframe; RPU's current annual H% values are also shown in this table. Some additional 2015-2017 hedging activities need to be performed to bring these years up to their minimum H% targets.

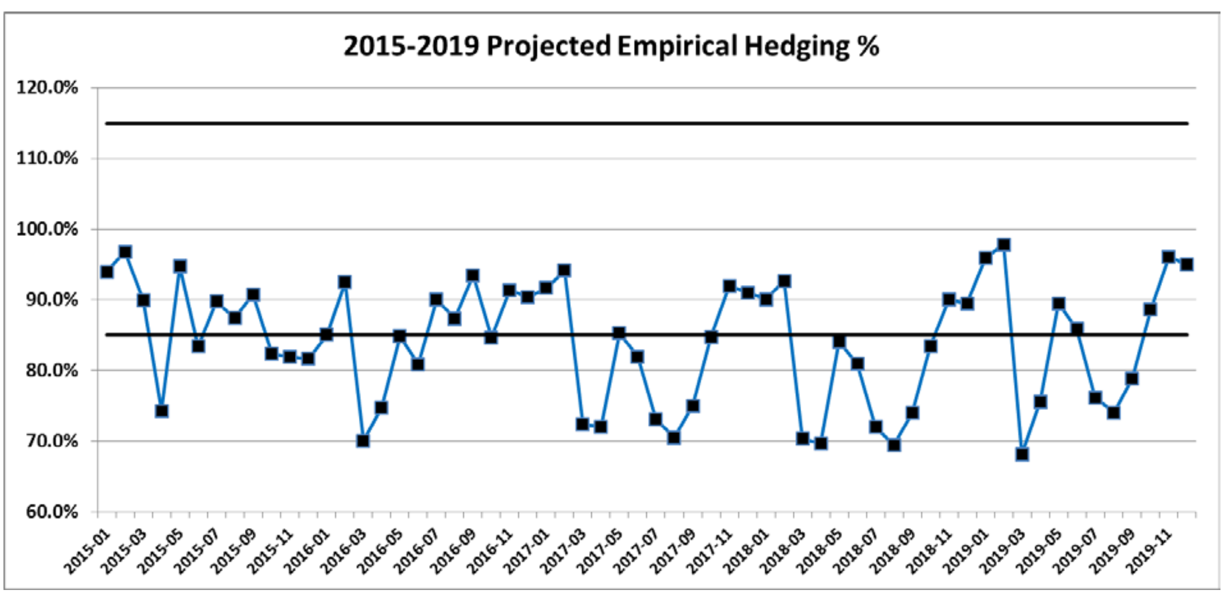


Figure 8.5.1. Forecasted monthly RPU hedging percentages for the 2015-2019 timeframe.

Table 8.5.1. RMC target versus current actual annual hedging percentages (H%); 2015-2019 timeframe.

Hedging Metric	2015	2016	2017	2018	2019
RMC Target Annual H%	95%	90%	85%	80%	n/a
Current NEP (GWh)	298.1	341.2	453.4	494.8	386.7
Current Annual H%	87.3%	85.7%	81.2%	79.8%	84.5%

RPU has traditionally layered in natural gas hedges over a three year forward window, while implementing its power hedges over a one-to-two year forward window. Part of this strategy has been driven by attractive Q3 market heat rates, along with the increased flexibility that natural gas hedges offer (e.g., the ability to trade out the gas for power under changing market heat rate conditions). RPU's current set of forward hedges reflect this general strategy, although our current hedges extend over a shorter timeframe. In 2014, RPU forward hedged 401,325 MWh of fixed price HL and LL SP15 energy products and 1,077,500 MMBtu of natural gas. A similar hedging strategy is currently being employed for 2015.

The NEP metric can be conveniently used to quantify open short or long energy positions on either a MWh or MW/h basis. Figure 8.5.2 shows our forecasted monthly open energy positions on a MWh/month basis. Likewise, Figure 8.5.3 shows our corresponding monthly MW/h short (or if negative, long) LL and HL energy positions. In principal, if RPU were to buy (or sell) LL and HL energy products that exactly match these open energy positions, we would achieve a 100% hedging percentage for each month of the year. Hence, these open positions effectively define our "unhedged" load serving needs for the 2015-2019 timeframe.

As shown in Figures 8.5.2 and 8.5.3, there are still some significant open energy positions in 2015 and 2016, particularly those associated with March-April IPP and Salton Sea outage events and Q3 summer months. The Q3 HL open positions increase significantly in 2017; this is a direct result of the expiration of our BPA-II energy exchange contract (i.e., the loss of our summer Bonneville peaking energy). Additionally, the magnitudes of these open positions grow more pronounced in 2018, before reducing somewhat in 2019 (when additional geothermal energy comes online). Table 8.5.2 summarizes our annual open LL and HL energy positions on both a GWh and MW/h basis for the next five years; note that the GWh values shown in Table 8.5.2 partition out the NEP GWh (shown in Table 8.5.1) across LL and HL hours, respectively.

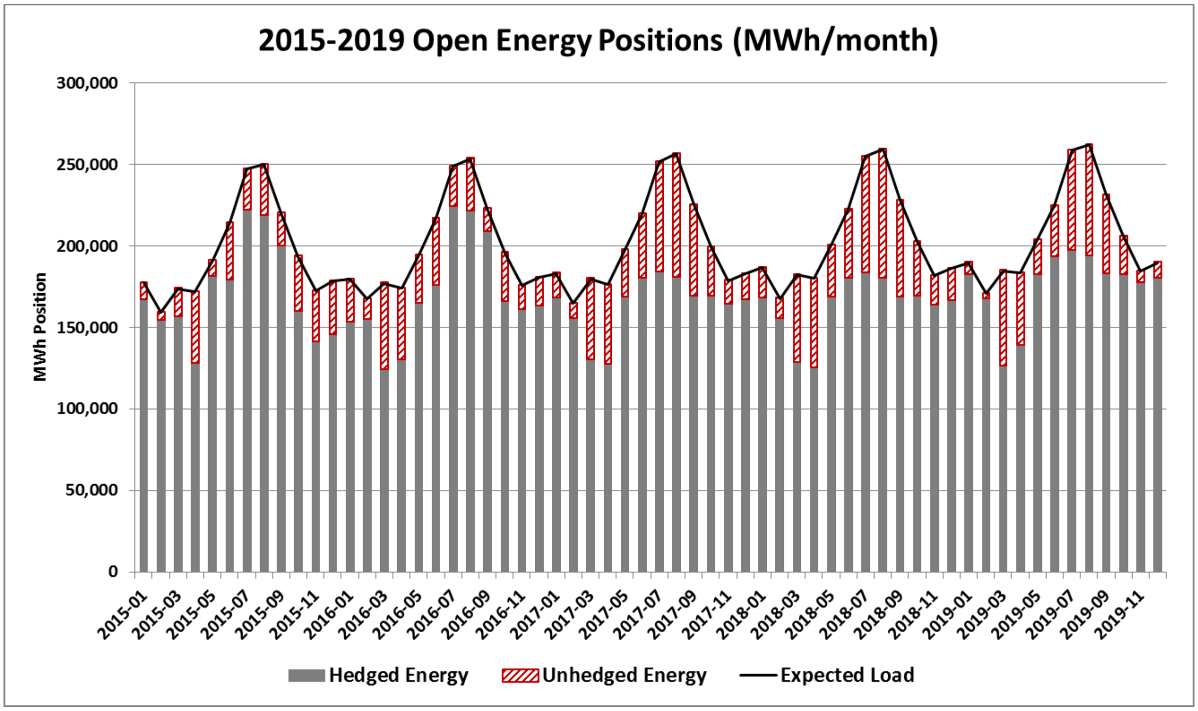


Figure 8.5.2. 2015-2019 NEP forecasted monthly open energy positions (MWh/month).

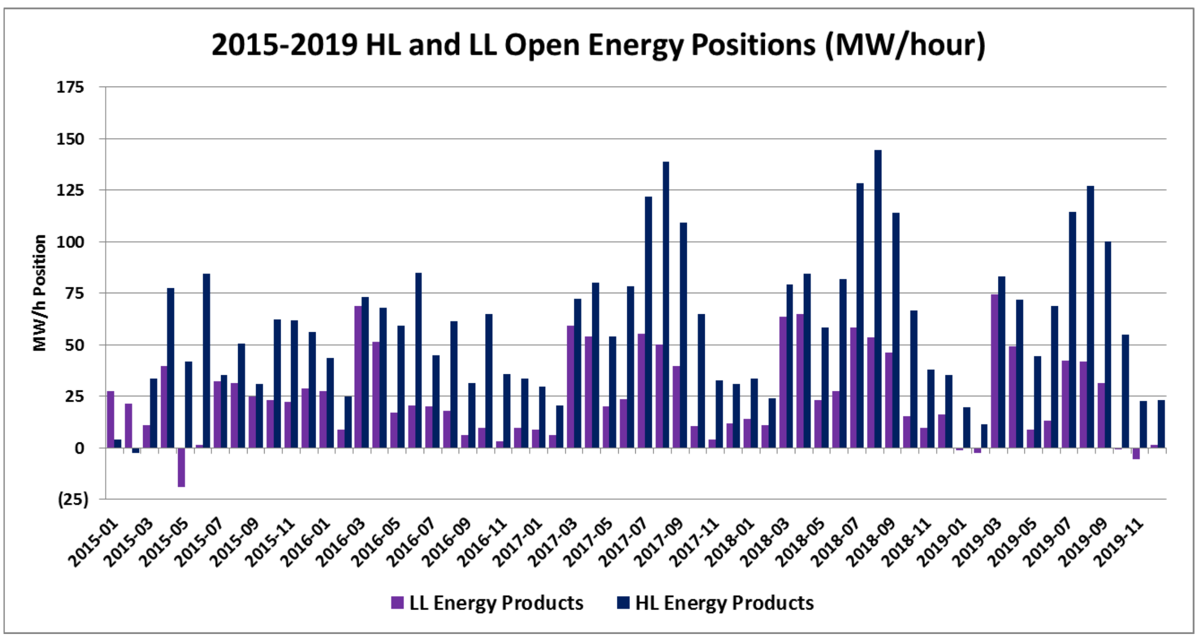


Figure 8.5.3. 2015-2019 NEP forecasted monthly open HL and LL energy positions (MW/hour).

Table 8.5.2. Open (unhedged) RPU annual LL and HL energy positions; 2015-2019 timeframe.

Energy Metric	2015	2016	2017	2018	2019
LL (GWh)	77.1	82.6	110.3	129.9	81.0
HL (GWh)	221.0	258.6	343.0	364.9	305.7
LL (MW/h)	20	22	29	34	21
HL (MW/h)	45	52	70	73	62

8.6 Unhedged Energy Costs and Cost-at-Risk Metrics

For any given hour of a particular day, a forecast of our hourly unhedged energy cost (HUEC) can be expressed as

$$HUEC\ (\$/h) = NEP\ (MWh/h) \times E_{PRICE}\ (\$/MWh)$$

where the HUEC is found by multiplying the NEP by a suitable forecast of that hour's energy price. These hourly values can then be summed over any time interval of interest to produce a cumulative unhedged energy cost or revenue (UEC) estimate for eliminating ("closing") a short or long energy position. For example, the Ascend software produces daily updated forecasts of our future expected HL and LL UECs for each month of the year. The Ascend software can also calculate the corresponding standard deviations associated with these forecasted estimates; these standard deviations are in turn used to calculate unhedged energy "cost-at-risk" (CAR) metrics. Under the assumption that the simulated UEC forecast follows a Lognormal distribution, a reasonable CAR metric can be defined as *CAR = 1.90 x Std(UEC)*, where *Std(UEC)* represents the calculated standard deviation of the cumulative unhedged energy cost. (Justification for the 1.90 factor is given in Appendix C.)

Figure 8.6.1 shows our forecasted monthly UECs for our unhedged HL energy, LL energy, and natural gas positions in the 2015-2019 timeframe. These cost estimates have been computed by rolling up the future HL and LL NEPs and then multiplying these positions by their corresponding monthly forward energy prices. Note that we also assume that approximately 50% of the open Q3 HL positions will be hedged using natural gas, and that the corresponding necessary gas volumes can be estimated using a conversion factor of 10 MMBtu/MWh. Similarly, Figure 8.6.2 summarizes these monthly forecasts into annual cost estimates. For example, as of December 2014 (when these revised estimates were produced), the expected cost to completely hedge all of RPU's open 2015 LL energy positions was 2.486 million dollars. Likewise, the expected cost to hedge RPU's open HL energy positions in 2015 was 8.864 million dollars.

As discussed above, a CAR metric can be computed for each UEC estimate. Figure 8.6.3 shows the associated CAR metrics for the monthly LL and (HL + natural gas) estimates shown in Figure 8.6.1. Not surprisingly, RPU's cost-at-risk indices grow over time. It is typical for CAR metrics to increase in magnitude over extended time horizons, if the open energy positions also increase in magnitude over time.

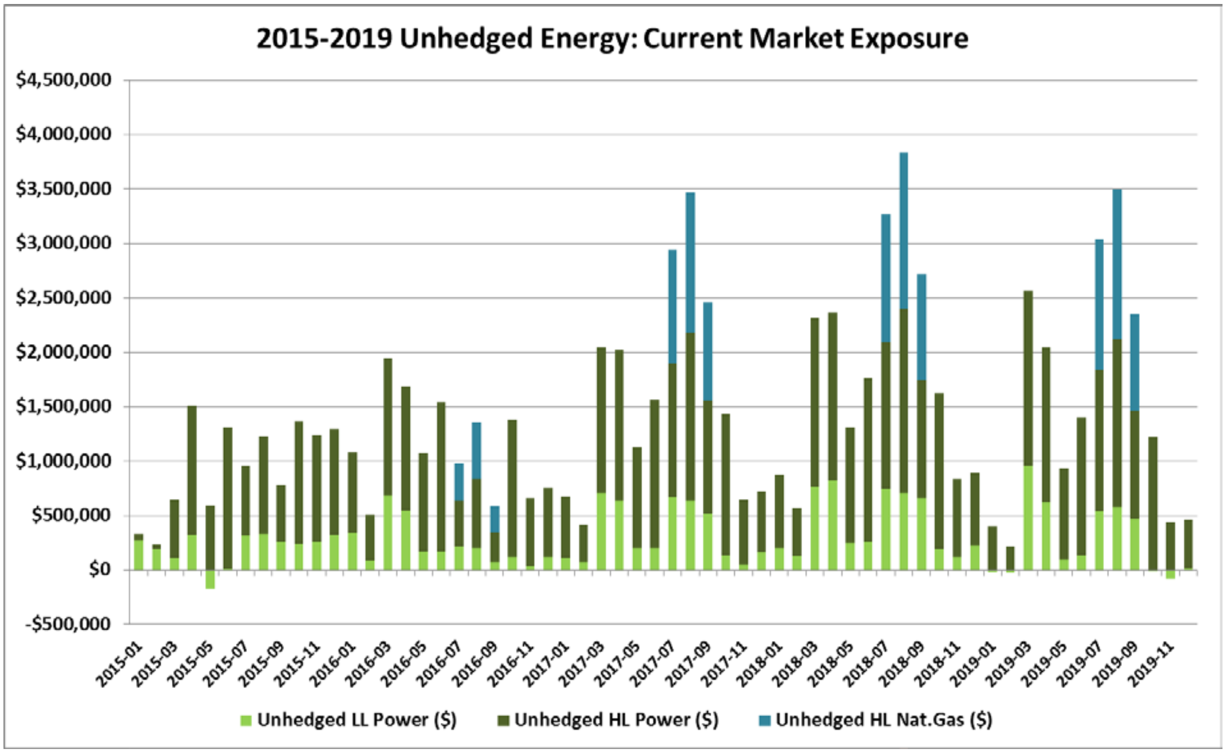


Figure 8.6.1. Forecasted monthly HL, LL, and natural gas unhedged energy costs: 2015-2019 timeframe.

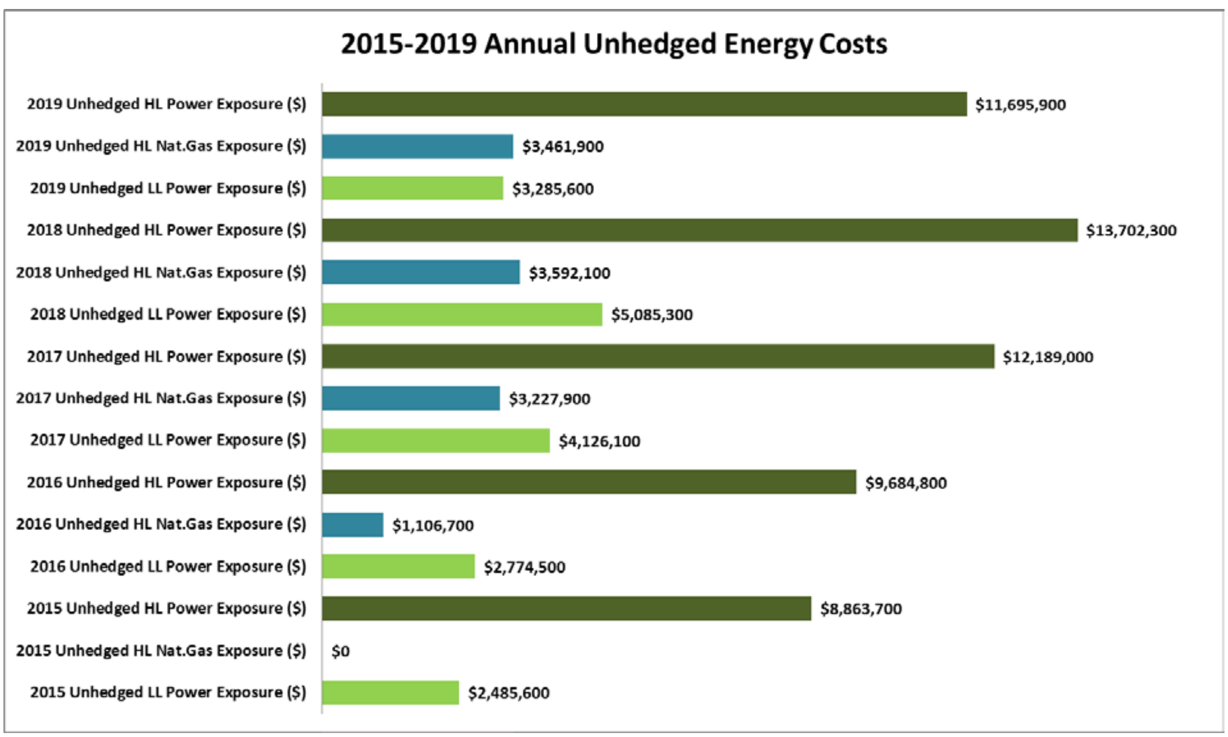


Figure 8.6.2. Forecasted annual HL, LL, and natural gas unhedged energy costs: 2015-2019 timeframe.

It is important to realize that while the CAR metrics shown in Figures 8.6.3 summarize the rolled-up cost uncertainty for specific time intervals, they do so at the hourly granularity level. Therefore, these metrics quantify both the cost uncertainty associated with the average open energy position for the respective time interval, and also the hour-to-hour uncertainty resulting from stochastic deviations in the expected weather, load and generation patterns. More formally, the variance of the UEC estimate can be partitioned into two distinct components, i.e.,

Var(UEC) = Var(UEE) + Var(Net-0)

where *Var(UEE)* represents the "unhedged energy exposure" variance associated with the average open energy position for the time period of interest, and *Var(Net-0)* represents the residual hour-to-hour variance caused by random deviations in the expected weather, load and generation patterns, assuming that the average open energy position is 0 (i.e., under a "Net-0" position assumption). Traditional forward hedging purchases or sales can only reduce the *Var(UEE)* component; the *Var(Net-0)* component will still exist even if the portfolio is perfectly hedged on average. Note that the black line in Figure 8.6.3 partitions the monthly CAR metrics into these two components, respectively.

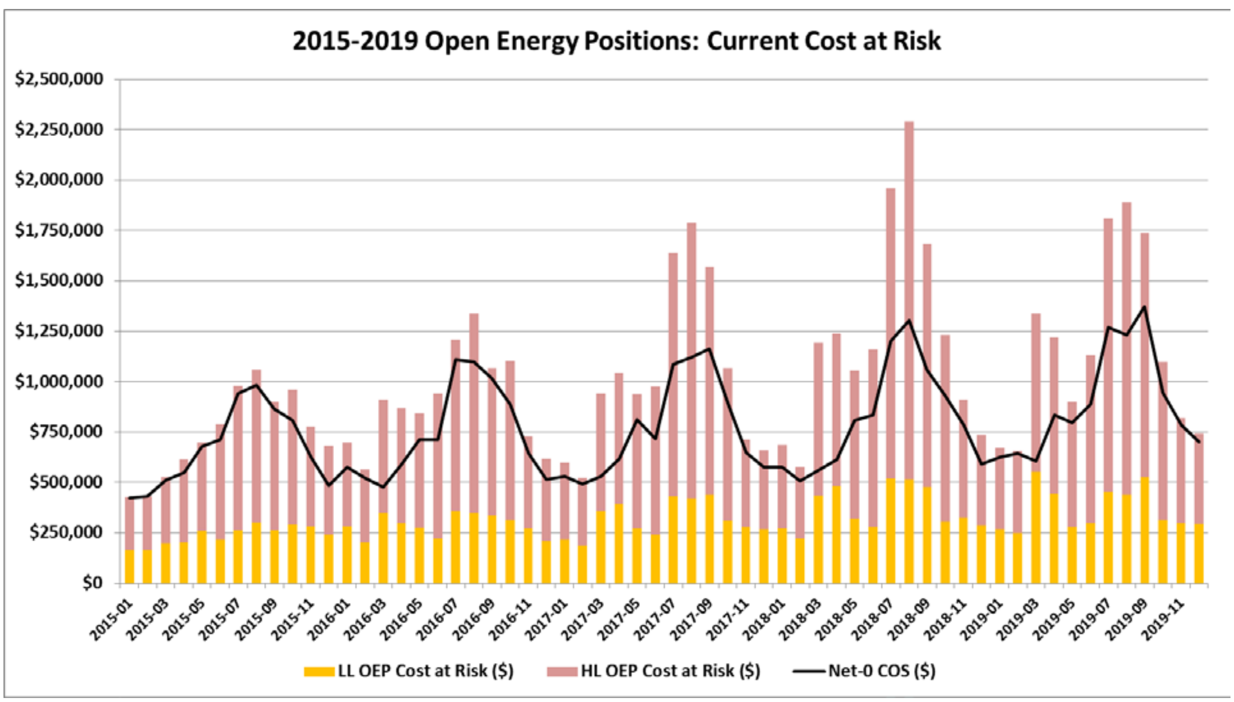


Figure 8.6.3. Forecasted cost-at-risk (CAR) metrics for the monthly UEC estimates shown in Figure 8.6.1.

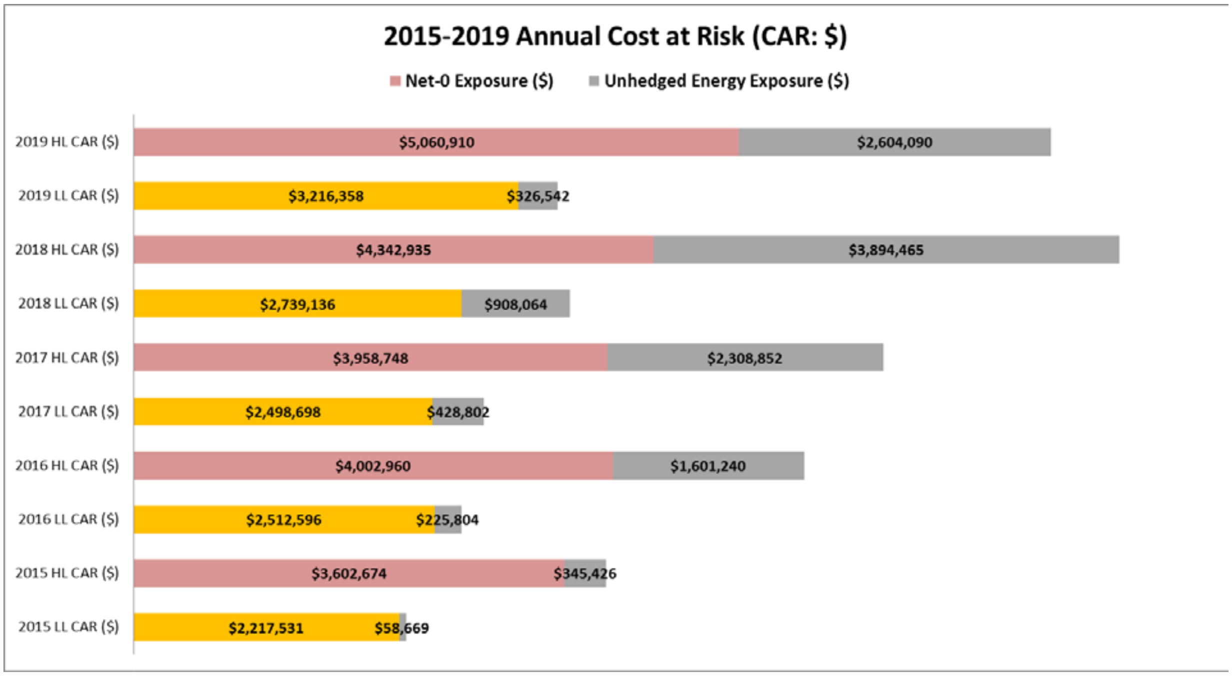


Figure 8.6.4. Forecasted annual UEE and Net-0 cost-at-risk (CAR) metrics for the annual UEC estimates shown in Figure 8.6.2.

Figure 8.6.4 shows how much the CAR metrics can be reduced, assuming that the forward portfolio was perfectly hedged (i.e., all the average open monthly energy positions were closed, etc.). Given RPU's current degree of hourly load and generation uncertainty, we should still expect about 2.22 and 3.60 million dollars to be at risk in 2015 during LL and HL time periods, even under an ideal, 100% hedged scenario. Our Net-0 CAR metrics increase over time, in direct proportion to our increasing uncertainty about future market prices. In contrast, our UEE CAR metrics reach their peak in 2018, which represents the year in the 2015-2019 timeframe with the largest amount of open energy positions (see Table 8.5.2). Note that the Net-0 CAR figures represent our baseline, minimal cost-at-risk conditions for our current resource portfolio, under a 100% fixed-price hedging strategy that avoids the use of any additional market options or derivatives.

In summary, although RPU needs to perform additional forward hedging activities in calendar year 2015, a significant majority of the remaining unhedged energy cost-at-risk is associated with stochastic hour-to-hour load and generation deviations that will not be further mitigated using fixed price monthly purchases or sales. However, longer term forward hedging strategies can be effectively used to reduce our UEE CAR metrics in 2016 and beyond, particularly during the HL time periods. Given our current resource portfolio, the majority of these hedging activities should be focused towards closing our open June through October summer energy positions and compensating for our March – April outage events, at least for the next five years.

8.7 GHG Emissions, Allocations and Positions

The California Air Resources Board (CARB) is the lead regulatory agency implementing the AB 32 directives to reduce GHG emissions. CARB finalized its implementation regulations in early 2012, including the allocation of GHG allowances to all eligible California LSEs for calendar years 2013 through 2020. Table 8.7.1 shows RPU's annual allowance amounts for the 2015-2019 timeframe, along with our annual forecasted 1st deliverer emission levels for this same period. Likewise, Figure 8.7.1 shows our forecasted 1st deliverer carbon emission levels by resource, at a monthly granularity level. As can be seen in this figure, the bulk of RPU's emissions are associated with our IPP coal contract. In general, RPU's annual emission levels are nearly proportional to the volume of energy deliveries received from this resource.

Table 8.7.1. RPU's annual carbon allocations and GHG emission profiles (million metric tons): 2015-2019 timeframe.

	2015	2016	2017	2018	2019
CARB Allocations (MMT)	1.043	1.066	1.068	1.083	1.076
RPU Emissions (MMT)	0.742	0.786	0.801	0.779	0.776

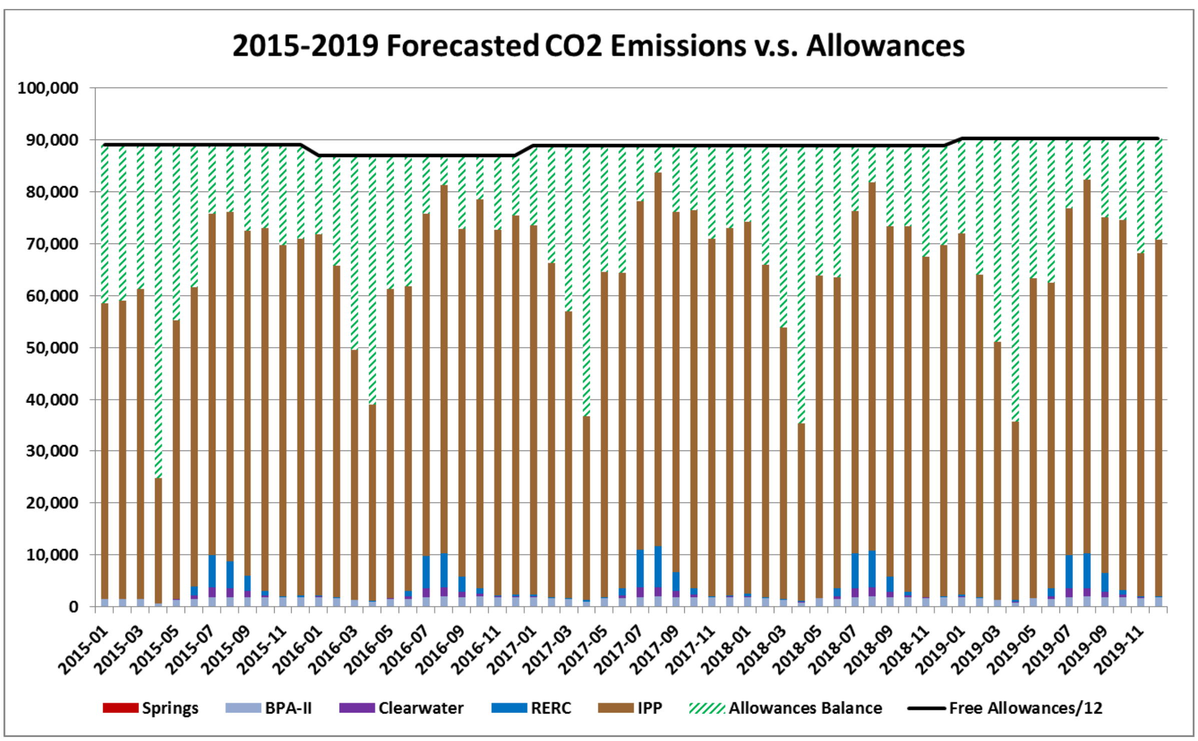


Figure 8.7.1. Forecasted monthly RPU carbon emission levels, by resource: 2015-2019 timeframe.

Table 8.7.2 quantifies RPU's expected annual surplus carbon allowance positions for the same 2015-2019 time period, before accounting for any embedded carbon costs in RPU's net CAISO market purchases. These surplus allowances are expected to be monetized through the quarterly CARB Carbon auction process; Table 8.7.2 shows the corresponding expected cash flow streams under two auction price scenarios. The first scenario represents the forecasted allowance floor price (imposed by CARB), while the second scenario represents our current carbon price curve assumptions as of December 2014. Assuming that the second scenario represents a reasonable auction ceiling price for the next five years, RPU can expect to receive 19.72 to 23.26 million dollars in revenues from the sale of excess allowances. Currently, it is anticipated that this revenue stream will be used to help offset costs associated with other legislatively imposed carbon reduction programs; such as the RPS program (e.g., to help offset RPU's incremental gross RPS costs shown in Table 8.2.1).

Table 8.7.2. Expected annual surplus carbon allowance positions and associated revenue streams: 2015-2019 timeframe.

Year	Net Allowance Surplus (MMT)	Auction Floor Price ($/ton)	Revenue Stream (M $)	Projected CO2 Price ($/ton)	Revenue Stream (M $)
2015	0.301	$12.03	3.623	$14.00	4.217
2016	0.280	$12.76	3.580	$15.00	4.208
2017	0.267	$13.52	3.611	$16.00	4.273
2018	0.304	$14.33	4.356	$17.00	5.167
2019	0.300	$15.18	4.550	$18.00	5.395
Total	1.452		19.720		23.260

RPU has been actively trying to incrementally reduce its GHG emissions since the enactment of AB 32. Figure 8.7.2 shows RPU's 1st deliverer and total emission profiles from 2006 through 2019 (i.e., 2006-2013 actuals, 2014 estimated, and 2015-2019 forecasts). The downward trends apparent in both profiles are a direct result of the following forward planning activities: (a) the termination of our Deseret coal contract in late 2009, (b) the decision to increase in our Salton Sea V renewable contract capacity from 20 MW to 46 MW in June 2009, (c) the decision in 2012 to begin economically dispatching our incremental IPP energy subject to its embedded carbon costs, and (d) RPU's commitment to procure significant amounts of new renewable resources to meet our anticipated future load growth and replace our lost SONGS energy.

Note that the total emission profile shown in Figure 8.7.2 is defined to be equal to our 1st deliverer levels plus the estimated amount of carbon emissions contained in our net CAISO market purchases. RPU is not required to report these latter emissions to CARB; the generation entities that produce these emissions must report them instead. Notwithstanding this issue, the total emission profile presents a more accurate picture of our actual carbon footprint with respect to our total load serving needs. Following this logic, Figure 8.7.3 shows our "load normalized" carbon footprint, on a metric ton per MWh basis. This metric is defined to be equal to our total emission profile divided by our total system load serving needs, respectively, and can be used to track and forecast our "carbon output" per unit of "system energy input". This represents another complimentary way to show Riverside's "load normalized" carbon emission profile, and clearly demonstrates that RPU is committed to systematically reducing its overall carbon footprint.

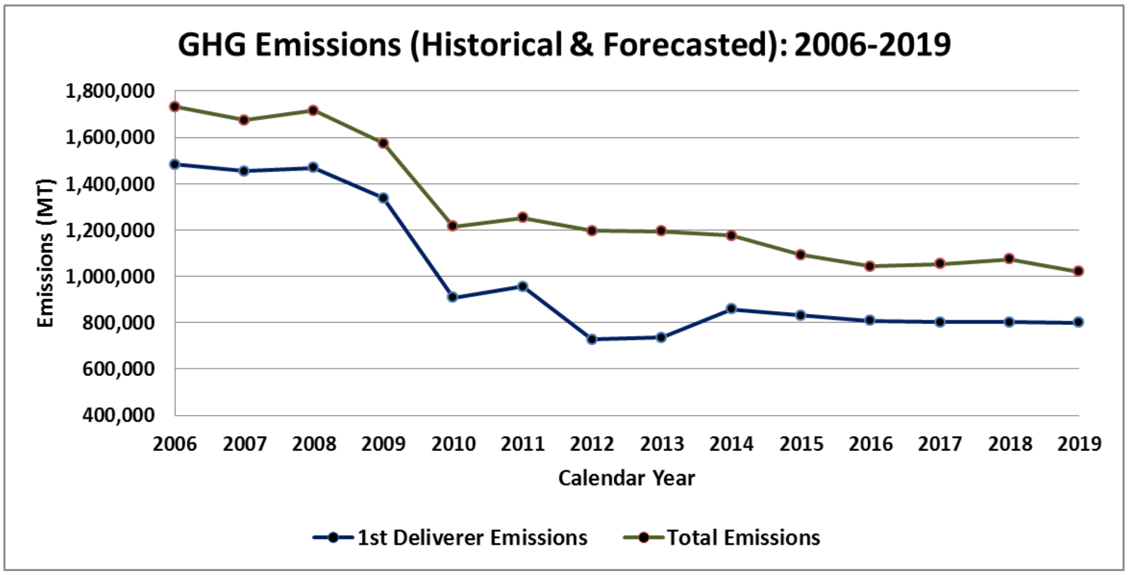


Figure 8.7.2. Historical and forecasted RPU carbon emissions: calendar years 2006-2019.

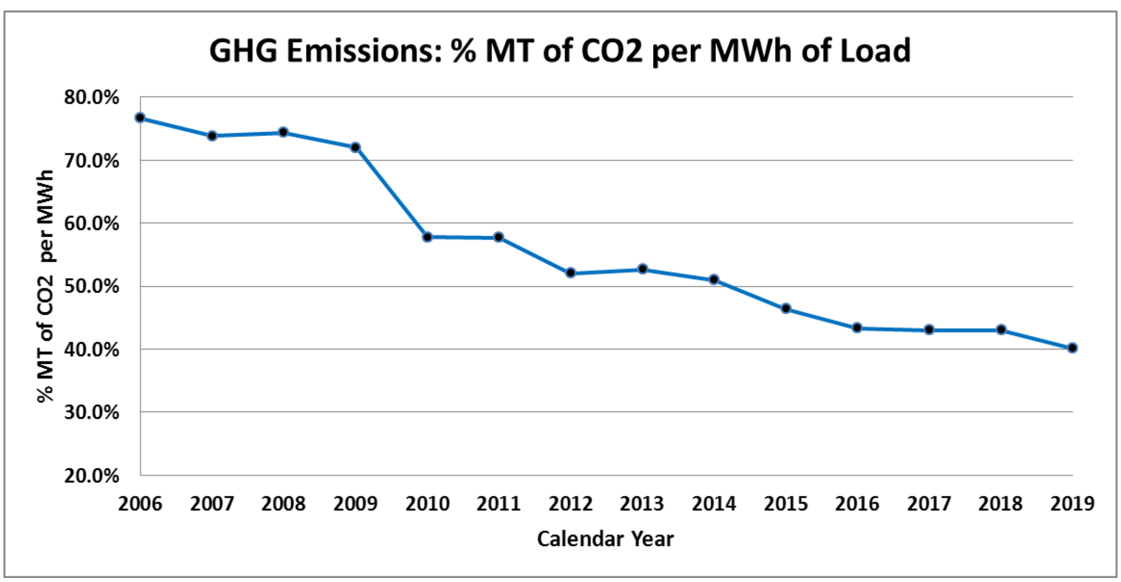


Figure 8.7.3. RPU "load normalized" carbon emission profile (metric tons of emissions per MWh of system load).

8.8 Five Year Budget Forecasts

All of the previously discussed power resource components play an important role in determining our overall power resource budget projections. Since a number of these forecasts are dependent on current CAISO market conditions, RPU has implemented a dynamically updated budget forecasting tool into the Ascend software platform. This forecasting tool produces updated Power Resources budget projections on a weekly basis, in order to reflect the latest market price forecasts and generation stack conditions.

Table 8.8.1 presents a summary of our FY15/16 through FY19/20 budget forecasts, as of December 26, 2014. (These are the forecasts that were submitted into the most recent RPU FY15/16 budget cycle.) As shown in Table 8.8.1, our FY15/16 net cost is projected to decrease by approximately 3.5 million dollars over the prior year's FY14/15 forecasts; this decrease is primarily due to the beginning of decommissioning activities of the SONGS generation facility. Beyond FY15/16, our overall Power Resource budget costs are currently forecasted to increase by 6 to 10 million dollars per year (through FY19/20), due to the simultaneous impact of rising CAISO transmission, energy and capacity costs.

Table 8.8.1. Five year forward power resource budget forecasts: fiscal years 15/16 through 19/20. Previous FY14/15 forecasts produced in December 2013; all forecasts shown in $1000 units.

	FY 2014/2015	FY 2015/2016	FY 2016/2017	FY 2017/2018	FY 2018/2019	FY 2019/2020
Summary						
Gross Costs	$ 204,983	$ 202,628	$ 211,896	$ 218,017	$ 231,411	$ 237,708
Gross Revenue	$ (35,000)	$ (36,154)	$ (36,420)	$ (36,743)	$ (37,070)	$ (37,399)
Net Costs	$ 169,983	$ 166,474	$ 175,476	$ 181,274	$ 194,341	$ 200,309
Summary						
Transmission	$ 57,821	$ 57,676	$ 60,188	$ 62,863	$ 64,127	$ 66,758
Energy	$ 90,459	$ 100,020	$ 106,682	$ 111,974	$ 119,562	$ 125,542
Capacity	$ 41,617	$ 35,547	$ 36,488	$ 34,549	$ 39,087	$ 40,026
SONGS	$ 8,781	$ 3,545	$ 3,545	$ 3,545	$ 3,545	$ -
GHG Regulatory Fees	$ 261	$ 250	$ 250	$ 250	$ 250	$ 250
Amendment 60 Settlement	$ -	$ -	$ -	$ -	$ -	$ -
Contingency Generating Plants	$ 2,200	$ 2,200	$ 2,200	$ 2,200	$ 2,200	$ 2,200
Gas Burns + Net Hedge Cost or (Revenue)	$ 3,844	$ 3,391	$ 2,542	$ 2,636	$ 2,640	$ 2,932
SUBTOTAL COST	$ 204,983	$ 202,628	$ 211,896	$ 218,017	$ 231,411	$ 237,708
CO2 Allowance Auction Revenue	$ (4,000)	$ (4,154)	$ (4,100)	$ (4,100)	$ (4,100)	$ (4,100)
TRR Revenue	$ (31,000)	$ (32,000)	$ (32,320)	$ (32,643)	$ (32,970)	$ (33,299)
SUBTOTAL REVENUE	$ (35,000)	$ (36,154)	$ (36,420)	$ (36,743)	$ (37,070)	$ (37,399)
TOTAL	$ 169,983	$ 166,474	$ 175,476	$ 181,274	$ 194,341	$ 200,309
Summary (Cost/Gross Load)						
Adjusted Transmission	$ 11.51	$ 10.82	$ 11.61	$ 12.41	$ 12.61	$ 13.31
Energy	$ 38.83	$ 42.16	$ 44.45	$ 45.99	$ 48.38	$ 49.93
Capacity	$ 17.87	$ 14.98	$ 15.20	$ 14.19	$ 15.82	$ 15.92
SONGs	$ 3.77	$ 1.49	$ 1.48	$ 1.46	$ 1.43	$ -
Total (all categories)	$ 72.97	$ 70.16	$ 73.11	$ 74.45	$ 78.64	$ 79.66

The full five year forward budget forecast is presented in Appendix D. These forecasts include detailed projections of our various Capacity costs, SONGS related costs, Transmission related costs and revenues, generation energy and associated energy costs and revenues, wholesale CAISO sales and purchases, CO2 emissions and net allocation revenues, fuel costs, and net hedging costs, respectively.

8.9 Summary of Results

Based on the forecast data presented in this Chapter, the following conclusions can be drawn concerning RPU's intermediate term resource positions.

- RPU can expect to have enough firm capacity to meet 100% of our forecasted system peak for each month in 2015. However, there will not be enough firm capacity to meet the 115% CAISO RA requirements during the Q3 2015 summer months. Additionally, in the absence of additional RA credit for our Hoover contract extension and new CalEnergy geothermal resources, RPU will not have enough firm capacity credit to meet 100% of our forecasted Q3 summer system peaks on/after 2016. Under the current CAISO RA paradigm, RPU should anticipate spending approximately 6.9 million dollars for system RA purchases to fill this gap. It should be noted that this shortfall will be significantly reduced if the CAISO elects to grant RPU capacity import allocation credits for the above mentioned Hoover and CalEnergy contracts.

- Notwithstanding point one above, the CAISO is currently proposing a new flexible RA paradigm under its current FRAC/MOO proposal. Unfortunately, staff does not yet have sufficient information to fully quantify the cost impacts of the new FRAC/MOO market design. However, it is reasonable to expect that these costs will be at least as high as RPU's cost under the current RA paradigm, and potentially much higher if our LM6000 RERC units do not fully qualify as Category 1 flexible RA resources. The FRAC/MOO paradigm potentially represents RPU's single greatest financial exposure over the next three-to-five years.

- RPU is on track to procure additional excess renewable energy, above and beyond our minimum mandated amounts. Some additional TRECs and/or Category-2 renewable energy products will need to be purchased in 2015 to help us meet our 20% 2015 RPS goal, but we should begin accumulating excess renewable energy credits on/after 2016. RPU is well positioned to achieve a 36% to 37% RPS target by 2019 and maintain this level at least through 2023 (via additional short-term TREC purchases), should upper-management choose to do so.

- RPU has about 80% to 85% of its load serving needs naturally hedged through long-term PPAs and generation ownership agreements. The remaining 15% to 20% of open energy positions need to be actively hedged via forward market purchases of energy and/or natural gas (the latter being used to hedge our internal generation production). Most of the remaining open energy volumes are associated with June-October HL time periods (particularly Q3 HL), and with March-April outage events. RPU's current expected costs to fully close these open HL positions range from 8.9 to 13.7 million dollars annually in the 2015-2019 timeframe. The associated CAR metrics for the same time period currently range from 3.9 to 8.2 million dollars, respectively.

- RPU needs to further increase its hedged positions for 2015, in order to achieve a minimum 95% hedging percentage as mandated by the RMC. Also, RPU may wish to consider a multi-year Q3 HL product, given the fact that current SP15 power prices are relatively inexpensive.

- Alternatively (or concurrently), RPU could further increase its renewable energy percentage by purchasing a structured, multi-year, firmed-and-shaped Q3 RPS product. Such a product could simultaneously provide additional hedging protection to the portfolio, since the energy from this firmed-and-shaped product could be concurrently used to meet Q3 load serving needs.

- RPU is expected to have more than enough Carbon allowances to fully meet its direct emission compliance needs through 2020. We currently forecast an excess allowance balance of approximately 267,000 to 304,000 credits annually. These are expected to be monetized through the CARB quarterly auction process, with most of the proceeds used to help offset RPU's incremental renewable energy costs.

- RPU's FY15/16 net portfolio cost is projected to decrease by approximately 3.5 million dollars over the prior year's FY14/15 forecasts; this decrease is primarily due to the SONGS generation facility decommissioning activities. Beyond FY15/16, our overall Power Resource budget costs are currently forecasted to increase by 6 to 10 million dollars per year (through FY19/20), due to the simultaneous impact of rising CAISO transmission, energy and capacity costs.

In summary, RPU is reasonably well positioned to meet its load serving needs over the next five years while minimizing the forecasted increase in its internal portfolio costs. RPU's CAISO market costs could be further significantly impacted under the new FRAC/MOO proposal; our staff remains actively engaged in the FRAC/MOO stakeholder process to minimize these RA related cost impacts. With respect to energy needs, some additional systematic forward hedging activities are required to maintain cash flow stability. Additionally, some opportunities still exist for further renewable or thermal resource procurement, specifically during Q3 summer months.

9. Long Term Forecasts: Future Capacity and Renewable Energy Needs

This chapter outlines RPU's longer term future capacity and renewable energy needs; i.e., our projected needs for the next twenty-year time horizon. Ultimately, these needs will be primarily influenced by our future load growth rates and the termination date of our 136 MW IPP Coal contract. However, our future capacity needs will also be significantly impacted by the CAISO RA paradigm in the future, including the amount of RA credits we receive for resources that are not currently grandfathered (e.g. the new CalEnergy geothermal resource and Hoover resource under the new contract), and the type of resources that would count as RA resources to satisfy CAISO's reliability needs in the future. Likewise, our renewable energy needs may also be strongly influenced by potentially higher RPS mandates. All of these possibilities are discussed in greater detail below.

9.1 Long Term Capacity Needs (2014-2033 Time Horizon)

As discussed in section 8.1, based on the current CAISO RA paradigm, our additional capacity needs for the next five years will depend significantly on the amount of import RA credit we receive on our CalEnergy geothermal expansion and Hoover extension contracts. More importantly, our longer term needs will become significant once our IPP Power Sales Contract expires. Currently, Riverside is contractually obliged to receive energy and capacity under this contract through May 2027. LADWP is the operating agent of the IPP power plants and manages the scheduling of IPP energy for IPP participants including entities in Utah and California. LADWP has announced its intention to retire IPP power plant by no later than January 1, 2026. Additionally, it is possible that the IPP participants could be forced to shut down IPP power plants earlier, should the US EPA require the installation of significant additional emission control systems on the generating units. Therefore, from a long term resource planning perspective, it is prudent to plan for an early IPP contract termination date (specifically, January 1, 2026), with the added possibility of an accelerated retirement schedule (occurring as early as January 1, 2021). This in turn implies that RPU could face a 136 MW capacity and energy deficit as early as January 2021; but certainly no later than January 2026.

Figure 9.1.1 shows a graph of this projected capacity shortfall, assuming (a) strong peak growth (see Table 2.8.1), (b) full RA credit for our Hoover extension and CalEnergy expansion contracts, and (c) that the IPP coal plant stays in service until January 2026. It is worthwhile to note that multi-month capacity shortfalls become apparent in the summer as early as 2022 under this strong peak growth scenario. However, after IPP retires, there is clearly insufficient capacity left in RPU's resource portfolio to meet our expected system peaks <u>during any month of the year</u>.

However, RPU's long term projected capacity shortfalls are not exclusively limited to the uncertainty surrounding our IPP resource. There is also considerable uncertainty over the future CAISO RA paradigm. A known issue for RPU under the current RA paradigm is the uncertainty of receiving additional intertie allocation for RA purposes for imported resources that are not currently grandfathered. Currently, CAISO allocates intertie allocation on an annual basis using a peak load ratio methodology after taking into account all the grandfathered resources an entity already has. Riverside's grandfathered RA resources significantly exceed our CAISO assigned maximum peak load ratio, and we do not expect to be allocated additional intertie rights until our IPP contract terminates. Additionally, under the current CAISO paradigm, there is no certainty that RPU can bi-laterally purchase sufficient additional intertie allocations for our newly (re)contracted resources. This uncertainty impacts RPU's new CalEnergy geothermal resource beginning February 2016, and our Hoover resource after the current Hoover contract expires in September 2017.

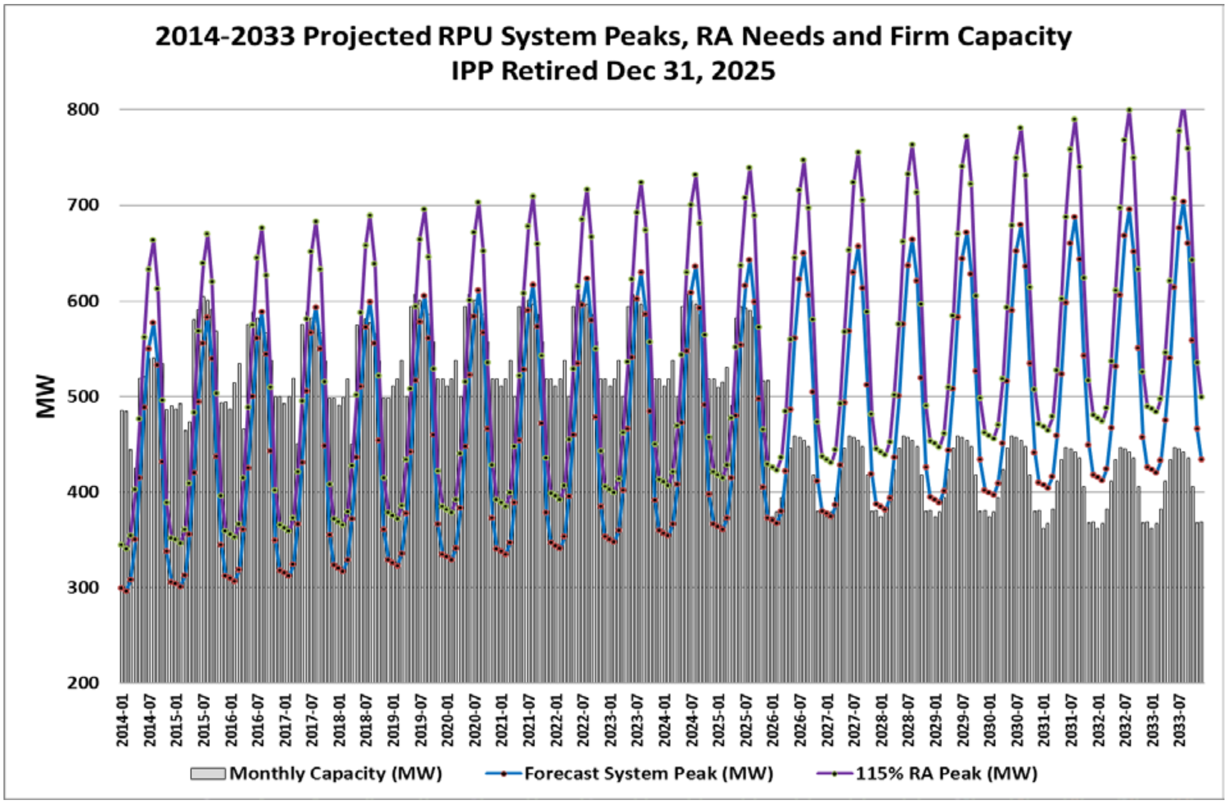


Figure 9.1.1. Projected future capacity shortfall under the strong peak growth assumption, assuming that the IPP coal plants retire in January 2026.

Our CalEnergy contract expansion begins in February 2016 (20 MW), increasing to 40 MW in January 2019 and 86 MW in June 2020. Likewise, our Hoover contract extension begins in October 2017; Hoover currently supplies between 20 to 30 MW of firm capacity to Riverside each month (see Table 3.1.2). Figure 9.1.2 shows the combined effect that the worst-case, no RA scenario has on our forecasted monthly capacity amounts, again under the strong peak growth assumption and assuming that the IPP coal plants retire in January 2026. As shown in Figure 9.1.2, significant capacity shortfalls begin showing up in 2018, turning into substantial shortfalls on/after June 2020.

Figure 9.1.3 shows the total amount of future RPU capacity in question for the 2014-2033 timeframe. The monthly IPP capacity lost on/after 2026 is shown in red, while the capacity amount shown in orange represents potential losses due to an accelerated IPP retirement schedule. The Hoover and CalEnergy capacity amounts associated with their corresponding contract extensions are shown in gray. Under the current CAISO RA paradigm, Riverside will not automatically receive intertie allocations for these re-contracted resources until the IPP contract is terminated.

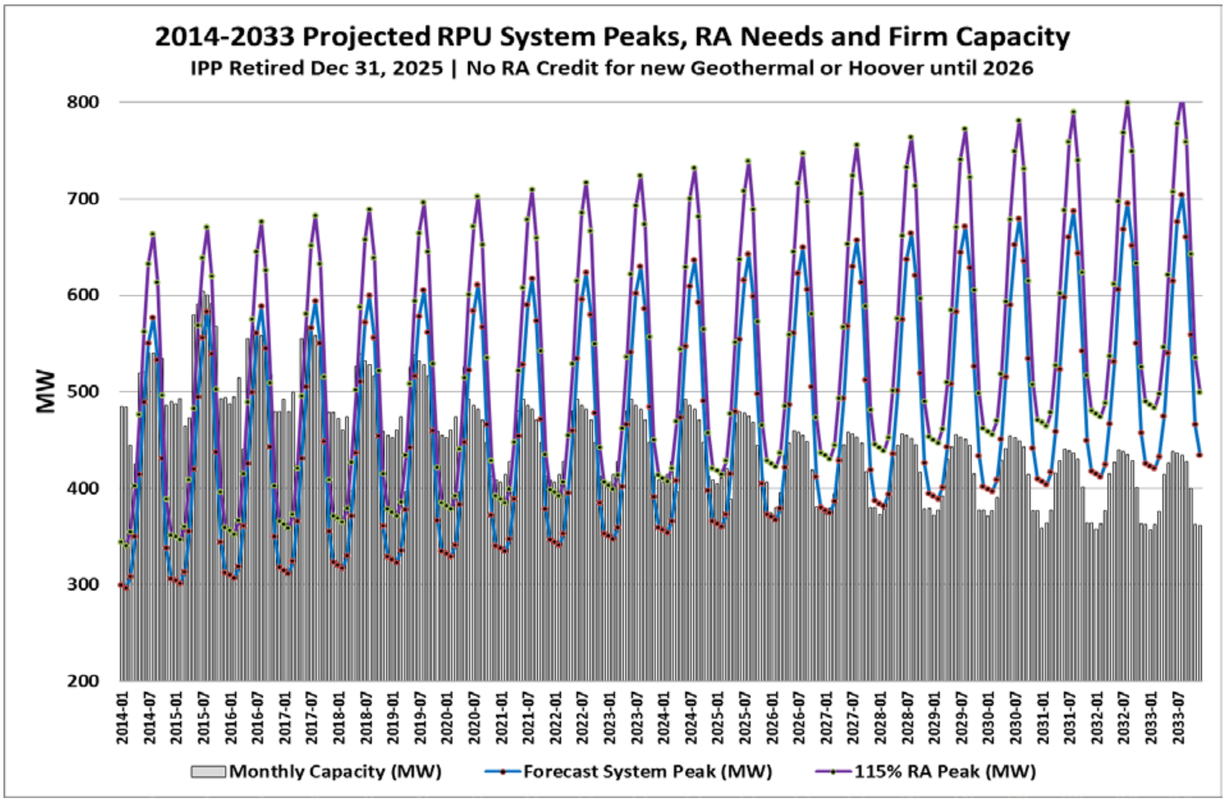


Figure 9.1.2. Projected future capacity shortfall (strong peak growth assumption), assuming the IPP coal plants retire in January 2026 and that RPU receives <u>no RA credit</u> for the Hoover and CalEnergy contract extensions.

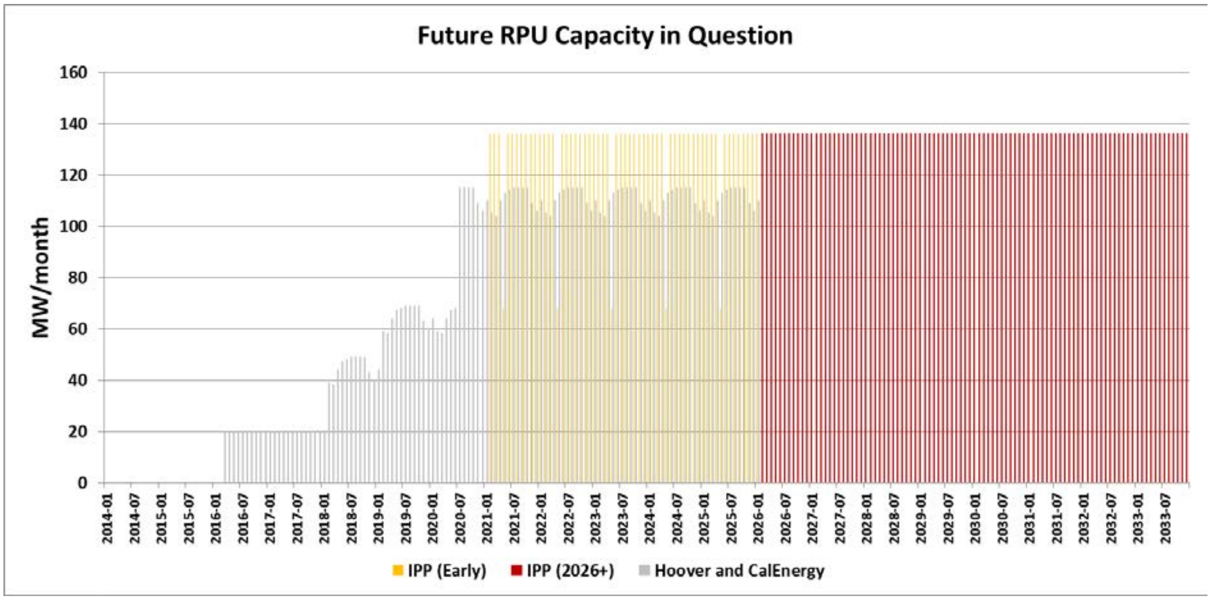


Figure 9.1.3. Future RPU capacity in question (IPP, CalEnergy and Hoover contracts).

The capacity and energy associated with our IPP contract will need to be replaced with one or more suitable alternative resources once this contract terminates. In Chapter 10 we will examine a number of alternative replacement options under two plausible replacement dates (January 2021 and January 2026, respectively), and examine the budgetary impacts under each alternative scenario. In contrast, in this IRP we assume that RPU will receive full RA credit for the capacity associated with the CalEnergy expansion and Hoover extension contracts (most likely by purchasing the necessary intertie allocations via bilateral transactions). Table 9.1.1 quantifies the monetary value of this RA credit, based on the 2014 system RA costs shown previously in Table 6.6.1, and assuming an annual 3% cost escalation rate. Note that by 2021 the RA value associated with these two contracts is estimated to be 2.7 million dollars; by 2025 this value will increase to nearly 3.1 million dollars. The combined value of this RA credit is forecasted to be potentially greater than 20 million dollars, assuming that the IPP contract remains in place through 2025. It is clear that having the certainty of the RA value of RPU's new resources is of paramount importance. Therefore, RPU should proactively seek resolution of this issue either through the CAISO RA stakeholder process or via the pursuit of a different operational model in the CAISO markets that mitigates such uncertainty.

Table 9.1.1. Forecasted RA capacity value of the CalEnergy and Hoover contract extensions. Estimates based on $/kW-month RA costs shown in Table 6.6.1, assuming a 3% annual escalation rate.

Year	CalEnergy & Hoover Capacity Value (million $)
2014	0
2015	0
2016	0.40
2017	0.43
2018	1.04
2019	1.52
2020	2.45
2021	2.72
2022	2.80
2023	2.88
2024	2.97
2025	3.06
2026	0
Potential Total	**20.28**

It should also be noted that CAISO's RA paradigm is expected to change over time due to changing grid reliability needs. Therefore, the type of resources needed to maintain grid reliability and count for RA capacity are also likely to change. For example, the CAISO is concluding the FRAC/MOO stakeholder process to determine the additional operating characteristics of resources that will be needed in the future for renewable integration purposes (see section 5.2.3). Such operating characteristics will ultimately translate into the type of resources that can count as RA resources. Hence, there is no guarantee that RPU's existing and/or new resources will all qualify as RA resources in the future. Furthermore, the CAISO, in cooperation with CPUC, intends to soon initiate a new stakeholder process to address the long term capacity needs of the grid. The outcome of this process may define additional attributes that RA resources will need to have in the future.

All of this uncertainty will greatly influence and impact our future resource acquisition decisions, as well as the future operational model that RPU elects in the CAISO markets.

9.2 Long Term Renewable Energy Needs (2014-2033 Time Horizon)

In addition to capacity, Riverside will need to procure additional renewable energy resources in the latter part of the 2014-2033 time horizon to remain fully RPS compliant. The exact timing and amount of new renewable resources will depend upon a number of factors, two of the most important being our future load growth pattern and future changes to the RPS mandate (if any). For planning purposes, at least two load growth scenarios and up to three RPS mandates should be analyzed in order to gain a better idea of our potential future renewable energy needs and associated cost of service impacts.

Our two load growth scenarios have already been discussed in detail in Chapter 2 (see section 2.8 and specifically Table 2.8.1). An appropriate upper bound for a revised, post-2020 RPS mandate is more difficult to clearly delineate. Recently, there has been some discussion in the state legislature for imposing a new 50% mandate target, purportedly by 2030. However, the most current CAISO technical studies (and the just published E3 RPS study) suggest that such a goal will be technically infeasible. Such a target can only be reached if significant investments are made to both the grid and various supporting technologies, such as energy storage, demand response and new fast-ramping thermal generation. Therefore, we have chosen to examine the RPS mandate in two separate analyses in this IRP.

In Chapter 10, we first examine the more realistic 40% RPS by 2030 scenario to represent the alternative (and more aggressive) renewable energy mandate, for comparison to the 33% base case. This first analysis facilitates a reasonable "base case versus alternative" comparison that can be used to help quantify the cost impacts of a 40% mandate, under both strong and weak load growth assumptions. However, in Chapter 12, we examine both 40% and 50% RPS by 2030 mandates with respect to the 33% RPS base case, and re-analyze all of these studies under strong load growth and alternative (and significantly higher) pricing structures. Hence, Chapter 12 presents a comprehensive overview of a broad range of potential RPS cost impacts, while Chapter 10 focuses more narrowly on quantifying the cost impacts of our most realistic, alternative RPS scenario.

Table 9.2.1 shows the annual, minimum post-2020 RPS targets for the two alternative RPS mandates considered in this IRP analysis. Note that the 33% RPS base case consists of a constant 33% target from 2020 through 2033.

Table 9.2.1. Alternative RPS mandate for the 2020-2033 timeframe.

Mandate	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031+
40% RPS	33%	33%	33%	33%	34%	35%	36%	37%	38%	39%	40%	40%
50% RPS	33%	34.7%	36.4%	38.1%	39.8%	41.5%	43.2%	44.9%	46.6%	48.3%	50%	50%

Under the recently enacted SB X1-2 RPS mandate, all California LSEs are required to procure at least 75% of their renewable energy from Portfolio Content Category 1 (PCC-1) renewable resources (essentially, in-state resources) and no more than 10% can be from PCC-3 TREC's. The remainder of the renewable energy procurement can come from PCC-2 firmed-and-shaped energy transactions. However, to date, RPU's long-term RPS strategy has been to consider only PCC-1 and PCC-3 products, especially since the price differential between PCC-1 and PCC-2 products has diminished in recent years.

Thus, assuming this strategy is continued, Riverside should plan to procure enough additional PCC-1 renewable energy resources to meet at least 90% of its post-2020 RPS mandate.

Given the aforementioned assumptions, it is possible to project the amount and timing of additional PCC-1 renewable resources that are needed to meet either the base or alternative RPS mandates, under either load growth scenario. Projecting the specific renewable technology type is more difficult, given the significant uncertainty in future market pricing and technology developments. For these projections, we have instead assumed that Riverside would try to procure a blended mixture of new (generic) geothermal, wind and/or solar resources to satisfy the appropriate RPS mandate in effect. We have also assumed that Riverside would want to procure a slight excess renewable buffer, approximately 60 GWh per year, in order to prudently account for unanticipated energy curtailments and/or project delays, etc.

Figure 9.2.1 through 9.2.5 show the amounts and timing of additional renewable energy procurement that Riverside should plan for, under the various RPS mandates and load growth scenarios examined in this IRP. The proposed annual capacity amounts associated with each generic resource are presented in Table 9.2.2 for these same mandate/growth scenarios. Likewise, the total new renewable energy volumes associated with each scenario are presented in Table 9.2.3. Note that no new renewable resources need to be procured before 2033 to meet the 33% baseline RPS mandate under the weak load growth assumption. As Figures 9.2.1, 9.2.3, 9.2.4 and 9.2.5 show, Riverside will need to procure additional renewable resources in the latter part of the 2014-2033 timeframe in order to remain within full RPS compliance under each respective scenario. However, with the exception of the 40% RPS and 50% RPS mandates under the strong load growth scenario, our additional renewable procurement needs are forecasted to be fairly minimal.

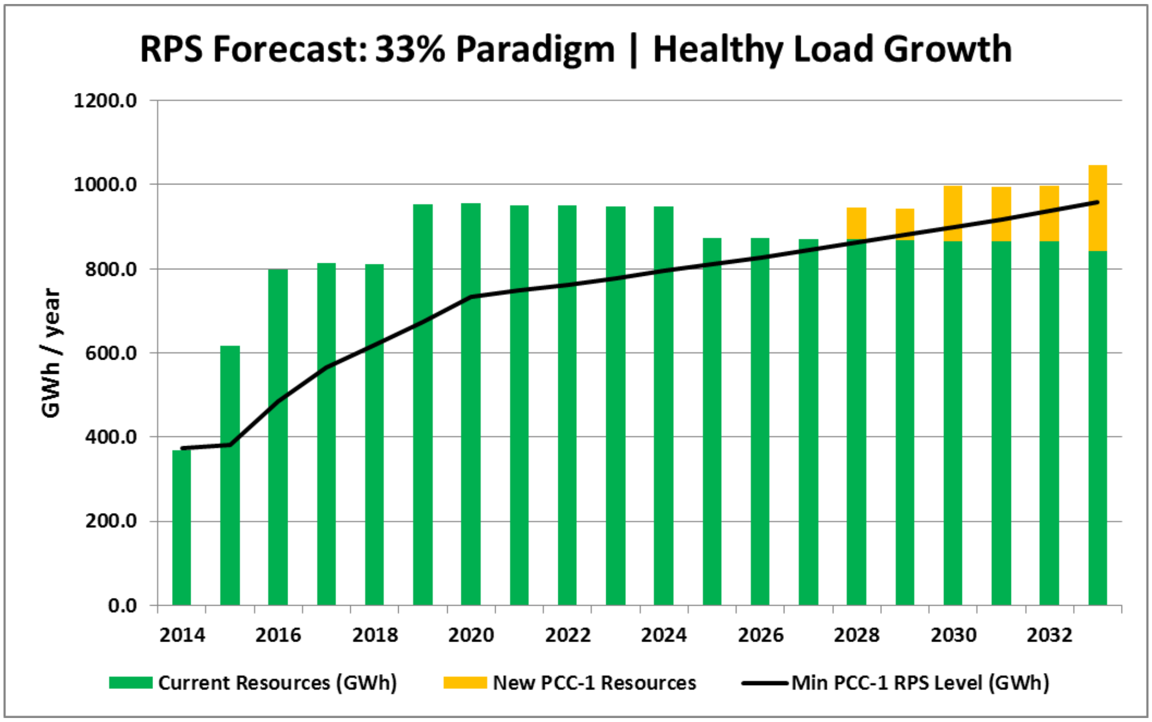


Figure 9.2.1. New PCC-1 resource needs for the 33% RPS | strong load growth scenario.

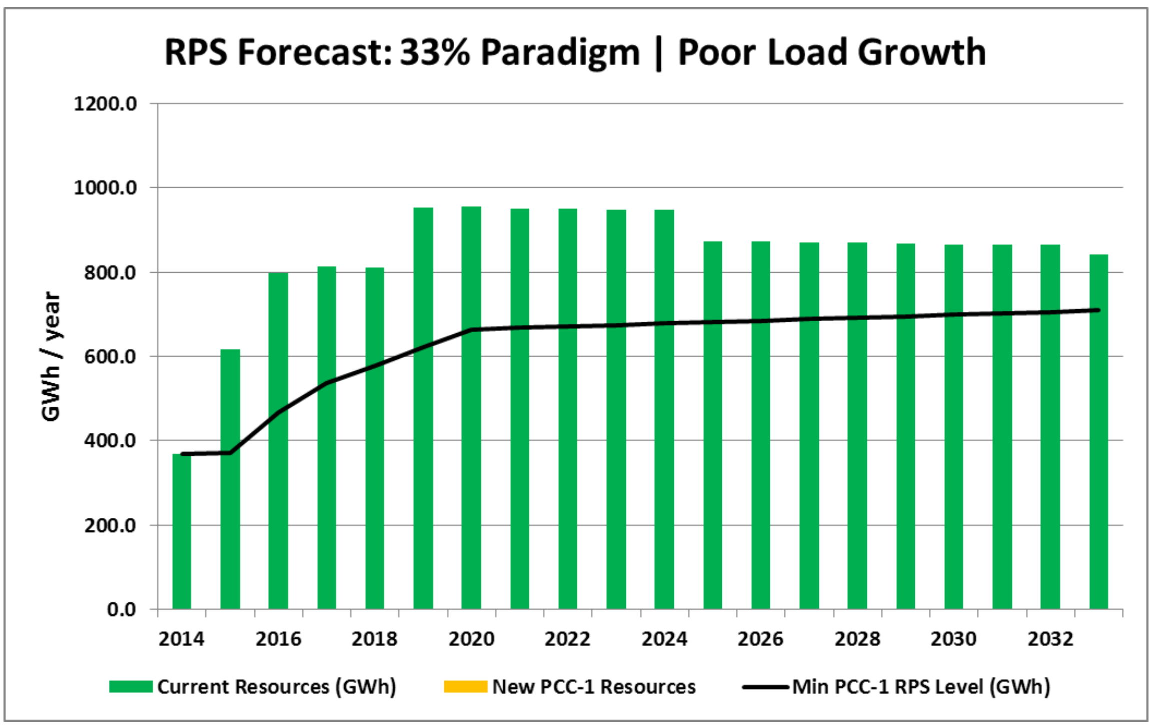


Figure 9.2.2. New PCC-1 resource needs for the 33% RPS | weak load growth scenario.

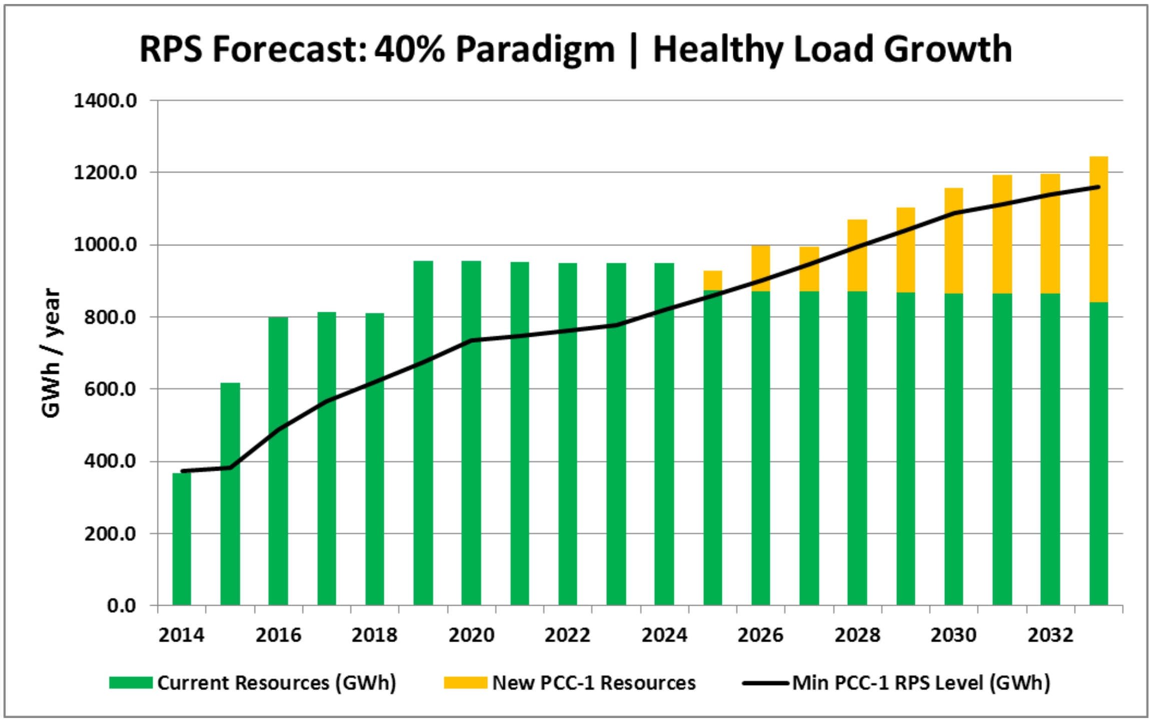


Figure 9.2.3. New PCC-1 resource needs for the 40% RPS | strong load growth scenario.

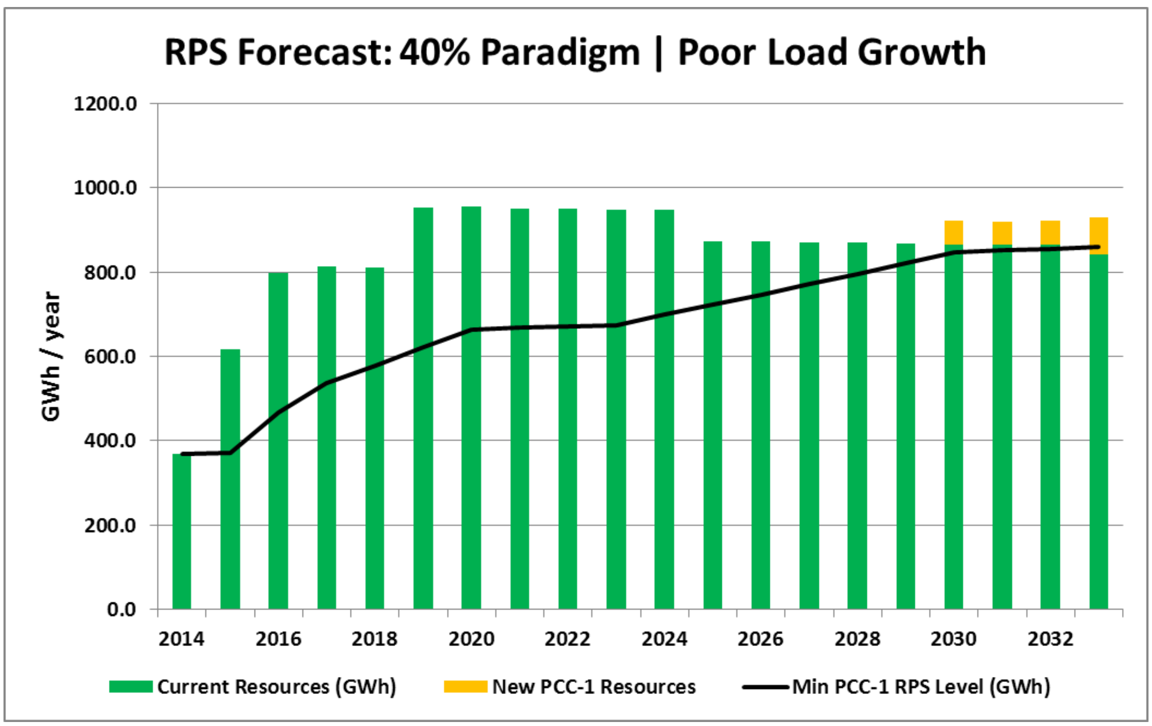


Figure 9.2.4. New PCC-1 resource needs for the 40% RPS | weak load growth scenario.

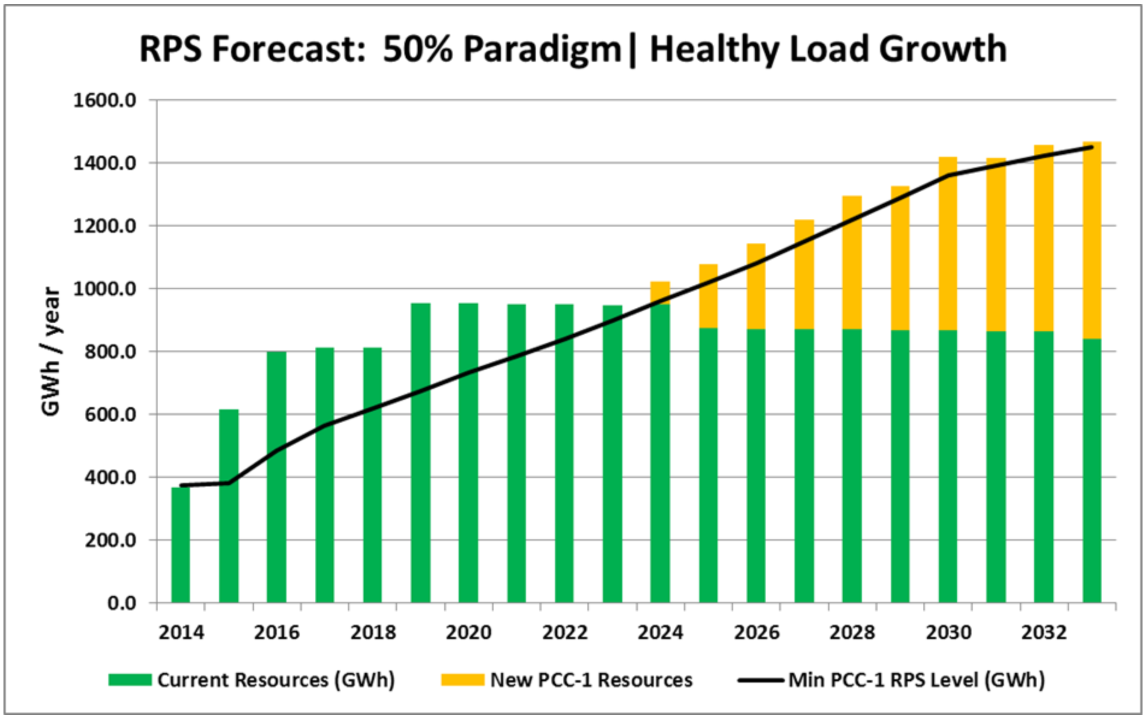


Figure 9.2.5. New PCC-1 resource needs for the 50% RPS | strong load growth scenario.

Table 9.2.2. Generic geothermal (Geo), wind and solar capacity additions for each RPS | load growth scenario.

Scenario	Resource Type	MW Capacity Amounts (assumed CF's are 85%, 39% and 32% for Geo, Wind and Solar)									
		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
33% RPS Strong LG	Geo	-	-	-	-	10	10	10	10	10	20
	Wind	-	-	-	-	-	-	-	-	-	-
	Solar	-	-	-	-	-	-	20	20	20	20
40% RPS Strong LG	Geo	-	-	-	-	10	15	15	20	20	30
	Wind	-	-	20	20	20	20	20	20	20	20
	Solar	-	20	20	20	20	20	40	40	40	40
40% RPS Weak LG	Geo	-	-	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-	-	10
	Solar	-	-	-	-	-	-	20	20	20	20
50% RPS Strong LG	Geo	10	20	20	30	40	45	50	50	55	60
	Wind	-	-	20	20	20	20	20	20	20	20
	Solar	-	20	20	20	20	20	40	40	40	40

Table 9.2.3. Corresponding annual renewable energy additions for each RPS | load growth scenario (i.e., energy amounts associated with the capacity expansions shown in Table 9.2.2).

Scenario	GWh Renewable Energy Amounts (for all resource types)									
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
33% RPS Strong LG	0	0	0	0	74.7	74.5	130.3	130.3	130.7	204.8
40% RPS Strong LG	0	55.9	124.2	124.2	199.2	235.9	291.8	329.0	329.9	403.5
40% RPS Weak LG	0	0	0	0	0	0	55.9	55.9	56.0	90.1
50% RPS Strong LG	74.7	204.8	273.1	347.6	423.2	459.3	552.4	552.4	591.3	626.9

9.3 Plausible Long Term IRP Scenarios (2014-2033 Time Horizon)

As mentioned above, our two load growth scenarios have already been discussed in detail in Chapter 2. Likewise, the previous two sections have outlined three reasonable future RPS scenarios and two potential IPP contract end dates. In Chapter 10, we will examine the 33% and 40% RPS scenarios together with the two load growth scenarios and two IPP contract end dates in order to yield eight plausible, primary resource planning scenarios that RPU should examine and prepare for. These scenarios will represent our most plausible potential future states, before factoring in and examining different IPP replacement options. (Various IPP replacement options will be examined in detail in Chapter 11.)

In the next chapter we will examine the projected budgetary impacts of these eight scenarios, in conjunction with unhedged and hedged (post-IPP replacement) market purchases. This budgetary assessment will consider both the expected values and simulated standard deviations of our fully loaded RPU system costs; i.e., our projected annual load serving costs and their associated portfolio risk metrics. The goals of this simulation analyses are multifold, but primarily focused towards determining a cost effective, minimal risk forward RPU procurement strategy; i.e., a strategy that can facilitate the eventual replacement of IPP while meeting our expected load serving needs for the next twenty years.

10. Long Term (Twenty Year Forward) Portfolio Analyses

As discussed in Chapter 9, eight plausible resource planning scenarios can be identified that describe the range of combinations of two potential future load growth patterns, RPS mandates, and IPP contract termination dates. In this chapter we examine the projected budgetary impacts of these different scenarios, in conjunction with unhedged and hedged market purchases. This budgetary assessment considers both the expected values and simulated standard deviations of our fully loaded cost of service. Our fundamental modeling inputs and assumptions are discussed in detail in sections 10.1 and 10.2, respectively. The impacts of each fundamental input assumption are then examined in sections 10.3 through 10.6, specifically with respect to our expected cost of service and associated cost uncertainty over the next twenty year time horizon.

High-level Summary of Results

Before delving into the considerable details concerning our modeling inputs, assumptions and analyses, it will be useful to briefly summarize the pertinent finding of these studies. The panel graph shown in Figure 10.1 shows the expected, load normalized cost of service (COS_{LN}) estimates in 2023 and 2033 for the twelve resource planning scenarios examined here (i.e., our eight primary scenarios plus four additional scenarios where we've used hedged market purchases to replace our lost IPP power). Note that the twelve scenarios have been ordered by their 2023 COS_{LN} estimates (from high to low). In addition to each estimate (shown as black diamonds), two standard deviations of uncertainty are also shown (blue and green horizontal bars, respectively); these bars define the range of uncertainty associated with each COS_{LN} estimate. As shown in Figure 10.1, our long term load growth projections represent the single greatest driver of our ultimate cost of service, while our hedging strategy represents the primary factor influencing the associated COS_{LN} uncertainty estimates.

The panel graph shown in Figure 10.2 further quantifies and summarizes these scenario simulation results. The upper panel plot shows how much each studied factor adds to our baseline COS_{LN} costs in 2023, 2028 and 2033, while the lower panel plot quantifies the corresponding uncertainty effects (standard deviations) associated with these same factors. As shown in the upper panel plot, if RPU were to experience weak load growth over the next ten to twenty years, we should expect our COS_{LN} to increase by 1 to 2 ₵/kWh over this same time horizon. This is by far the single greatest influencing factor in determining our future COS_{LN} estimates; note the next largest impact is associated with an early IPP termination date (~ 0.5 ₵/kWh impact). In contrast, maintaining a 40% RPS and/or replacing IPP energy with hedged market purchases add relatively little to our forecasted future COS_{LN} estimates. Similar information is summarized in the lower panel plot, abet here with respect to the associated COS_{LN} uncertainty estimates. Note that while adopting a viable hedging paradigm adds little to our expected COS_{LN}, it greatly reduces the associated uncertainty around these estimates. The 40% RPS scenario also slightly reduces our COS_{LN} uncertainty estimates (as does weak load growth), although both of these impacts are relatively minor.

All of these results are summarized in much greater detail in sections 10.3 through 10.5, respectively. Additionally, in section 10.6 we will examine the sensitivity of a selected set of our future unhedged and hedged resource portfolios to significant market price shocks.

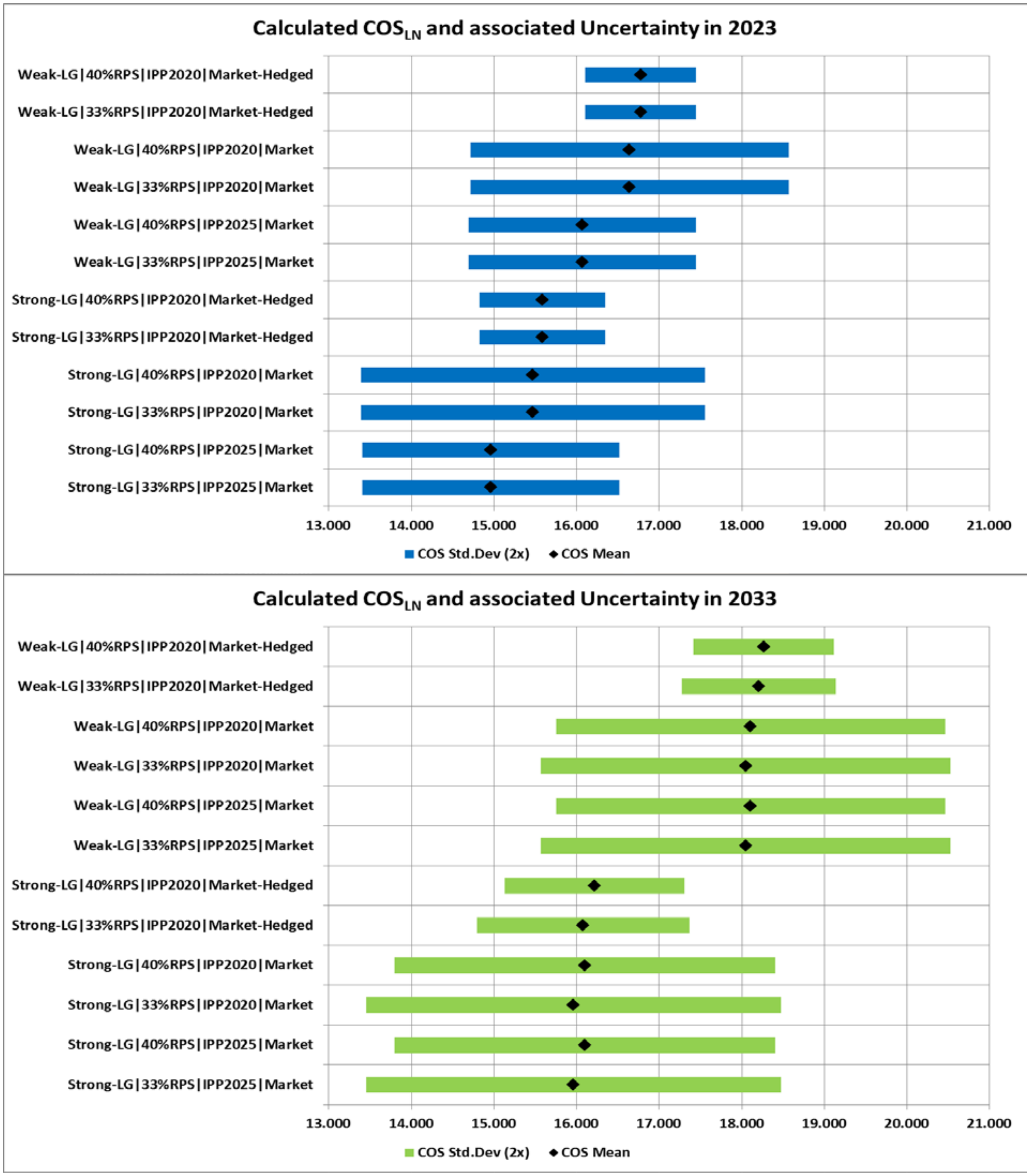


Figure 10.1. Panel plots of forecasted COS_{LN} and associated uncertainty (± 2 standard deviations) in 2023 (upper plot) and 2033 (lower plot).

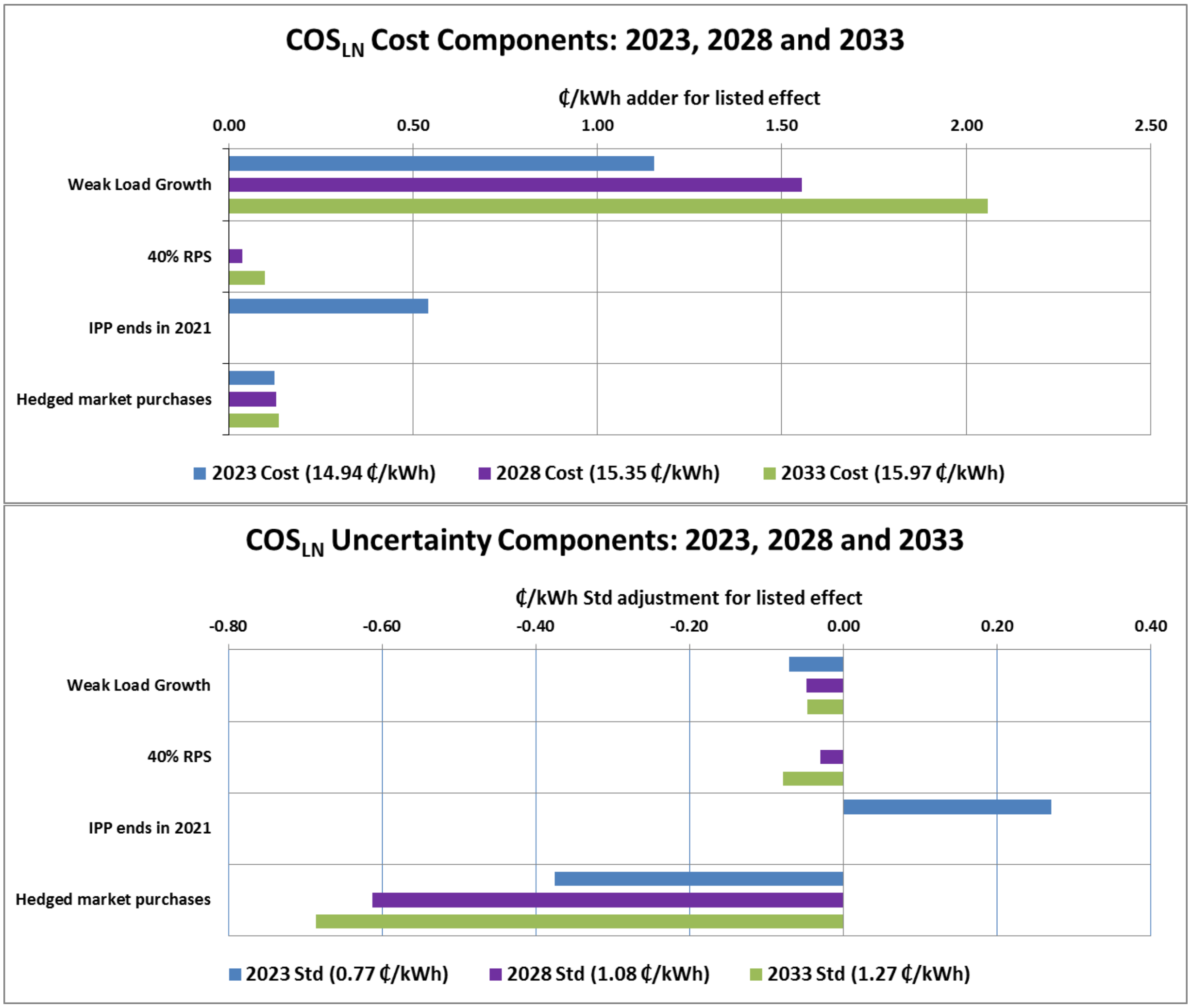


Figure 10.2. Panel plots of the calculated COS_{LN} components (expected costs and associated standard deviations) for the four primary input factors; estimates shown for years 2023, 2028 and 2033.

10.1 Modeling Inputs and Assumptions

All of the scenario studies examined here have been simulated using the Ascend software platform. Our long-term load and price inputs are discussed in Chapters 2 and 7, respectively. Likewise, our RPS mandates and IPP end-date scenarios are described in Chapter 9. With respect to the limited IPP replacement options considered in this chapter, we have examined scenarios where our IPP coal contract is replaced with 150 MW of long-term hedged energy contracts and compared these results to a no-replacement, open-market option. (In this latter option, RPU would simply replace the long-term IPP contract with short-term day-ahead energy purchases in the SP15 market.)

Table 10.1.1 lists the twelve different forward portfolio scenarios that are studied in detail in this chapter. As shown in Table 10.1.1, we have examined the hedged energy replacement option only for the December 31 2020 IPP contract end-date. Note that it is not particularly informative to run a hedged energy scenario for the later end-date, since the earlier end-date scenario already covers the later date range. Additionally, we assumed that all hedged energy contracts were purchased at the current expected future market prices, plus a 4% price adder. This latter price adder accounts for a reasonable amount of future market price uncertainty, assuming RPU were to implement a multi-year, layered hedging approach to replace lost IPP energy.

With respect to modeling the various costs associated with the early termination of our IPP contract, two different approaches can be employed. First, one could assume that the generation asset is voluntarily shut down early by all parties involved in the contract, in which case only the debt service payments (if any) remain on the books. Or alternatively, one could instead assume that Riverside unilaterally elects to replace our IPP energy with a different generation asset, but while doing so is still unable to avoid its minimum IPP generation O&M costs until 2027. While both approaches have merit, we have elected to model the second scenario in order to better understand our maximum possible cost impacts from an early termination date. We believe that this assumption is appropriate for these IRP analyses, since it is more conservative. However, it should be noted that the early termination cost impacts quantified in these subsequent studies could be significantly reduced under an early voluntary retirement agreement.

It should also be noted that 100 simulation runs have been performed for each scenario shown in Table 10.1.1. These simulations allow us to not only quantify the expected annual load serving costs associated with each portfolio scenario, but also the associated uncertainty (i.e., standard deviation) surrounding these cost estimates. Essentially, these standard deviations can be used to derive the "cost at risk" associated with each portfolio scenario. Conceptually, scenarios with lower expected load serving costs and associated standard deviations should be preferred, since the ultimate cost of any given future scenario can never be perfectly forecast.

Each of the 100 Ascend simulation runs associated with each scenario were performed at the hourly granularity over the same twenty year timeframe (January 1, 2014 through December 31, 2033), using the same set of input forward price curves. (Note that the input forward price curves define the normalized mean of the simulated forward price data for each scenario, respectively.) The corresponding total net portfolio costs (TNPC) were then summarized at the annual level for each simulation run and in turn used to compute the expected net portfolio costs and associated standard errors for each scenario. The TNPC variable is defined as

$$\text{TNPC} = \text{TGC} + \text{TLC} - \text{TGGR} - \text{HP(MtM)}$$

where the variables on the right hand side of this equation are defined as shown below.

- TGC: The total generation costs associated with all of the generation assets in the portfolio.
- TLC: The total cost for purchasing our system load (from the CAISO SP15 day-ahead market).
- TGGR: The total gross revenue received from selling all of the energy generated by our RPU portfolio back into the SP15 market.
- HP(MtM): The total payoff amount associated with all of our forward hedging instruments, computed on a mark-to-market basis.

Once determined, the TNPC variable was combined with our primary additional fixed budgetary costs, in order to determine the overall annual load serving costs under each specific scenario. These additional fixed costs are described in greater detail in section 10.2.

Table 10.1.1. Input variable levels used in each of the twelve different forward portfolio scenarios.

Scenario #	Load Growth	RPS Mandate	IPP End-date (Dec 31, 20XX)	IPP Replacement Option
1	Strong	33%	2020	Market Purchases
2	Strong	33%	2020	Hedged Market Purchases
3	Strong	33%	2025	Market Purchases
4	Strong	40%	2020	Market Purchases
5	Strong	40%	2020	Hedged Market Purchases
6	Strong	40%	2025	Market Purchases
7	Weak	33%	2020	Market Purchases
8	Weak	33%	2020	Hedged Market Purchases
9	Weak	33%	2025	Market Purchases
10	Weak	40%	2020	Market Purchases
11	Weak	40%	2020	Hedged Market Purchases
12	Weak	40%	2025	Market Purchases

10.2 Fixed Budgetary Costs and IRP Budget Assumptions

In addition to the calculation of the total net portfolio costs, a number of fixed budgetary costs (and revenues) must be properly specified in order to calculate future cost-of-service projections. The most important additional costs and revenues are as follows:

- SONGS: The cost obligations associated with winding down our SONGS contract and initializing the decommissioning process.
- CAISO Transmission costs: Our transmission costs, as determined by future CAISO Transmission Access Charge (TAC) rates.
- GHG/Carbon revenues: The revenues associated with the sale of allocated carbon emission credits, and the assumptions concerning the number of free allowances (if any) beyond 2020.
- Resource Adequacy (RA) costs: The cost assumptions surrounding our future RA purchases needed to satisfy the 115% CAISO RA paradigm.
- CAISO Uplift fees and other Power Resource costs: The ongoing costs associated with our CAISO energy and transmission uplift fees, CRR auction expenses, and internal generation facilities.

- Utility Personnel and O&M costs: RPU's "all-other" operational costs, not related to power supply activities.
- Long-term Debt Service costs: RPU's long-term Debt Service costs.
- General Fund Transfer (GFT) Fee: RPU's obligation to transfer 11.5% of its gross annual revenues to the City of Riverside.

Note that while a few of these costs are common across all of our simulated IRP scenarios (e.g., SONGs, Personnel and O&M, and Debt Service), most of these costs are a function of one or more of the IRP input variables.

More importantly, it should be recognized that all of these additional budgetary costs (with the possible exception of the GFT fee) have some degree of uncertainty associated with them. For modeling purposes, it is possible to specify approximate standard deviations for at least some of these additional costs. More specifically, we assume that the uncertainty components (i.e., standard deviations) associated with the following three additional budgetary costs are as follows:

- CAISO Transmission: Std.Dev = 10% of the annual TAC rate
- GHG/Carbon: Std.Dev = 30% of the annual CO_2 emission costs
- RA: Std.Dev = 10% of the annual RA purchase costs

The remaining budgetary costs are treated as fixed costs in the subsequent analyses, since reliable uncertainty estimates for these costs are not readily available and all of these costs (other than the GFT fee) are modeled as common costs across all simulated scenarios.

The input assumptions and methodologies used to forecast each of these additional cost components are described in more detail below.

10.2.1 SONGS Related Costs

Although the SONGS facility has been officially retired, SONGS-related cost obligations are still expected to be present in RPU's budget for at least the next five years. These cost obligations are expected to fall under the following expense categories:

- Professional services
- Outside legal services
- Decommissioning operations
- Operations and maintenance
- Insurance charges
- Decommissioning fund expense
- Taxes and assessments
- Capital costs related to decommissioning

Given that various SONGS proceedings related to the plant's retirement are still underway, official estimates of the ongoing cost have yet to be officially established. Therefore, we must make some assumptions about the amount and behavior of these SONGS costs going forward. In the fiscal year ending (FYE) 2015 budget, we have estimated our total SONGS related costs to be 10.4 million dollars. Beyond FYE 2015, SONGS costs ramp down under the assumption that decommissioning will begin by no later than January 1, 2016. As such, the Decommissioning operations and Decommissioning expense categories drop 50% in FYE 2016 and then disappear in FYE 2017. Likewise, the Operations and Maintenance expense category drops 50% in FYE 2017, and then disappears thereafter. The remaining expense categories carry on through FYE 2020 where they drop 50% and then disappear as of FYE 2021.

For the IRP analysis, RPU's total SONGS budget cost projections have been converted from a fiscal year to a calendar year basis through interpolation. RPU's total SONGS budget cost projections by calendar year are shown in Table 10.2.1 below. Note that these cost forecasts are common across all twelve IRP scenarios.

Table 10.2.1. Forecasted SONGS budget cost projections through CY 2020.

	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
SONGS Costs ($000)	13,267	8,876	5,271	2,536	1,891	1,410	470

10.2.2 CAISO Transmission Costs

As a Participating Transmission Owner (PTO) in the CAISO, RPU's transmission entitlements generate both costs and revenues. Our costs consist of three primary components: (a) the CAISO Transmission Access charge (TAC) rate, as it applies to our system load metrics, (b) various transmission service agreements associated with certain long-term resources, and (c) our debt service and O&M costs incurred from transmission project entitlements that were financed through the Southern California Public Power Authority (SCPPA). These latter two cost categories make up the major components of RPU's annual Transmission Revenue Requirement (TRR). However, because RPU transferred operational control of these transmission entitlements to the CAISO when it became a PTO on January 1, 2003, RPU is entitled to compensation from the CAISO grid users for recovery of its associated transmission costs through RPU's TRR. While typically not an exact match in practice, the CAISO TRR compensation and RPU's transmission cost incurred from its SCPPA transmission project entitlements and other transmission service agreements are sufficiently close enough to be netted out for budget forecasting purposes. As such, we have assumed that they directly offset one another in this IRP, leaving only the TAC cost flowing into the IRP's total budget cost calculation.

The CAISO TAC is a function of two components: (1) the CAISO TAC rate, which is a $/MWh charge assessed to LSE's who require access to the CAISO grid, and (2) the LSE's gross MWh load served via the CAISO grid. As a CAISO member, RPU incurs this TAC charge on its total MWh of gross load.

Thus, for any RPU load forecast, projecting RPU's TAC cost through the 2033 only requires a projection of the CAISO TAC rate. The CAISO has such a projection through 2026 in its 2012-2013 Transmission Access Charge Model, which is posted in the Transmission Planning Section on the CASIO website.

In the CAISO TAC Model, the TAC rate is derived by dividing the total revenue requirements to pay for high voltage transmission projects within the CAISO by the forecasted CAISO system gross load. Given projections of these parameters, the CAISO TAC Model shows TAC rates increasing about 4% annually through 2020 and then decreasing about 1% annually between 2021 and 2026. For this IRP, rather than carry the decreasing trend through to 2033, we have elected to use the CAISO projected TAC rates through 2024, where they approach $12/MWh, and then hold that amount constant through the end of the 2033 study horizon. Table 10.2.2 below shows the projected TAC rates used to calculate RPU's TAC costs associated with our two distinct ("strong" and "weak") system load growth forecasts.

Table 10.2.2. CAISO TAC rate projections through 2033; for use in computing RPU's TAC costs.

Year	TAC Rate ($/MWh)
2014	9.81
2015	10.27
2016	10.75
2017	11.04
2018	11.45
2019	11.90
2020	12.40
2021	12.32
2022	12.22
2023	12.12
2024	12.03
2025 – 2033	12.00

10.2.3 GHG Revenues

The Cap and Trade Program in California is well defined through 2020, and RPU is to receive the annual allocations of Carbon allowances shown in Table 10.2.3. The allocations equate to metric tons (mt) of CO2. RPU can use the majority of these allowances for direct compliance purposes, and monetize the remaining residual allowances in the quarterly Cap and Trade auctions at the prevailing clearing prices. (See section 8.7 for a more detailed discussion on this topic.) For long term budget forecasting purposes, we have assumed that RPU sells its residual Carbon allowances at the corresponding annual Carbon prices shown in Table 10.2.3. Selling our Carbon allowances at these prices produces a positive net cash flow in the IRP budget of 3.0 to 4.0 million dollars annually through 2020.

Beyond 2020, the California Cap and Trade allocation program is not defined, and there is considerable uncertainty surrounding the post-2020 allocation paradigm. Given this uncertainty and the distinct possibility that post-2020 allocations may not be made available to any California LSE's, in our budget forecasts we have assumed that RPU receives no further Carbon allowance allocations beyond 2020. Thus, RPU's post-2020 CO_2 emission costs will need to be absorbed into our budget costs and recovered through our future rates. Under this assumption, the post-2020 Carbon costs therefore directly impact the IRP total budget cost calculation from 2021 through 2033 in each IRP scenario .

Table 10.2.3. RPU's Carbon allowances and budget forecasted Carbon prices through 2020.

Year	Allowances	Carbon Price ($/ton)
2014	1,069,456	$15.00
2015	1,043,302	$15.00
2016	1,066,387	$16.00
2017	1,067,638	$17.00
2018	1,082,987	$18.00
2019	1,079,121	$19.00
2020	1,088,787	$20.00

10.2.4. Current Resource Adequacy Costs

As a CAISO member, RPU is currently required to procure local and system resource adequacy or capacity products equal to a minimum 115% of monthly peak load. The classification of RA as local or system is important because there is a significant difference in their cost; local capacity products currently cost 2.5 times the amount of equivalently sized system capacity products. Currently, RPU obtains RA from a combination of local and system RA resources including its internal generation, PPAs that include RA capacity, and monthly RA bilateral contracts. Going forward, RPU expects to have enough local capacity credit to satisfy its local capacity needs through at least 2025, under the current CAISO paradigm. Thus, in projecting RPU's RA cost for the IRP, we assume that all of RPU's RA procurement shortfalls can be met using system capacity products.

However, it is also very important to note that the CAISO is in midst of redefining the Resource Adequacy paradigm. The first step of CAISO process is the proposed flexible resource adequacy capacity paradigm and the must bid obligation of the flexible capacity. The new requirement is expected to be implemented in CY 2015. Currently, there is a strong indication that RPU will not receive full credit for its generating resources, including RPU's flexible peaking resources because they do not meet the CAISO's newly-created definition of flexible resource adequacy capacity and thus won't qualify to meet the flexible capacity requirement. Thus, RPU may be required to procure additional flexible capacity resources that meet the CAISO flexibility capacity definition to satisfy CAISO's operational needs. The cost of procuring this additional flexible capacity to meet the new requirement is highly uncertain and thus not accounted for in the current IRP.

The RA shortfalls and associated costs that are currently accounted for in the IRP budget cost calculation are a function of the following IRP variables:

- Load growth (Normal or Poor)
- RPS percentage (33% or 40%)
- IPP retirement date (12/31/2020 or 12/31/2025)
- Expected future system RA costs

The effects these variables have on RPU's RA procurement and cost are shown in Table 10.2.4.

Table 10.2.4. IRP variable effects on RA procurement amounts and costs.

Variable	Variable Level	Effect
Load Growth	Strong	Higher
	Weak	Lower
RPS Mandate	33%	Higher
	40%	Lower
IPP Retirement Date	December 31, 2020	Higher, earlier
	December 31, 2025	Higher, later

As shown in Table 10.2.4, RPU will need to procure more RA under a strong load growth scenario, as opposed to the weak load growth scenario. Conversely, because new RPS resources are assumed to provide either local or system RA, RPU will need to procure more RA with the 33% RPS than the 40% RPS. Finally, because IPP contributes significantly to RPU's system RA, RPU will need to procure replacement system RA once this contract terminates. The retirement date simply determines when RPU will begin realizing the replacement RA cost.

Following the assumptions discussed in Chapters 6 (section 6.6) and 9, we assume that our 2014 system RA replacement costs are \$4.00/kW-month in Q3 (July-September), \$1.50/kW-month in May, June and October, and \$0.50/kW-month in November through April, respectively. Additionally, we assume that these costs escalate at 3% annually through 2033.

10.2.5 CAISO Uplift Fees & other Power Resource Costs

In addition to the above mentioned budgetary costs, in 2014 RPU expects to pay $6 million annually for the following all-other, Power Resource related costs:

- CAISO Transmission uplift fees: 1.6 million dollars
- CAISO Energy uplift fees: 0.8 million dollars
- CAISO Congestion Revenue Rights: 1.2 million dollars
- RPU Internal Generation (contingency costs): 2.2 million dollars
- Legislative Mandates (reporting): 0.2 million dollars

In the subsequent IRP analyses, we escalate this 6 million dollar cost at 3% annually in order to produce future cost forecasts of these miscellaneous budgetary expenses. Note that these cost forecasts are common across all twelve IRP scenarios.

10.2.6 Utility Personnel and O&M Costs

In order to fully demonstrate the importance of load growth for RPU's cost of service, we needed a projection of RPU's all other budget costs that are not related to power supply activities and therefore not load dependent. These all-other costs fall into two general categories: (a) general personnel and O&M costs, and (b) debt-service costs. A projection for the first category is presented in the 2014 Electric Financial Plan (dated as of November 18, 2013). This Financial Plan contains specific cost projections through FYE 2017 for the following three categories.

- RPU Personnel Costs
- Other Utility Operating and Maintenance (O&M) costs
- Capital outlay financed by rates

Beyond FYE 2017, we escalate costs in each category by 2% per year through 2033.

10.2.7 Long-term Debt Service Costs

Projecting RPU's debt service requirements from 2014 through 2033 depends on existing and future bond issuances. Estimates of the debt service requirements for RPU's existing bonds are readily available – the specific estimates used in our projection were obtained from the July 10, 2013 Official Statement for Refunding Electric Revenue Bonds, Issue of 2013A and Taxable Electric Revenue Bonds, Issue of 2013B. However, because RPU's future bond issuances are unknown, projecting debt service requirements requires assumptions about new bond issuances, including the timing of issuance, par amount, borrowing rate, maturity of new debt, and debt service structure. For purposes of this IRP, we assume that our future bond issuances are as follows:

- **Timing of Issuance:** Every three years beginning in 2016
- **Par Amount:** $60 million
- **Borrowing Rate**: 5%
- **Maturity**: 30 years

- **Debt Service Structure**: Level

All of these assumptions reflect RPU's historical bond issuances; i.e., a 60 million dollar issuance every three years reflects the typical cost of new capital projects and upgrades to RPU's distribution system.

Upon combining this forecasted debt service structure with the escalated Personnel and O&M costs discussed in sections 10.2.7 and 10.2.6 respectively, the "all-other" annual RPU operating costs shown in Table 10.2.5 were derived. (Details concerning these derivations are presented in Appendix E.) Note that these cost forecasts are treated as common costs across all twelve IRP scenarios and are assumed to be independent of any future Power Resource procurement decisions.

Table 10.2.5. RPU "all-other" operating cost forecasts: 2014 – 2033

Year	Existing Debt Service ($000)	New Debt Service ($000)	Personnel and O&M ($000)	RPU All Other Costs ($000)
2014	$44,630	$0	$58,128	$102,839
2015	$44,955	$0	$58,453	$103,565
2016	$41,680	$3,903	$58,858	$104,424
2017	$41,611	$3,903	$60,027	$105,548
2018	$41,637	$3,903	$61,228	$107,743
2019	$41,635	$7,806	$62,452	$111,894
2020	$41,637	$7,806	$63,701	$113,132
2021	$41,584	$7,806	$64,976	$115,330
2022	$41,538	$11,709	$66,275	$119,507
2023	$41,477	$11,709	$67,601	$120,772
2024	$41,415	$11,709	$68,953	$123,037
2025	$41,354	$15,612	$70,332	$127,275
2026	$41,262	$15,612	$71,738	$128,598
2027	$41,203	$15,612	$73,173	$130,943
2028	$41,119	$19,515	$74,636	$135,250
2029	$41,035	$19,515	$76,129	$136,658
2030	$40,946	$19,515	$77,652	$139,066
2031	$40,856	$23,419	$79,205	$143,453
2032	$40,752	$23,419	$80,789	$144,934
2033	$40,648	$23,419	$82,405	$147,420

10.2.8 General Fund Transfer (GFT)

An additional cost category that directly impacts RPU's cost of service is the annual General Fund Transfer (GFT) fee. The GFT has been approved by Riverside's residents on at least three separate occasions and is defined in Section 1204(f) of the City's Charter as an amount not to exceed 11.5 percent of gross operating revenues, exclusive of surcharges, for the last fiscal year. This expenditure is used to support general City services to the community such as police, fire, parks, museums, libraries, etc., that improve the quality of life in Riverside. Currently the GFT is calculated as 11.5% of RPU's gross customer sales and transmission revenues, thus a technically correct forecast of the GFT should be based upon a forecast of future RPU revenues. However, because we are attempting to specifically avoid forecasting revenues in this IRP analysis, we have taken an alternative approach to estimating future GFT levels. More specifically, we first calculate our total net cost of service (NCOS) before the GFT as the TNPC plus the sum of all of the additional portfolio costs discussed in sections 10.2.1 through 10.2.7, minus any revenue from the sale of carbon allowances. Mathematically, this formula can be expressed as

$$\text{NCOS} = \text{TNPC} + \text{SONGS} + \text{TAC} + \text{RA} + \text{UFOC} + \text{AO} - \text{GHG}$$

where the remaining variables represent our additional costs associated with SONGS, our CAISO Transmission Access charge (TAC), system RA needs (RA), CAISO uplift fees and other Power Resource costs (UFOC), our all-other (AO) utility costs, including our long-term debt service requirements, and our GHG allowance revenues (GHG), if any. Once the net COS has been determined, we then divide this by the additional GFT ratio to produce a gross cost of service (GCOS) estimate; i.e.,

$$\text{GCOS} = \text{NCOS} / 0.885$$

where the 0.885 division factor is used to calculate the additional revenue that must be obtained in order for our total revenues to be in balance with our total gross COS.

10.2.9 Load Normalized Cost of Service (COS_{LN}) Metrics

As defined above, our GCOS estimates represent our all-in RPU cost of service forecasts for the various IRP scenarios discussed in this chapter. To a significant degree, these GCOS estimates increase as our load metric increases. Hence, for planning purposes it is more useful to examine a "load normalized" GCOS metric, since this essentially corresponds to the future average retail rate that RPU must charge to fully recover all of its expected costs. In the following IRP analyses, this load normalized metric (COS_{LN}) is defined as

$$COS_{LN} = \text{GCOS} / \text{Retail.Load}$$

where by definition our retail load is set equal to 95% of our total (strong or weak) system load forecasts, respectively.

This being said, it is important to recognize that these COS_{LN} estimates are primarily designed to facilitate an effective comparison between the different IRP scenarios, rather than to forecast our absolute expected rate requirements twenty years into the future. Additionally, it should also be noted that the calculated standard deviations for these COS_{LN} estimates only quantify the uncertainty associated with the TNPC, TAC, GHG and RA variables. The remaining variables incorporated into the NCOS estimate are treated as fixed variables (i.e., devoid of any uncertainty).

In the remainder of this chapter we will examine how the forecasted cost of service metrics change across our different IRP scenarios. Our primary goal will be to quantify both the absolute and relative cost of service and risk differences between these scenarios, in order to determine the degree to which each primary input variable influences these metrics.

10.3 Load Growth Rate and RPS Mandate Impacts on RPU's COS_{LN}

Figure 10.3.1 shows our projected annual COS_{LN} estimates (shown in ₵/kWh units) for the four IRP scenarios that define our two load growth and RPS mandate assumptions; i.e., strong versus weak load growth and a 33% versus 40% RPS mandate. Note that our IPP contract is assumed to run through 2025 in each of these four scenarios, and unhedged, SP15 market power is used to fill the energy void upon contract termination. Additionally, Table 10.3.1 shows the corresponding COS_{LN} estimates for years 2018, 2023, 2028 and 2033, respectively, and summarizes some relevant scenario comparisons. More specifically, the annual COS_{LN} growth rate for each scenario is shown in the last column, and the bottom four rows quantify pertinent % cost increases across specific scenarios (that correspond to changes across specific IRP input variables).

As shown in Figure 10.3.1., our assumed future load growth rate predominantly determines our future cost-of-service forecasts in these scenario comparisons. The effect of the RPS mandate (33% versus 40%) is far less pronounced, and even difficult to clearly distinguish under a weak load growth assumption. The % cost increase comparisons shown for "Scenario B vs A" and "Scenario D vs C" quantify the impacts on our expected cost of service if we were to adopt a 40% RPS mandate under current renewable energy pricing expectations – this cost increase is forecasted to be less than 1%. In contrast, we can expect our cost of service to be about 10% higher by 2028 (and 13% higher by 2033) under a weak load growth scenario, as compared to the strong (healthy) growth scenario (see "Scenario C vs A" and "D vs B", respectively). Likewise, note that the annual COS_{LN} growth rate is 1.5% under the weak load growth scenario, versus just 1.0% under the strong growth scenario.

The other important features shown in Figure 10.3.1 are the abrupt cost increases that occur in 2021 and 2026. The 0.6 ₵/kWh to 0.7 ₵/kWh cost of service increase in 2026 is due to the termination of our IPP contract (on January 1, 2026). In contrast, the 1.0 ₵/kWh to 1.1 ₵/kWh cost increase in 2021 is a direct result of the end of free Carbon allowances; i.e., this is the cost increase that RPU should expect to absorb if no further emission compliance instruments are freely allocated after 2020.

Figure 10.3.2 shows the projected annual COS_{LN} uncertainty estimates ($Std[COS_{LN}]$), again shown in ₵/kWh units) for the four corresponding scenarios shown in Figure 10.3.1. Note that under all four scenarios, our portfolio risk more than doubles by 2026. This effect is primarily a result of two events: (1) the significant uncertainty about the cost of Carbon allowances on/after 2021, and (2) the replacement of our IPP contract (which essentially represents a fixed price generation asset) with open, unhedged SP15 market energy purchases. With respect to the relative portfolio risk, values at or below 4% represent a well hedged portfolio that can effectively withstand significant market price swings. Higher values indicate more potential cash flow uncertainty and corresponding portfolio risk. Table 10.3.2 shows that our portfolio risk increases to above 1 ₵/kWh under all of these scenarios (7% - 8%

relative risk), which is much higher than our current risk level (~ 3%). Note that the relationships between our cost of service, the relative risk level and potential price shocks are explored in more detail in section 10.6.

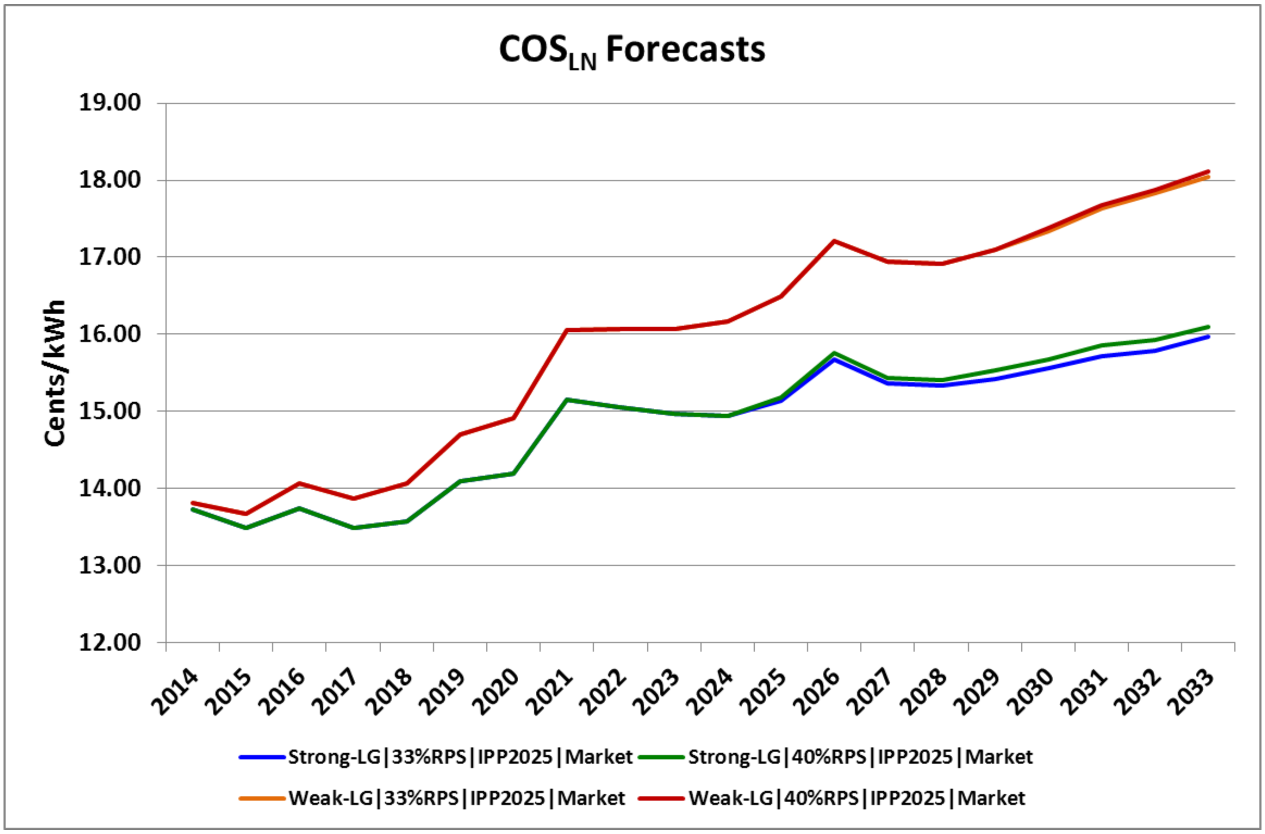


Figure 10.3.1. Projected annual COS$_{LN}$ estimates for two load growth assumptions and RPS mandates: (strong versus weak load growth & 33% versus 40% RPS mandates), assuming a 2025 IPP contract termination date.

Table 10.3.1. Figure 10.3.1 COS$_{LN}$ estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (annual growth rates and relative cost increases). All cost units shown in ₵/kWh.

Scenario	**2018**	**2023**	**2028**	**2033**	**Annual GR%**
A. Strong-LG|33%RPS|IPP2025|Market	13.572	14.961	15.336	15.962	1.0%
B. Strong-LG|40%RPS|IPP2025|Market	13.572	14.961	15.411	16.100	1.0%
C. Weak-LG|33%RPS|IPP2025|Market	14.060	16.068	16.918	18.047	1.5%
D. Weak-LG|40%RPS|IPP2025|Market	14.060	16.068	16.918	18.107	1.5%
Scenario B vs A	0.0%	0.0%	0.5%	0.9%	
Scenario D vs C	0.0%	0.0%	0.0%	0.3%	
Scenario C vs A	3.6%	7.4%	10.3%	13.1%	
Scenario D vs B	3.6%	7.4%	9.8%	12.5%	

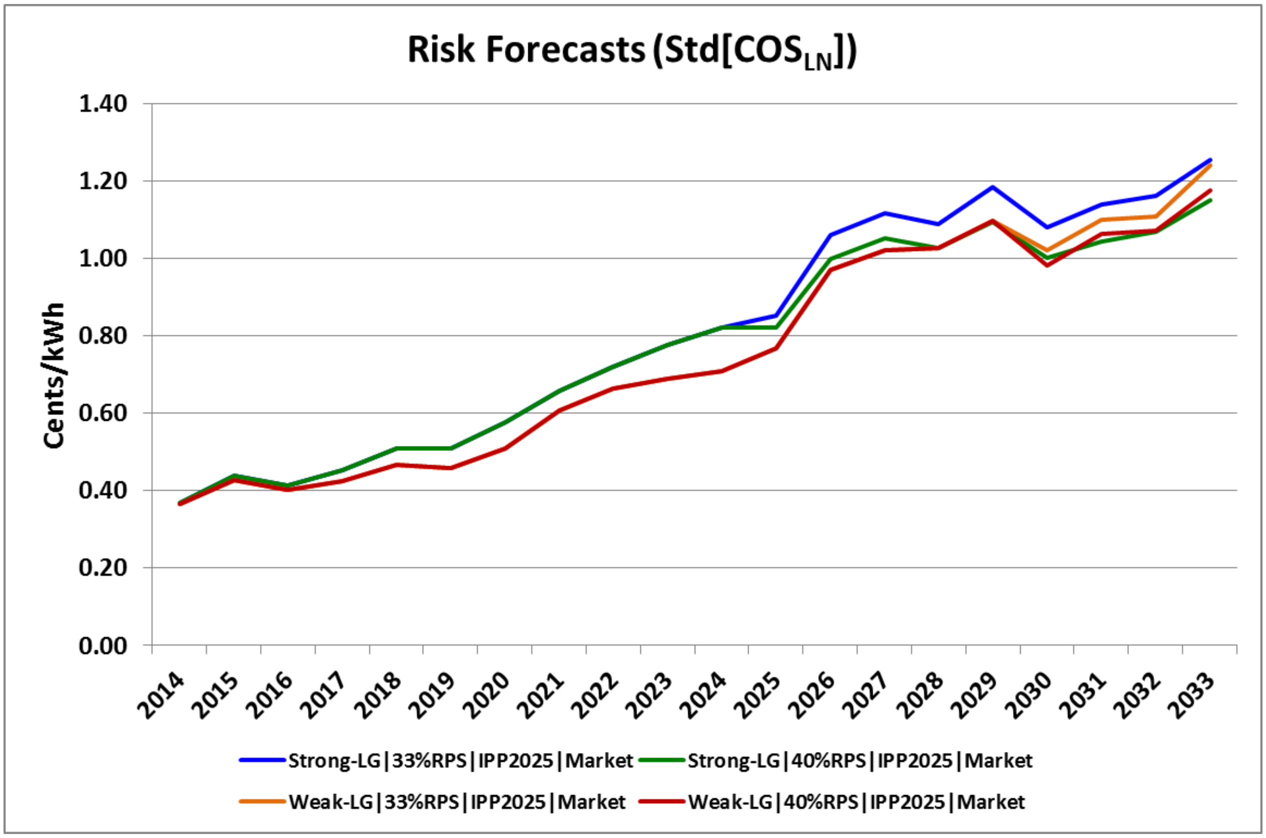


Figure 10.3.2. Corresponding annual COS_{LN} risk estimates (Std[COS_{LN}]) for two load growth assumptions and RPS mandates: (strong versus weak load growth & 33% versus 40% RPS mandates), assuming a 2025 IPP contract termination date.

Table 10.3.2. Figure 10.3.2 COS_{LN} risk estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (relative risk levels). All cost units shown in ₵/kWh.

Scenario	2018	2023	2028	2033
A. Strong-LG|33%RPS|IPP2025|Market	0.507	0.777	1.088	1.255
B. Strong-LG|40%RPS|IPP2025|Market	0.507	0.777	1.026	1.151
C. Weak-LG|33%RPS|IPP2025|Market	0.466	0.688	1.027	1.239
D. Weak-LG|40%RPS|IPP2025|Market	0.466	0.688	1.027	1.176
Relative Risk of Scenario A	3.7%	5.2%	7.1%	7.9%
Relative Risk of Scenario B	3.7%	5.2%	6.7%	7.2%
Relative Risk of Scenario C	3.3%	4.3%	6.1%	6.9%
Relative Risk of Scenario D	3.3%	4.3%	6.1%	6.5%

Figure 10.3.3 shows our projected annual COS_{LN} estimates (shown in ₵/kWh units) for four additional IRP scenarios that define our two load growth and RPS mandate assumptions, but where our IPP contract is now instead assumed to terminate after 2020 in each scenario. As before, unhedged SP15 market power is used to fill the energy void upon contract termination. Additionally, Table 10.3.3 shows the corresponding COS_{LN} estimates for years 2018, 2023, 2028 and 2033, respectively, and again summarizes some relevant scenario comparisons. (The annual COS_{LN} growth rate for each scenario is shown in the last column, and the bottom four rows quantify pertinent % cost increases for specific scenario comparisons.)

Our assumed future load growth rate again predominantly determines our future cost-of-service forecasts. The effect of the RPS mandate (33% versus 40%) is again almost difficult to clearly distinguish under a weak load growth assumption in Figure 10.3.3. As shown in Table 10.3.3, the % cost increase comparisons for "Scenario B vs A" and "Scenario D vs C" quantify the impacts on our expected cost of service if we again adopt a 40% RPS mandate under current renewable energy pricing expectations – this cost increase is again forecasted to be less than 1%. In contrast, we can still expect our cost of service to be about 10% higher by 2028 (and 13% higher by 2033) under a weak load growth scenario, as compared to the strong (healthy) growth scenario (see "Scenario C vs A" and "D vs B", respectively). As before, note that the annual COS_{LN} growth rate is 1.5% under the weak load growth scenario, versus just 1.0% under the strong growth scenario.

The main differences shown in Figure 10.3.3 are the sudden cost of service increases that now occur entirely in 2021. Under the strong load growth assumption, our COS_{LN} increases from 14.193 ₵/kWh to 15.702 ₵/kWh (2020 versus 2021). Likewise, under the weak load growth assumption, our COS_{LN} increases from 14.911 ₵/kWh to 16.669 ₵/kWh. This 1.6 ₵/kWh to 1.7 ₵/kWh cost increase represents the combined effects of an early IPP contract termination event <u>and</u> the end of our free Carbon allowances after 2020.

Figure 10.3.4 shows the projected annual COS_{LN} uncertainty estimates (Std[COS_{LN}]) for the four corresponding scenarios shown in Figure 10.3.3. In these four scenarios, our portfolio risk more than doubles on/after 2021. Once again, this effect is a direct result of the replacement of our IPP contract with open, unhedged SP15 market energy purchases, combined with the significant uncertainty surrounding future Carbon allowance costs. The data in Table 10.3.4 confirms that our portfolio risk again increases to above 1 ₵/kWh under all four scenarios (7% - 8% relative risk by 2033).

One other trend worth noting in Figures 10.3.2 and 10.3.4 is that the uncertainty estimates for the 40% RPS scenarios are slightly lower than the corresponding 33% RPS mandate estimates (once the additional renewable generation assets are added to the portfolio). This slight risk reduction effect reflects the fixed price certainty of the renewable assets. This represents one of the added benefits of renewable generation assets that are procured under fixed-price PPA's; i.e., these contracts can help reduce our cash flow uncertainty, provided that their associated energy production effectively hedges our expected future load serving needs.

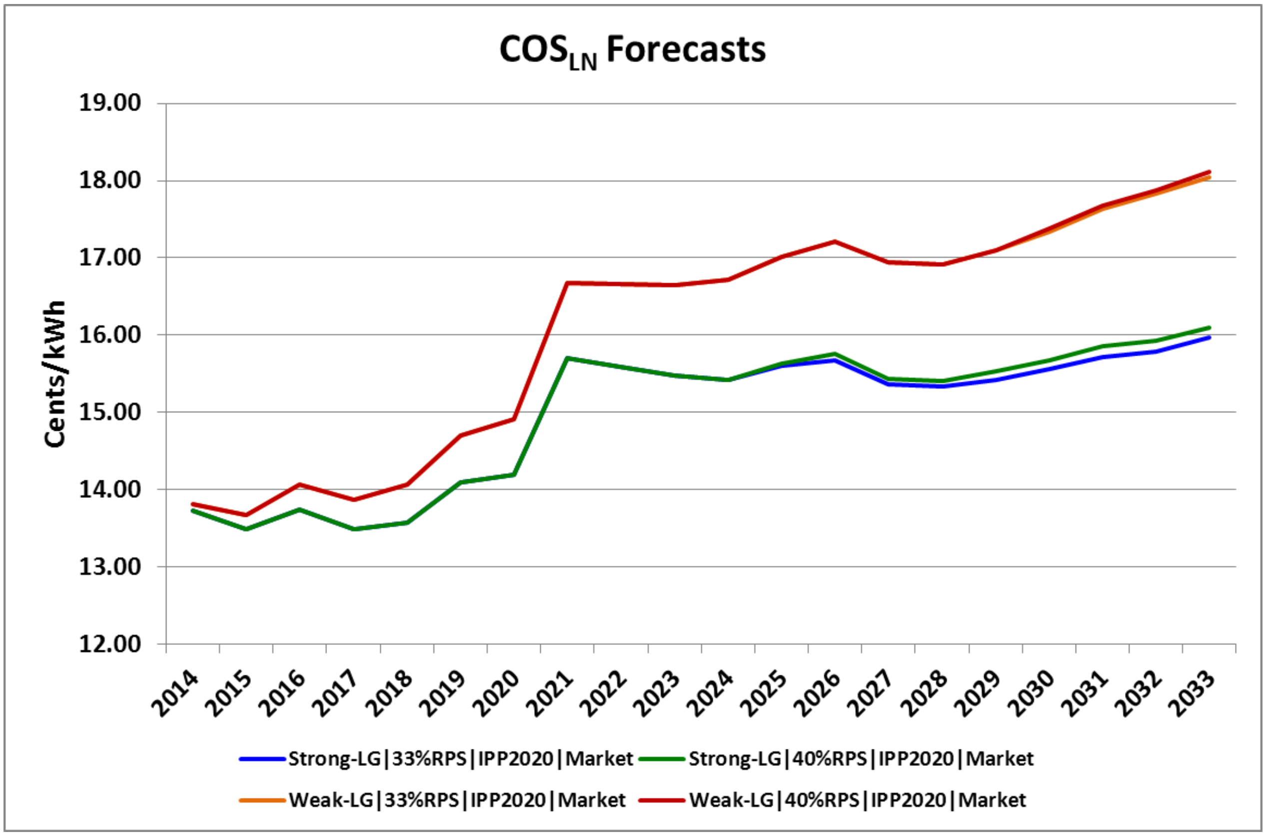


Figure 10.3.3. Projected annual COS_{LN} estimates for two load growth assumptions and RPS mandates: (strong versus weak load growth & 33% versus 40% RPS mandates), assuming a 2020 IPP contract termination date.

Table 10.3.3. Figure 10.3.3 COS_{LN} estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (annual growth rates and relative cost increases). All cost units shown in ₵/kWh.

Scenario	2018	2023	2028	2033	AGR%
A. Strong-LG|33%RPS|IPP2020|Market	13.571	15.472	15.336	15.962	1.0%
B. Strong-LG|40%RPS|IPP2020|Market	13.571	15.472	15.411	16.100	1.0%
C. Weak-LG|33%RPS|IPP2020|Market	14.059	16.642	16.918	18.047	1.5%
D. Weak-LG|40%RPS|IPP2020|Market	14.059	16.642	16.918	18.107	1.5%
Scenario B vs A	0.0%	0.0%	0.5%	0.9%	
Scenario D vs C	0.0%	0.0%	0.0%	0.3%	
Scenario C vs A	3.6%	7.6%	10.3%	13.1%	
Scenario D vs B	3.6%	7.6%	9.8%	12.5%	

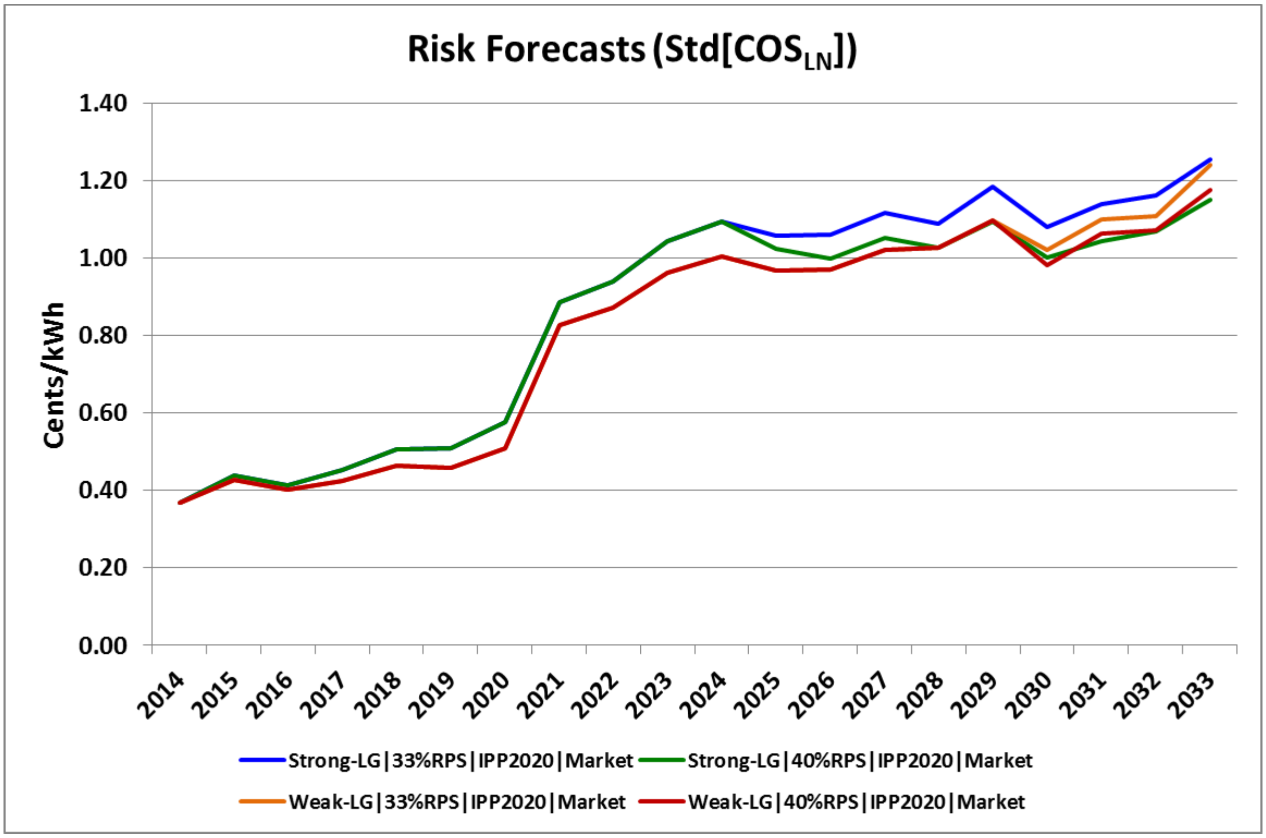


Figure 10.3.4. Corresponding annual COS_{LN} risk estimates (Std[COS_{LN}]) for two load growth assumptions and RPS mandates: (strong versus weak load growth & 33% versus 40% RPS mandates), assuming a 2020 IPP contract termination date.

Table 10.3.4. Figure 10.3.4 COS_{LN} risk estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (relative risk levels). All cost units shown in ₵/kWh.

Scenario	2018	2023	2028	2033
A. Strong-LG|33%RPS|IPP2020|Market	0.506	1.042	1.088	1.255
B. Strong-LG|40%RPS|IPP2020|Market	0.506	1.042	1.026	1.151
C. Weak-LG|33%RPS|IPP2020|Market	0.464	0.963	1.027	1.239
D. Weak-LG|40%RPS|IPP2020|Market	0.464	0.963	1.027	1.176
Relative Risk of Scenario A	3.7%	6.7%	7.1%	7.9%
Relative Risk of Scenario B	3.7%	6.7%	6.7%	7.2%
Relative Risk of Scenario C	3.3%	5.8%	6.1%	6.9%
Relative Risk of Scenario D	3.3%	5.8%	6.1%	6.5%

10.4 IPP Contract Termination: Timing Impact on COS_{LN}

The previous analysis in section 10.3 clearly suggests that the timing of our IPP contract termination date will significantly impact our future COS_{LN} estimates. Figure 10.4.1 shows our projected annual COS_{LN} estimates for the four IRP scenarios that define our two load growth and IPP contract end-date assumptions (December 31, 2020 and 2025), under a 33% RPS mandate. Note that our IPP contract is assumed to be replaced with unhedged, SP15 market power upon contract termination in all four scenarios. Additionally, Table 10.4.1 shows the corresponding COS_{LN} estimates for years 2018, 2023, 2028 and 2033, respectively, and again summarizes some relevant scenario comparisons.

Once again, our assumed future load growth rate predominantly determines our future cost-of-service forecasts in these scenario comparisons. However, the IPP contract termination date also plays an important role in determining the COS_{LN} values between 2020 and 2026. The % cost increase comparisons shown in Table 10.4.1 for "Scenario B vs A" and "Scenario D vs C" quantify the impacts on our expected cost of service if we were to pursue an early IPP retirement data under current energy pricing expectations – this cost increase is forecasted to be about 3.5%. As before, we can expect our cost of service to be about 10% higher by 2028 (and 13% higher by 2033) under a weak load growth scenario, as compared to the strong (healthy) growth scenario (see "Scenario C vs A" and "D vs B", respectively).

The other important feature shown in Figure 10.4.1 is that we can expect our cost of service to remain relatively flat for about 8-10 years after an early IPP contract end-date, at least under the strong load growth assumption. While it is impossible to know or forecast all of the new cost pressures that could impact RPU ten to fifteen years into the future, these results do suggest that the IPP contract termination date and future Carbon emission paradigm clearly represent the dominant forces currently impacting our future COS_{LN} forecasts. Hence, if RPU can successfully resolve these two issues in a cost effective manner, we should be able to better minimize the need for significant future rate increases.

Figure 10.4.2 shows the projected annual COS_{LN} uncertainty estimates (Std[COS_{LN}]) for the four corresponding scenarios shown in Figure 10.4.1. As quantified in Table 10.4.2, under all four scenarios our portfolio risk exceeds 1.0 ₵/kWh by 2028 (6% to 7% relative risk). Again, this is a direct result of the replacement of our IPP contract with open, unhedged SP15 market energy purchases, combined with the significant uncertainty surrounding future Carbon allowance costs. Additionally, note that the timing of the IPP contract end-date strongly influences this risk metric.

Given that RPU strives to minimize its portfolio risk whenever possible, it is highly unlikely that we would voluntarily elect to leave such a large open position unhedged in our portfolio. A much more likely scenario is that our IPP contract will be replaced with some type of generation asset (or fixed price contract), or hedged market purchases, in order to mitigate our future portfolio risk. In the next section we begin to specifically examine this issue in more detail, by analyzing how our forecasted portfolio risk will be impacted if we replace or IPP contract with 150 MW of forward hedged energy contracts.

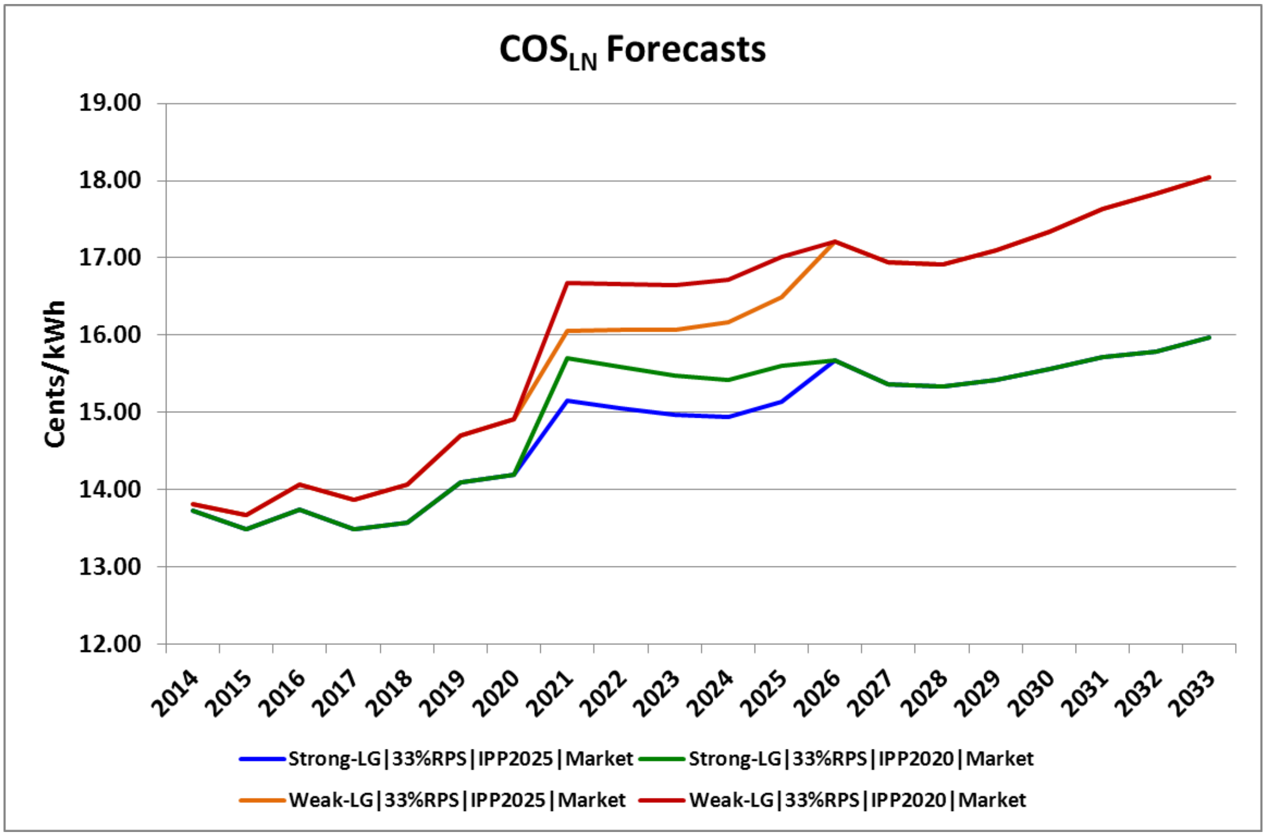


Figure 10.4.1. Projected annual COS_{LN} estimates for two load growth assumptions and IPP contract end-dates: (strong versus weak load growth & December 31, 2020 versus December 31, 2025), assuming a 33% RPS mandate.

Table 10.4.1. Figure 10.4.1 COS_{LN} estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (annual growth rates and relative cost increases). All cost units shown in ₵/kWh.

Scenario	2018	2023	2028	2033	AGR%
A. Strong-LG|33%RPS|IPP2025|Market	13.572	14.961	15.336	15.962	1.0%
B. Strong-LG|33%RPS|IPP2020|Market	13.571	15.472	15.336	15.962	1.0%
C. Weak-LG|33%RPS|IPP2025|Market	14.060	16.068	16.918	18.047	1.5%
D. Weak-LG|33%RPS|IPP2020|Market	14.059	16.642	16.918	18.047	1.5%
Scenario B vs A	0.0%	3.4%	0.0%	0.0%	
Scenario D vs C	0.0%	3.6%	0.0%	0.0%	
Scenario C vs A	3.6%	7.4%	10.3%	13.1%	
Scenario D vs B	3.6%	7.6%	10.3%	13.1%	

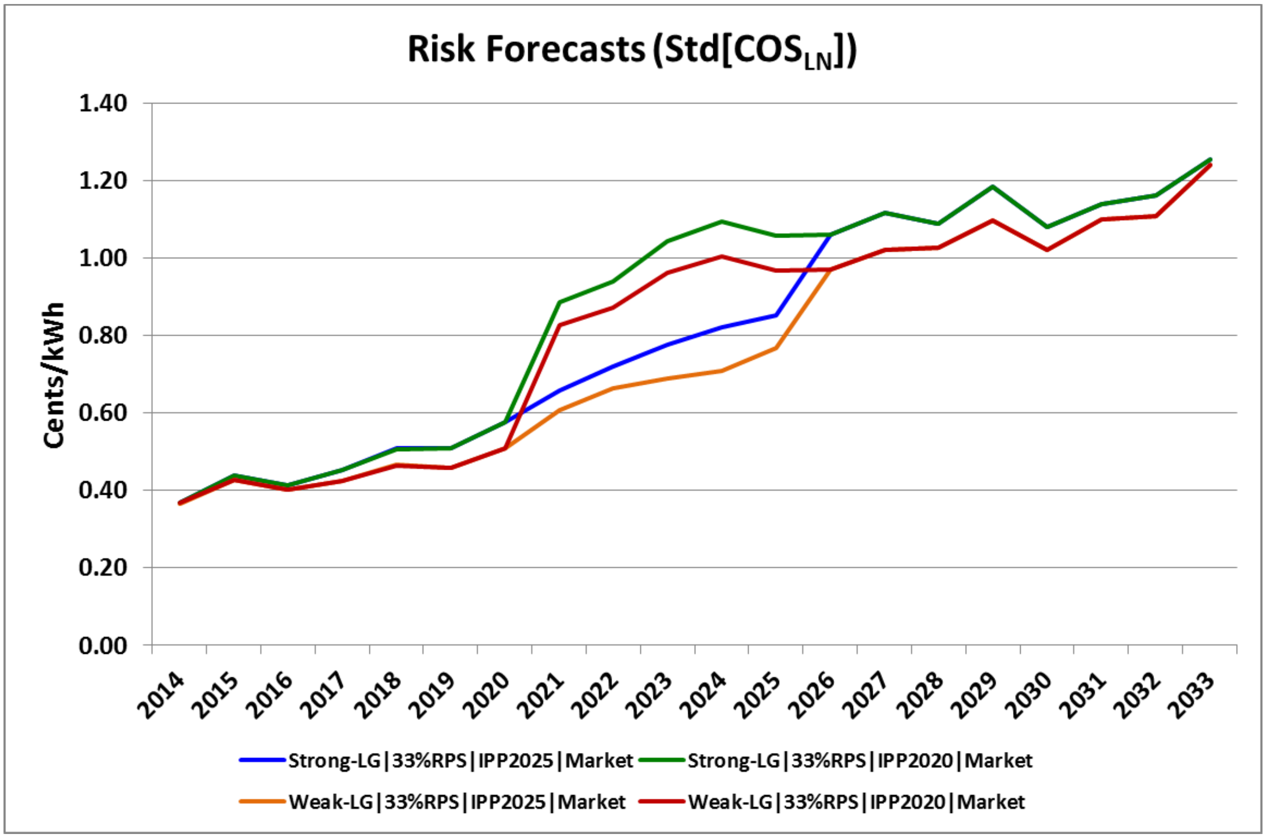


Figure 10.4.2. Corresponding annual COS_{LN} risk estimates (Std[COS_{LN}]) for two load growth assumptions and IPP contract end-dates: (strong versus weak load growth & December 31, 2020 versus December 31, 2025), assuming a 33% RPS mandate.

Table 10.4.2. Figure 10.4.2 COS_{LN} risk estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (relative risk levels). All cost units shown in ₵/kWh.

Scenario	2018	2023	2028	2033
A. Strong-LG|33%RPS|IPP2025|Market	0.507	0.777	1.088	1.255
B. Strong-LG|33%RPS|IPP2020|Market	0.506	1.042	1.088	1.255
C. Weak-LG|33%RPS|IPP2025|Market	0.466	0.688	1.027	1.239
D. Weak-LG|33%RPS|IPP2020|Market	0.464	0.963	1.027	1.239
Relative Risk of Scenario A	3.7%	5.2%	7.1%	7.9%
Relative Risk of Scenario B	3.7%	6.7%	7.1%	7.9%
Relative Risk of Scenario C	3.3%	4.3%	6.1%	6.9%
Relative Risk of Scenario D	3.3%	5.8%	6.1%	6.9%

10.5 IPP Replacement Option Impacts on COS_{LN}

As discussed in section 10.4, RPU will need to replace our IPP resource with some other form of hedged energy product when our IPP contract terminates, if we wish to minimize our future budgetary cash flow uncertainty. A number of viable generation alternatives will be examined in detail in Chapter 11. However, to simplify these studies we have examined just one alternative replacement scenario, specifically hedged market purchases. In practice, Riverside would begin acquiring these forward energy products in stages over a multi-year time-frame, five to six years before our IPP contract was to terminate. (This type of "layered" hedging strategy reduces the uncertainty around the average forward energy price, as discussed in greater detail below.) While this is certainly not our only power replacement alternative, it does represent a realistic option that is beneficial to individually analyze, at least with respect to how it could impact on our future portfolio risk metrics.

In the following analysis we assume that RPU begins purchasing 6-year strips of 25 MW annual base-load energy products five years before our IPP contract terminates. Under this layered hedging approach, one strip is purchased in each preceding year (and the final strip at the target year), so that by the contract termination date RPU will have acquired 150 MW of hedged energy products. By averaging the purchase costs over this extended time period, we will acquire an average forward price more closely aligned with our current forward market forecasts. Based on current market conditions, we estimate the volatility (i.e., standard deviation) around this five year layered hedging approach to be 4% of current market price forecasts. Hence, in the subsequent analyses, we assume for simplicity that one standard deviation of price uncertainty represents our "implied hedging cost", and thus incorporate a constant 4% cost adder to our hedged market purchases.

Finally, note that these forward energy hedges do not include any bundled RA capacity. As with all other scenarios containing open market positions, our RA capacity needs and associated costs are calculated separately.

Given all of the assumptions discussed above, Figure 10.5.1 shows our projected annual COS_{LN} estimates for both hedged and unhedged energy replacement options under our two load growth scenarios, assuming an IPP contract termination date of December 31, 2020. Note that since there is only a 4% energy cost difference between our hedged and unhedged energy replacement options, there is relatively little cost difference (on average) between the hedged and unhedged scenarios (i.e., < 1% throughout the analyzed time horizon). Table 10.5.1 shows the corresponding COS_{LN} estimates for years 2018, 2023, 2028 and 2033, respectively, and verifies the near cost equivalence between the "Market" and "Market-Hedged" scenarios. In contrast (and as expected), there are the previously discussed large cost differences between the two sets of load growth scenarios.

The fundamental differences between these four scenarios reveal themselves in Figure 10.5.2 and Table 10.5.2, respectively. Figure 10.5.2 shows the projected annual COS_{LN} uncertainty estimates ($Std[COS_{LN}]$) for the four hedged and unhedged energy replacement scenarios shown in Figure 10.5.1. As shown in this figure and quantified in Table 10.5.2, these four scenarios produce very different forward uncertainty estimates. More specifically, the pronounced risk reduction benefit obtained by forward hedging our replacement energy needs is clearly evident. For example, forward energy hedges reduce our 2023 COS_{LN} uncertainty estimates nearly 65% under the strong load growth assumption (from 1.042 ₵/kWh down to 0.406 ₵/kWh). Additionally, the relative risk under this scenario is held at or below 4.1% throughout the simulated time horizon (and below 3% under the weak load growth assumption). The obvious conclusion from this analysis is that if we intend to replace our lost IPP energy with CAISO Market purchases, then a long-term forward energy hedging strategy must be employed if we wish to minimize our future budgetary risk. Additionally, this result holds regardless of the underlying load growth assumptions. (For the record, this result also holds regardless of the assumed RPS % or specific IPP contract termination date.)

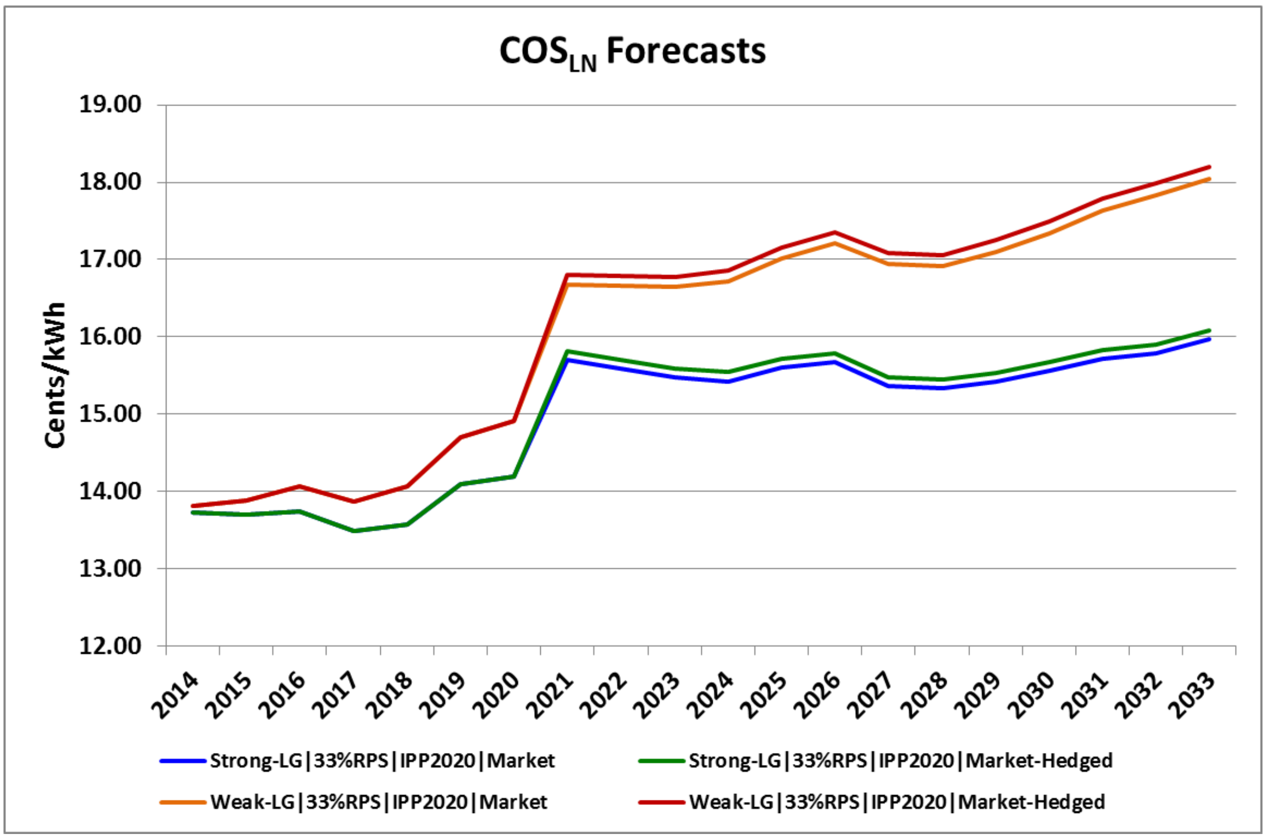


Figure 10.5.1. Projected annual COS_{LN} estimates for hedged and unhedged energy replacement options under two (strong and weak) load growth scenarios, assuming a 33% RPS mandate and a 2020 IPP contract termination date.

Table 10.5.1. Figure 10.5.1 COS_{LN} estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (annual growth rates and relative cost increases). All cost units shown in ₵/kWh.

Scenario	2018	2023	2028	2033	AGR%
A. Strong-LG|33%RPS|IPP2020|Market	13.571	15.472	15.336	15.962	1.0%
B. Strong-LG|33%RPS|IPP2020|Market-Hedged	13.571	15.588	15.451	16.079	1.0%
C. Weak-LG|33%RPS|IPP2020|Market	14.059	16.642	16.918	18.047	1.5%
D. Weak-LG|33%RPS|IPP2020|Market-Hedged	14.059	16.775	17.062	18.204	1.5%
Scenario B vs A	0.0%	0.7%	0.8%	0.7%	
Scenario D vs C	0.0%	0.8%	0.8%	0.9%	
Scenario C vs A	3.6%	7.6%	10.3%	13.1%	
Scenario D vs B	3.6%	7.6%	10.4%	13.2%	

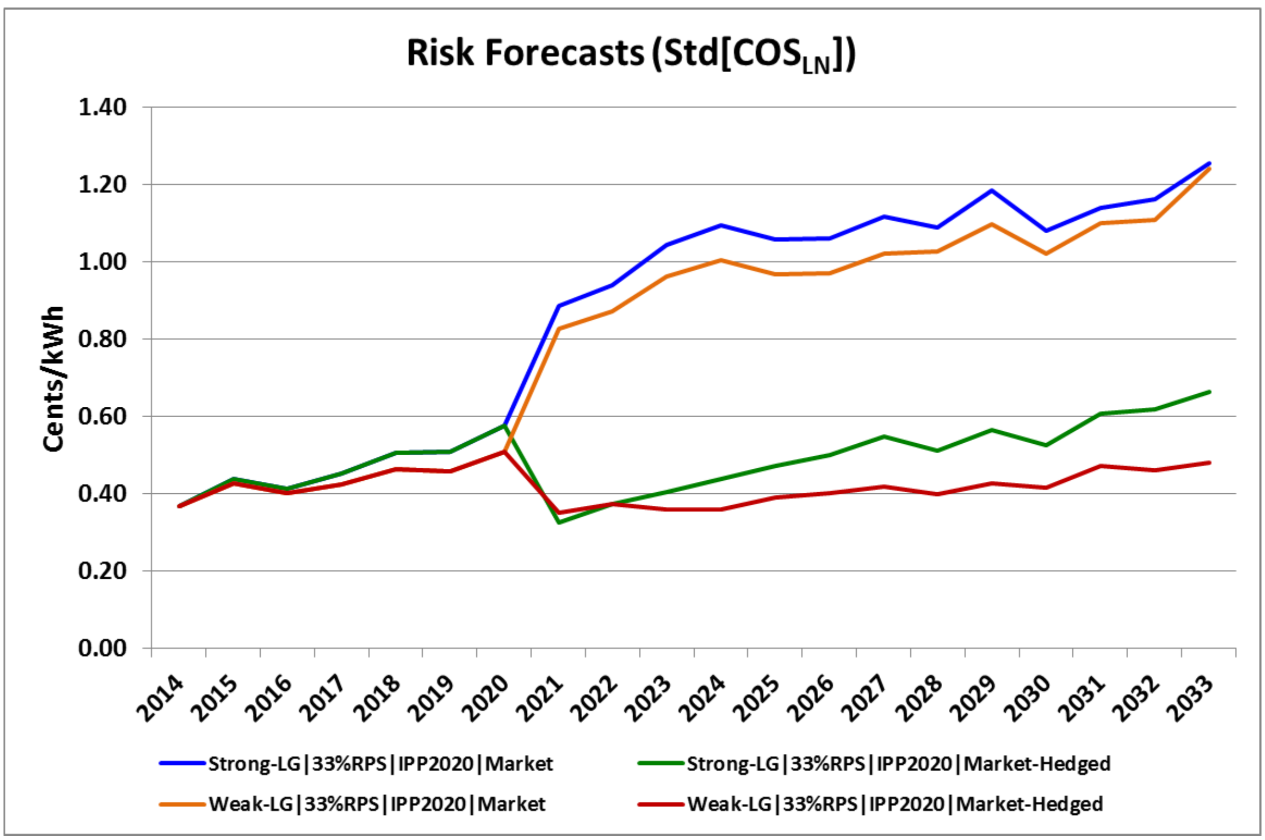


Figure 10.5.2. Corresponding annual COS_{LN} risk estimates (Std[COS_{LN}]) for the hedging and load growth scenarios shown in Figure 10.5.1, under a 33% RPS mandate and a 2020 IPP contract termination date.

Table 10.5.2. Figure 10.5.2 COS_{LN} risk estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (relative risk levels). All cost units shown in ₵/kWh.

Scenario	2018	2023	2028	2033
A. Strong-LG|33%RPS|IPP2020|Market	0.506	1.042	1.088	1.255
B. Strong-LG|33%RPS|IPP2020|Market-Hedged	0.506	0.406	0.513	0.664
C. Weak-LG|33%RPS|IPP2020|Market	0.464	0.963	1.027	1.239
D. Weak-LG|33%RPS|IPP2020|Market-Hedged	0.464	0.358	0.398	0.480
Relative Risk of Scenario A	3.7%	6.7%	7.1%	7.9%
Relative Risk of Scenario B	3.7%	2.6%	3.3%	4.1%
Relative Risk of Scenario C	3.3%	5.8%	6.1%	6.9%
Relative Risk of Scenario D	3.3%	2.1%	2.3%	2.6%

10.6 Market Price Shocks: Impacts on COS_{LN}

In the previous three sections we have examined how our load growth rate assumption, RPS mandate assumption, IPP termination date and unhedged versus hedged energy replacement options impact our COS_{LN} metric and associated portfolio risk. These results suggest that while a 40% RPS mandate can be achieved at minimal additional cost, our load growth rate will significantly impact our long term cost of service, and our (energy replacement) hedging strategy will predominantly determine our future risk profile. Additionally, the loss of free Carbon emission allocations after 2020 is also projected to significantly impact our costs, in addition to the timing of our IPP contract termination date.

In this section we examine a related issue that is very important to consider in any long term planning exercise: market price shocks. More specifically, we wish to address the following basic question: how much will our cost of service increase if the long term market energy prices (i.e., power and natural gas prices) were to systematically increase by 10%, 25% or 50%? Likewise, how would our risk profile change under these same set of price shocks? We attempt to answer these questions by analyzing one of the baseline IRP scenarios (strong load growth, 33% RPS, 2020 IPP contract termination date) under our two energy replacement options; i.e., under the assumptions of unhedged market purchases versus forward hedged energy contracts.

Figure 10.6.1 shows our projected annual COS_{LN} estimates for the baseline IRP scenario using unhedged market purchases as an IPP replacement option, along with this same scenario run under the three market price shocks discussed above. Recall again that the IPP replacement market purchases are assumed to start on January 1, 2021; the corresponding effect on our projected cost of service is clearly evident in Figure 10.6.1, especially under the 25% and 50% price shock scenarios. The corresponding COS_{LN} estimates shown in Table 10.6.1 are likewise very informative, particularly when we compare years 2018 versus 2028. In 2018 we find that our COS_{LN} is nearly immune to these hypothetical market price shocks; indeed, a 50% increase in market pricing results in only a 3.8% increase in our forecasted cost of service. This resilience is a direct result of an effectively hedged portfolio; RPU is currently well positioned to withstand sudden, significant market price increases because we have secured sufficient long-term, fixed price resources to meet our load serving needs. However, in 2028 (after our IPP contract has retired under any expected future scenario), this same 50% market price shock would be expected to raise our cost of service by almost 14%. In direct contrast to the 2018 result, we now have a material open load serving position exposed to the SP15 market, and thus become much more vulnerable to significant price movements in the forward energy markets.

These results are further substantiated by the portfolio risk metrics shown in Figure 10.6.2 and Table 10.6.2. Figure 10.6.2 shows the projected annual COS_{LN} uncertainty estimates for the four scenarios shown in Figure 10.6.1. Table 10.6.2 shows the corresponding forward uncertainty estimates for years 2018, 2023, 2028 and 2033, respectively. Again, before 2020 our portfolio risk estimates hardly change under the different forward price shock scenarios; even under the 50% price shock our 2018 risk metric is projected to remain below 4%. After 2020 however, all of our risk metrics increase significantly; by 2028 we are facing 7% to 10% relative risk under these four scenarios. Again, this is a direct result of having a material open load serving position exposed to the SP15 market.

Figure 10.6.3 shows our projected annual COS_{LN} estimates for the second baseline IRP scenario, again subject to the 10%, 25% and 50% market price shocks. This scenario instead assumes that 150 MW of forward hedged energy contracts are used to replace our lost IPP energy, beginning on January 1, 2021. As before, the corresponding effect on our projected cost of service at/beyond 2021 is clearly evident in Figure 10.6.3, but now there is not nearly the same degree of cost differentiation between the various scenarios. The corresponding COS_{LN} estimates shown in Table 10.6.3 are now very different. In contrast to the previous results shown in Table 10.6.1, we find that our COS_{LN} remains nearly immune to these hypothetical market price shocks throughout the simulated time horizon. The forward purchased energy contracts effectively hedge our portfolio; i.e., we no longer have a material open load serving position exposed to the SP15 market, and thus are no longer nearly so vulnerable to significant price movements in the forward energy or natural gas markets.

As before, these results are further substantiated by the portfolio risk metrics shown in Figure 10.6.4 and Table 10.6.4. Figure 10.6.4 shows the revised annual COS_{LN} uncertainty estimates for the four scenarios shown in Figure 10.6.3. Table 10.6.4 shows the corresponding forward uncertainty estimates for years 2018, 2023, 2028 and 2033, respectively. In contract to Figure 10.6.2 and Table 10.6.2, these new portfolio risk forecasts stay near or below 4% on a relative basis at least through 2028, even for the 50% market price shock scenario. These results confirm that the forward energy contracts can be used to effectively hedge our RPU portfolio, and thus certainly represent one viable replacement option for our IPP contract.

As stated above, the primary purpose of this analysis is to assess how much our cost of service might increase if RPU was subjected to long term market energy price shocks. It should be reiterated that forward hedged energy contracts are not the only viable replacement option for IPP. However, the fundamental results from this analysis suggest that whatever replacement option(s) RPU elects to pursue will need to either have a well hedged fuel supply, or some other type of dependable, fixed cost structure. This characteristic needs to be present in any future option we consider, in order to effectively mitigate exposure to price uncertainty in the forward energy markets and minimize our long term risk profile.

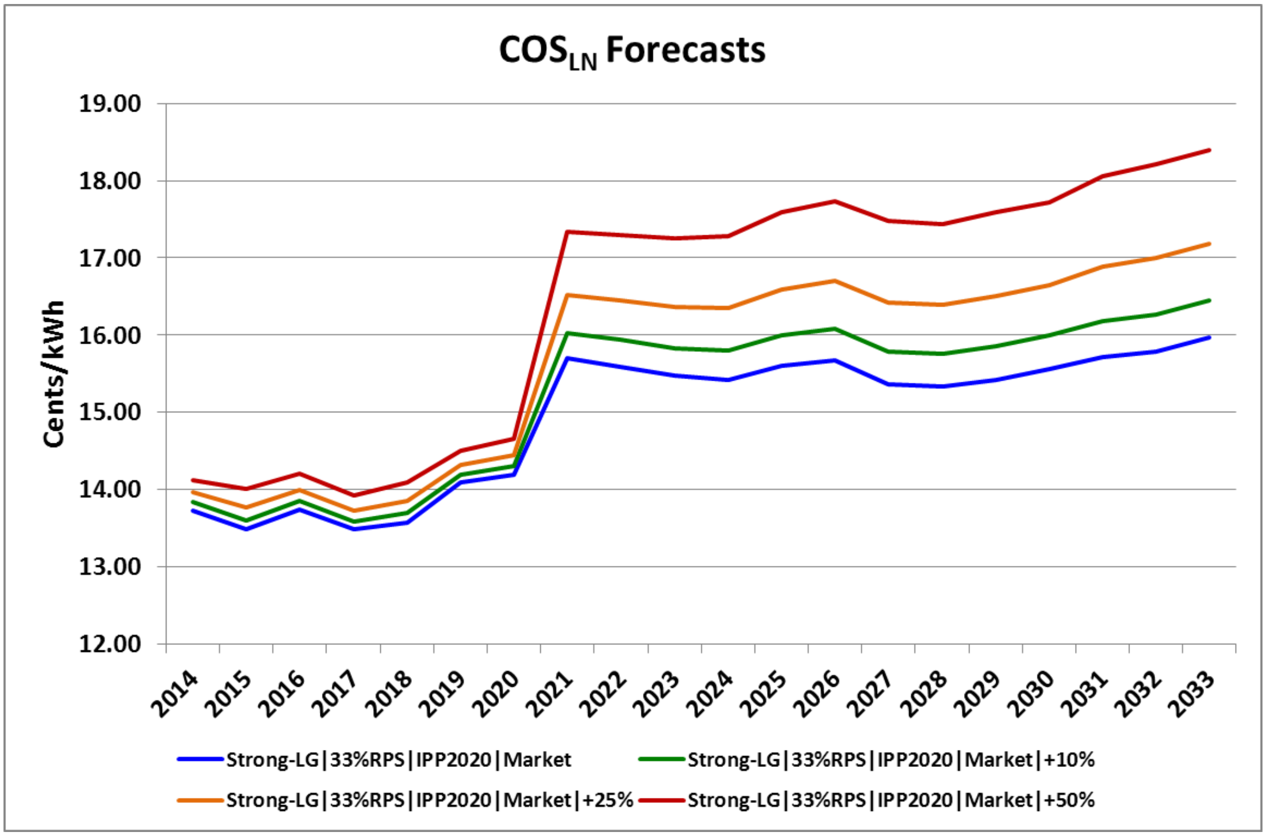


Figure 10.6.1. Projected annual COS$_{LN}$ estimates for a baseline configuration subject to three market price shock scenarios (10%, 25% and 50% power and natural gas price increases). Baseline assumptions are strong load growth, a 33% RPS mandate, a 2020 IPP contract termination date, and an IPP replacement option using unhedged market purchases.

Table 10.6.1. Figure 10.6.1 COS$_{LN}$ estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (annual growth rates and relative cost increases). All cost units shown in ₵/kWh.

Scenario	2018	2023	2028	2033	AGR%
A. Strong-LG|33%RPS|IPP2020|Market	13.571	15.472	15.336	15.962	1.0%
B. Strong-LG|33%RPS|IPP2020|Market|+10%	13.691	15.831	15.759	16.451	1.1%
C. Strong-LG|33%RPS|IPP2020|Market|+25%	13.852	16.366	16.390	17.182	1.3%
D. Strong-LG|33%RPS|IPP2020|Market|+50%	14.086	17.252	17.436	18.395	1.6%
Scenario B vs A	0.9%	2.3%	2.8%	3.1%	
Scenario C vs A	2.1%	5.8%	6.9%	7.6%	
Scenario D vs A	3.8%	11.5%	13.7%	15.2%	

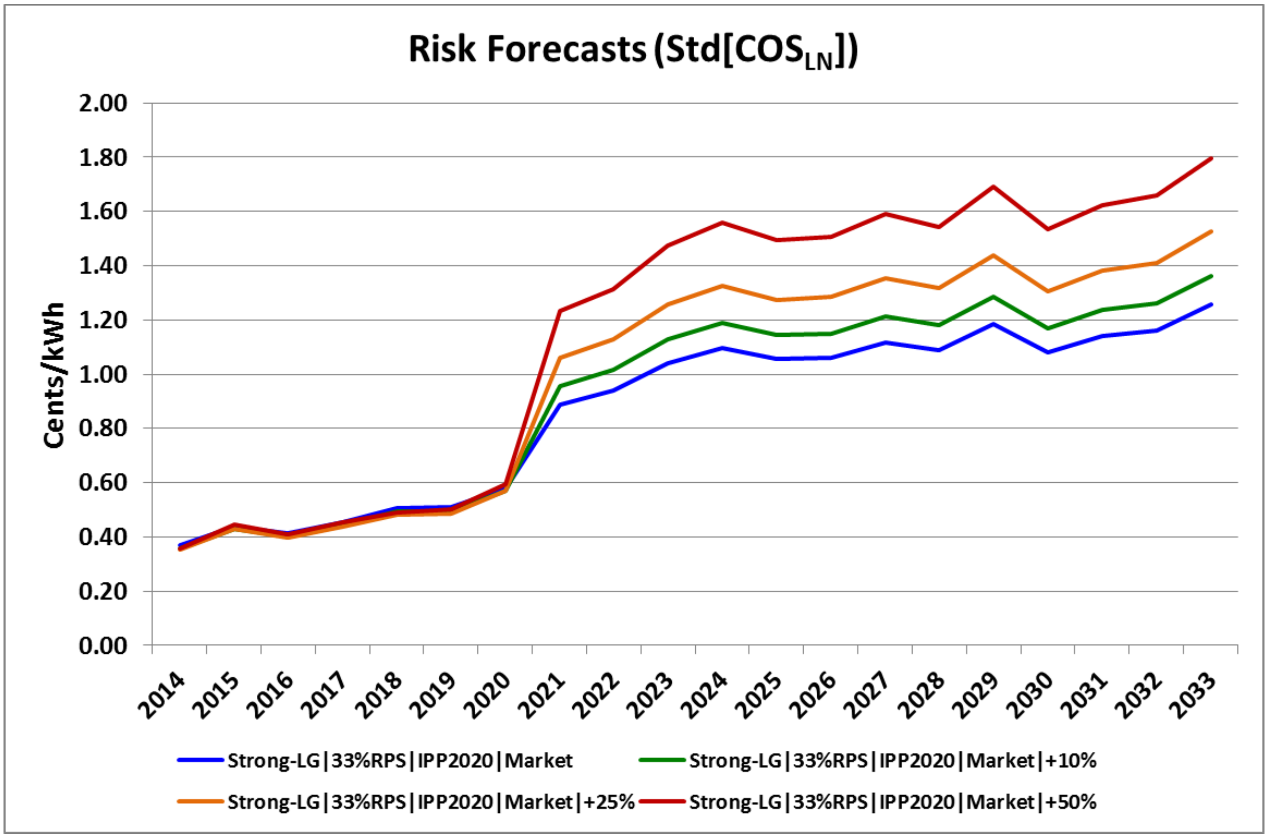


Figure 10.6.2. Corresponding annual COS$_{LN}$ risk estimates (Std[COS$_{LN}$]) for the baseline and three market price shock scenarios shown in Figure 10.6.1, assuming strong load growth, a 33% RPS mandate, a 2020 IPP contract termination date, and an IPP replacement option using unhedged market purchases.

Table 10.6.2. Figure 10.6.2 COS$_{LN}$ risk estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (relative risk levels). All cost units shown in ₵/kWh.

Scenario	2018	2023	2028	2033
A. Strong-LG|33%RPS|IPP2020|Market	0.506	1.042	1.088	1.255
B. Strong-LG|33%RPS|IPP2020|Market|+10%	0.492	1.128	1.180	1.363
C. Strong-LG|33%RPS|IPP2020|Market|+25%	0.482	1.258	1.316	1.525
D. Strong-LG|33%RPS|IPP2020|Market|+50%	0.489	1.474	1.544	1.795
Relative Risk of Scenario A	3.7%	6.7%	7.1%	7.9%
Relative Risk of Scenario B	3.6%	7.1%	7.5%	8.3%
Relative Risk of Scenario C	3.5%	7.7%	8.0%	8.9%
Relative Risk of Scenario D	3.5%	8.5%	8.9%	9.8%

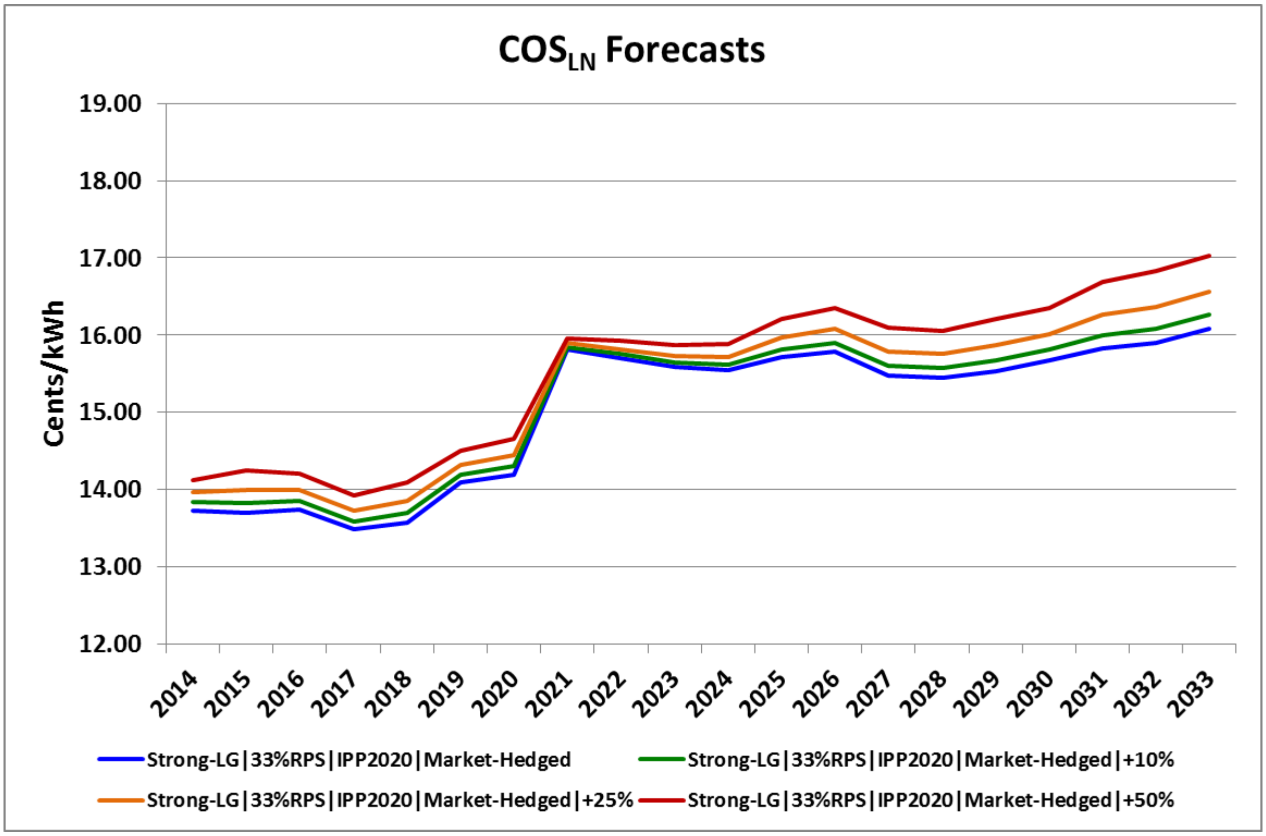


Figure 10.6.3. Projected annual COS_{LN} estimates for an alternative baseline configuration subject to three market price shock scenarios (10%, 25% and 50% power and natural gas price increases). Baseline assumptions are strong load growth, a 33% RPS mandate, a 2020 IPP contract termination date, and 150 MW of forward hedged energy contracts as an IPP replacement option.

Table 10.6.3. Figure 10.6.3 COS_{LN} estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (annual growth rates and relative cost increases). All cost units shown in ₵/kWh.

Scenario	2018	2023	2028	2033	AGR%
Strong-LG|33%RPS|IPP2020|Market-Hedged	13.571	15.588	15.451	16.079	1.0%
Strong-LG|33%RPS|IPP2020|Market-Hedged|+10%	13.691	15.648	15.575	16.271	1.1%
Strong-LG|33%RPS|IPP2020|Market-Hedged|+25%	13.852	15.734	15.759	16.558	1.1%
Strong-LG|33%RPS|IPP2020|Market-Hedged|+50%	14.086	15.873	16.058	17.029	1.2%
Scenario B vs A	0.9%	0.4%	0.8%	1.2%	
Scenario C vs A	2.1%	0.9%	2.0%	3.0%	
Scenario D vs A	3.8%	1.8%	3.9%	5.9%	

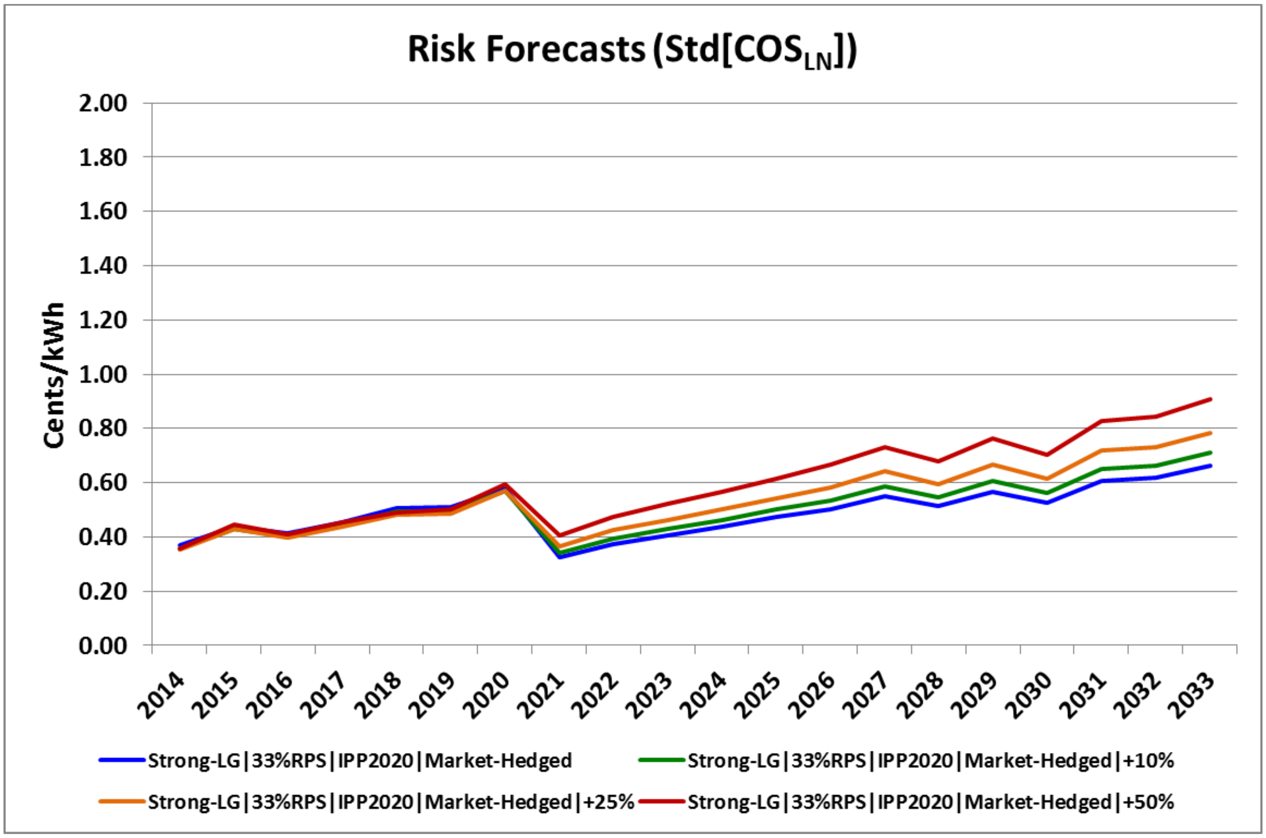


Figure 10.6.4. Corresponding annual COS_{LN} risk estimates (Std[COS_{LN}]) for the baseline and three market price shock scenarios shown in Figure 10.6.3, assuming strong load growth, a 33% RPS mandate, a 2020 IPP contract termination date, and 150 MW of forward hedged energy contracts as an IPP replacement option.

Table 10.6.4. Figure 10.6.4 COS_{LN} risk estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (relative risk levels). All cost units shown in ₵/kWh.

Scenario	2018	2023	2028	2033
Strong-LG|33%RPS|IPP2020|Market-Hedged	0.506	0.406	0.513	0.664
Strong-LG|33%RPS|IPP2020|Market-Hedged|+10%	0.492	0.428	0.546	0.712
Strong-LG|33%RPS|IPP2020|Market-Hedged|+25%	0.482	0.462	0.596	0.785
Strong-LG|33%RPS|IPP2020|Market-Hedged|+50%	0.489	0.520	0.678	0.906
Relative Risk of Scenario A	3.7%	2.6%	3.3%	4.1%
Relative Risk of Scenario B	3.6%	2.7%	3.5%	4.4%
Relative Risk of Scenario C	3.5%	2.9%	3.8%	4.7%
Relative Risk of Scenario D	3.5%	3.3%	4.2%	5.3%

10.7 Summary and Conclusions

Given the results presented in sections 10.3 through 10.5, it is possible to quantify both the magnitude and uncertainty surrounding each scenario. The panel graph shown in Figure 10.7.1 shows the expected, load normalized cost of service (COS_{LN}) estimates in 2023, 2028 and 2033 for the twelve resource planning scenarios examined here (i.e., our eight primary scenarios plus four additional scenarios where we've used hedged market purchases to replace our lost IPP power). These twelve scenarios have been ordered by their 2023 COS_{LN} estimates (from high to low). In addition to each estimate (shown as black diamonds), two standard deviations of uncertainty are also shown (blue and green vertical bars, respectively); these bars define the range of uncertainty associated with each COS_{LN} estimate. Note that the plots for 2023 and 2033 were shown previously in Figure 10.1.

As shown in Figure 10.7.1, our long term load growth projections represent the single greatest driver of our ultimate cost of service, while our hedging strategy represents the primary factor influencing the associated COS_{LN} uncertainty estimates. Tables 10.7.1 and 10.7.2 quantify the specific effects of each primary factor, respectively. Table 10.7.1 quantifies how much each studied factor adds to our baseline COS_{LN} costs in 2023, 2028 and 2033, while Table 10.7.2 quantifies how the corresponding uncertainty effects (standard deviations) change as these same factor levels are changed. More specifically, if RPU were to experience weak load growth over the next ten to twenty years, we should expect our COS_{LN} to increase by 1 to 2 ₵/kWh over this same time horizon. This is by far the single greatest influencing factor in determining our future COS_{LN} estimates; note the next largest impact is associated with an early IPP termination date (~ 0.5 ₵/kWh impact). In contrast, maintaining a 40% RPS and/or replacing IPP energy with hedged market purchases add relatively little to our forecasted future COS_{LN} estimates. Likewise, adopting a viable hedging paradigm adds little to our expected COS_{LN}, but greatly reduces the associated uncertainty around these estimates. The 40% RPS scenario also slightly reduces our COS_{LN} uncertainty estimates (as does weak load growth), although both of these impacts are relatively minor. Finally, if our IPP contract is terminated early (in 2021), our COS_{LN} should increase by about 0.5 ₵/kWh and the associated standard deviation would increase by about 0.3 ₵/kWh. However, if the replacement energy is forward hedged, then the expected standard deviation should decrease by approximately 0.4 ₵/kWh.

Overall, these results suggest that the following conclusions can be drawn from the long-term studies examined in this chapter.

- As made clear from the results shown in section 10.3 and Table 10.7.1, our assumed future load growth rate significantly impacts our future cost-of-service forecasts. Our COS_{LN} forecasts are 10% higher in 2028 and 13% higher in 2033 under a weak load growth assumption, as compared to the strong (healthy) assumption. In general, RPU has already reached a tipping point where our "all other" costs are growing much faster than our service area load level. Thus, reductions in our load growth rate will most likely translate into direct cost of service increases, unless the unrealized, avoided loads are highly strategic in nature.

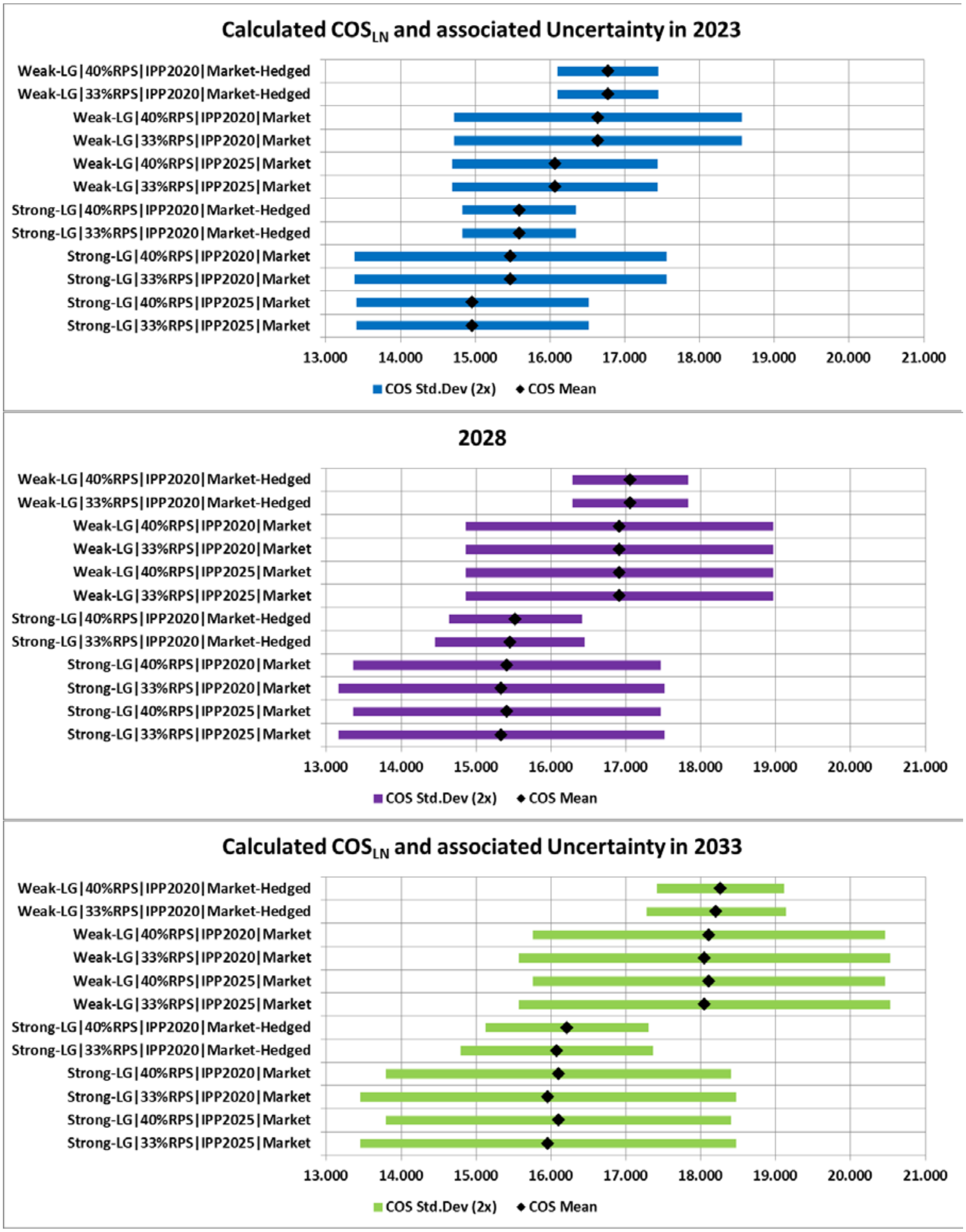


Figure 10.7.1. Forecasted 2023, 2028 and 2033 COS_{LN} values and corresponding risk estimates for the six IRP scenarios that all assume strong load growth and a December 31, 2020 IPP contract termination date. (Note: 2023 and 2033 panel plots shown previously in Figure 10.1.)

Table 10.7.1. Quantified impacts of each primary factor on RPU's projected COS_{LN} cost estimates. (Data also shown graphically in Figure 10.2.)

Scenario Input Factor	2023 Cost (14.94 ₵/kWh)	2028 Cost (15.35 ₵/kWh)	2033 Cost (15.97 ₵/kWh)
Weak Load Growth	1.16	1.55	2.06
40% RPS	0.00	0.04	0.10
IPP ends in 2021	0.54	0.00	0.00
Hedged market purchases	0.13	0.13	0.14

Table 10.7.2. Quantified impacts of each primary factor on RPU's projected COS_{LN} uncertainty estimates. (Data also shown graphically in Figure 10.2.)

Scenario Input Factor	2023 Std (0.77 ₵/kWh)	2028 Std (1.08 ₵/kWh)	2033 Std (1.27 ₵/kWh)
Weak Load Growth	-0.07	-0.05	-0.05
40% RPS	0.00	-0.03	-0.08
IPP ends in 2021	0.27	0.00	0.00
Hedged market purchases	-0.38	-0.61	-0.69

- In contrast to the load growth impact discussed above, we project that RPU can reach and maintain a 40% RPS mandate with relatively minimal rate impacts (i.e., < 1%), at least under the assumptions considered here. Contract prices for renewable energy generation have fallen significantly in the last few years; a number of renewable contracts can now be obtained in the $65/MWh to $80/MWh price range. Given that the "all-in" thermal energy generation costs are around $60/MWh in our current portfolio, the purchase or contracting of additional renewable energy assets certainly represents one viable future procurement strategy, assuming that their pricing structure remains attractive and that the corresponding energy can be effectively used to hedge our load serving needs.

- As discussed in sections 10.3 and 10.4, the timing of our IPP contract termination date will also significantly impact our future cost of service. We currently project a 0.5 ₵/kWh to 0.6 ₵/kWh cost increase associated with an early (non-voluntary) IPP contract termination event. Additionally, we currently project a 1.0 ₵/kWh to 1.1 ₵/kWh cost increase due to the loss of free Carbon emission credits on/after 2021.

- From a strictly economic perspective, it does not make sense to try and unilaterally abandon our IPP contract any earlier than necessary. Rather, we should continue to support a market driven dispatch scheme that recognizes the inherent Carbon cost embedded in this energy asset, while searching for a replacement option that can come online within the 2021-2026 time-frame. It should be noted that this strategy could change in the future, should Carbon emission costs rise significantly above their current long-term forecasted levels. However, under a high emission cost scenario, a market driven dispatch approach will naturally ramp down our IPP energy anyway, so there is little downside risk to continuing to employ this type of dispatch strategy.

- Finally, as demonstrated by the analysis of the section 10.6 price shock studies, our IPP energy will need to be replaced with some type of fixed price generation asset or long-term, forward hedged energy contract(s), if we wish to contain our future portfolio risk at an acceptable level. From a risk perspective, RPU cannot afford to leave such a large base-load energy position open and exposed to significant SP15 day-ahead market price movements; the resulting cash-flow uncertainty will simply be too severe.

11. Alternative Portfolio Analyses: Part I – Additional IPP Replacement Options

In Chapter 10 we examined the projected cost impacts of twelve different resource planning scenarios (i.e., eight primary scenarios plus four additional scenarios where hedged market purchases were used to replace our lost IPP power). This cost assessment considered both the expected values and simulated standard deviations of RPU's full cost of service for electric services. As shown by these analyses, the market hedged scenarios were the preferred IPP replacement alternatives from the perspective of minimizing our future COS_{LN} uncertainty.

In this chapter we examine five alternative generation replacement scenarios that could represent reasonable IPP replacement options, and compare these new scenarios to a market hedged scenario. The costs associated with these new generation scenarios are more uncertain and therefore need to be separately considered from the scenarios considered in Chapter 10. The five alternative replacement options examined here are as follows: (A1) new internal generation: a 100 MW GE LMS-100 high-efficiency, simple cycle gas plant, (A2) new internal generation: five 9.3 MW Wartsila 20V34SG simple cycle internal combustion units, stacked together into a 46.5 MW generation facility, (B) a decision to participate in and purchase 50 MW of the 1,000 MW IPP Repower Project, (C) replacing 75 MW of the IPP coal energy with a new long term renewable contract, and (D) the acquisition of a near-term 150 MW commercial tolling contract (beginning in January 2016). Each of these alternatives is discussed in more detail in section 11.2.

11.1 High-level Overview of Alternative Scenarios

Before describing our alternative replacement options in detail, a review of three pertinent input assumptions are in order. First, the same simulation methodology described in chapter 10 has been used to perform these alternative scenario assessments; i.e., after specifying a specific replacement option, the corresponding COS_{LN} estimates are used to facilitate an effective comparison between the alternative options. Second, alternatives A1, A2, B and C also include additional forward hedged market purchases in order to normalize each scenario (and associated COS_{LN} estimates) into a 150 MW energy replacement option. This latter assumption is necessary in order to facilitate equivalent comparisons of the COS_{LN} risk estimates, since only one of the five alternative replacement options considered here individually supplies a full 150 MW of replacement base-load energy. Third, a 33% RPS and strong load growth are assumed in both the baseline and all alternative scenarios, along with an early (December 31, 2020) IPP contract end-date.

A high-level description of each alternative scenario is shown in Table 11.1.1. Likewise, Table 11.1.2 quantifies all of these various scenarios with respect to the following meta-attributes: size, location, technology, flexibility, and permitting/emission issues. It is worthwhile to note that RPU would most likely need a five year lead time to develop any new internal generation assets in Riverside. Ideally, RPU should also begin implementing an IPP replacement, forward market hedging strategy four to five years before the end of the IPP contract, although strategies with shorter lead times can also obviously be implemented. In principal, a tolling contract could be signed just one year before the IPP contract end-date. However, in this analysis, we assume that the tolling contract begins in 2016 in order to examine the plausibility of implementing this replacement scenario at current market pricing (for typical tolling contracts within the CAISO balancing area).

Additionally, it is worthwhile to emphasize that Alternative C specifically examines a base-load renewable resource, as opposed to a non-base-load (and/or intermittent) resource. In particular, we explicitly have avoided examining an all-solar PV replacement option, since the diurnal energy production shape is significantly misaligned with our expected load serving needs. Figure 11.1 shows how 500 MW of utility scale solar PV with a 30% CF would impact our post-IPP resource stack, and why it cannot effectively be used to replace our base-load IPP coal resource. The diurnal misalignment with our expected wholesale load serving needs is significant, and the associated budgetary cash-flow risk would be substantial.

Table 11.1.1. Baseline and alternative IPP replacement options.

Scenario	Description	Additional Notes
Baseline	150 MW of forward hedged, market power contracts	see Section 10.1
Alternative A1	New Internal Generation: 100 MW GE LMS-100 High-efficiency simple cycle gas plant, 7,815 HR, dispatchable from 0 to 100 MW	Includes a 50% long-term forward fuel hedge, + a long-term 50 MW forward power hedge
Alternative A2	New Internal Generation: 46.5 MW Wartsila 20V34SG simple cycle internal combustion unit, 8,308 HR, dispatchable from 0 to 46.5 MW	Includes a 50% long-term forward fuel hedge, + a long term 103.5 MW forward power hedge
Alternative B	Participate in IPP Repower Project: 50 MW of NGCC: 7,000 HR, dispatchable from 20 to 50 MW	Includes a 75% long-term forward fuel hedge, + a long-term 100 MW forward power hedge
Alternative C	New 75 MW base-load Renewable Energy contract (PPA)	Also includes a long-term 75 MW forward power hedge
Alternative D	150 MW Tolling Contract, beginning on January 1, 2016	Includes a 92% long-term forward fuel hedge upon IPP retirement

Table 11.1.2. Meta-attributes for all IPP replacement options.

Scenario	Capacity (MW)	Physical Location	Fuel Technology	Dispatch Flexibility	Permitting challenge
Baseline	150	n/a (market)	Non-specified	None	n/a (None)
Alternative A1	100	Riverside, CA	Natural Gas	High	High
Alternative A2	46.5	Riverside, CA	Natural Gas	High	High
Alternative B	50	Utah	Natural Gas	Moderate	Moderate
Alternative C	75	CA	Renewable	Low	Low
Alternative D	150	CA (CAISO)	Natural Gas	Moderate	Low

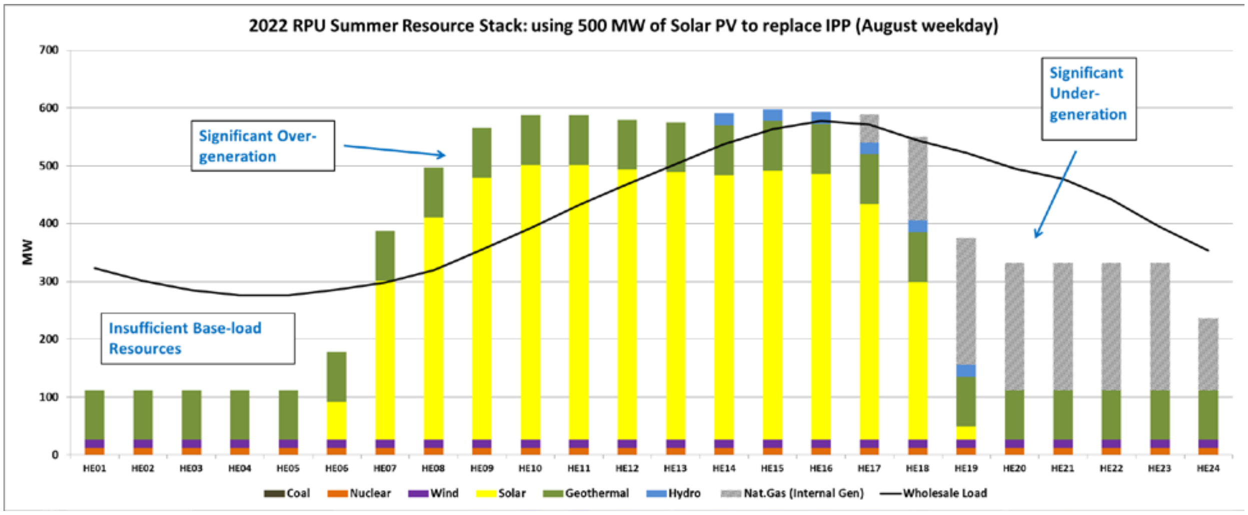


Figure 11.1. Diurnal miss-match between solar PV energy generation and RPU post-IPP load serving needs (500 MW solar PV asset, 30% CF).

Finally, as in our previous analyses, 100 simulation runs have been performed for each alternative scenario shown in Table 11.1.1. These simulations allow us to quantify both the expected annual load serving costs and the associated uncertainty (i.e., standard deviation) surrounding these cost estimates. Likewise, these simulation runs have been performed at the hourly granularity over the same twenty year timeframe (January 1, 2014 through December 31, 2033), using the same set of input forward price curves. Furthermore, all of the additional, fixed costs discussed in sections 10.2.1 through 10.2.8 have also been applied to these alternative scenarios in order to facilitate a consistent set of comparisons.

High-level Summary of Results

As in Chapter 10, it is useful to briefly summarize our pertinent study findings before delving into all of the details concerning our modeling inputs, assumptions, and analyses. The panel graph shown in Figure 11.2 shows the expected, load normalized cost of service (COS_{LN}) estimates in 2023 and 2033 for both the baseline and five IPP replacement scenarios examined here. These six scenarios have been ordered by their 2023 COS_{LN} estimates (from high to low). In addition to each estimate (shown as black diamonds), two standard deviations of uncertainty are also shown (blue and green horizontal bars, respectively); these bars define the range of uncertainty associated with each COS_{LN} estimate. As compared to the baseline scenario, four of the five IPP replacement scenarios result in an increased cost of service, and all five replacement scenarios result in higher associated COS_{LN} uncertainty estimates. Thus, with respect to a risk minimized COS_{LN} criteria, none of the alternatives considered here outperform the baseline option of using forward hedged, market power contracts to replace our IPP contract.

A more detailed and exhaustive discussion of these results is presented in section 11.3, respectively.

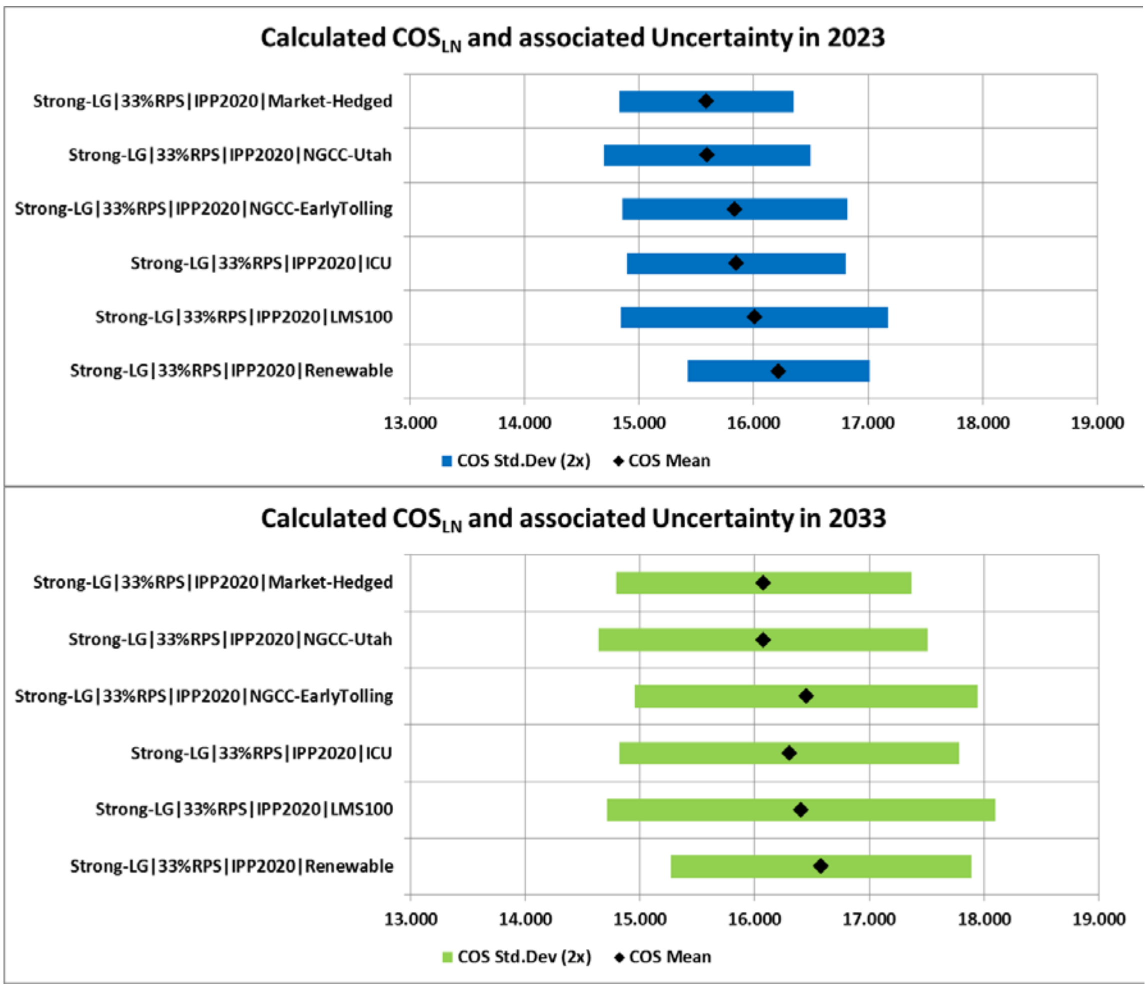


Figure 11.2. Panel plots of forecasted COS_{LN} and associated uncertainty (± 2 standard deviations) in 2023 (upper plot) and 2033 (lower plot), for six IPP contract replacement options.

11.2 Alternative IPP Replacement Options

11.2.1 New Internal Generation (GE - LMS100 or Wartsila 20V34G)

The first two alternative IPP replacement scenarios considered here are new internal generation assets. Under these scenarios, RPU would commission a contractor to build either a high efficiency, simple cycle gas turbine (SCGT) unit, or a modular deployment of internal combustion units (ICUs) on a site within Riverside. An SCGT unit tends to be slightly more efficient, but the ICUs are more scalable. In practice, either unit would most likely be located at the Springs generation site, although a new unit could also be sited at the Riverside Energy Resource Center (RERC). RPU already owns these sites, which is likely to facilitate the permitting process.

In this analysis, we assume that the new generation will be built at the Springs site. This site seems particularly suitable given that our four GE-10 units are outdated and highly inefficient. These units have been effectively phased-out of the power generation business; they are maintenance-prone, costly to repair, and unlikely to meet current and future SCAQMD's regulations. Furthermore, new generation at the Springs site would also significantly contribute to the reliability and distribution operational flexibility of the eastern half of the RPU distribution system.

For this study specifically, two different hypothetical generation plants are considered to assess the impact of building a new generation asset to replace the Springs GE-10 units – (A1) a GE LMS100 gas turbine and (A2) five Wartsila 20V34SG ICU's. These two plants are considered because their operational characteristics seem particularly suitable to meet RPU's operational needs in the future. For instance, both have fast start and load following capabilities, which are expected to become particularly important and needed, given the CAISO's new flexible capacity requirements for integrating large amounts of intermittent resources. Additionally, both plants are highly efficient and would produce less air emissions for the same fuel input. These latter features will be especially important under increasingly stringent local, state and federal air emissions laws/regulations, e.g., SCAQMD's regulations and the CARB's GHG Cap-and-Trade regulations. The specific operating characteristics of each plant are discussed in detail below.

GE LMS100

GE's LMS100 is a 100 MW simple cycle gas turbine system with a wide range of operating flexibility for power generation. The LMS100's notable features and benefits include:

- Fast start capability and full power within ten minutes
- Load following and cycling capabilities
- No maintenance penalties for cycling
- Water injection NOx emission control
- Thermal efficiency in excess of 44%
- Excellent hot day performance

In order to properly model this new hypothetical LMS100 generation asset in the Ascend Production Cost Software, assumptions concerning the unit's performance specifications, Engineering Design and Construction (EDC) costs, financing, and construction time must be made. These additional assumptions are as follows.

Performance Specifications

The specific LMS100 unit examined in this analysis is the LMS100-PA aeroderivative gas turbine package with water injection for NOx emission control. Its particular performance specifications – as presented on the GE Energy website – are shown in the Table 11.2.1 below.

Table 11.2.1. LMS100-PA aeroderivative performance specifications.

Output Power:	103 MW
Efficiency:	44%
Low Pressure Turbine Speed:	3600 RPM
Emission:	25 ppm NOx
Emissions Control:	Water Injection
Heat Rate:	7815 Btu/kWh
Exhaust Temperature:	760 degrees F
Exhaust Flow:	480 pounds/second

EDC Costs and Financing

Estimates for the capital construction and O&M costs come from a Black and Veatch study entitled "*LM6000 and LMS100 Characterization"* that was filed with the Colorado Public Utilities Commission in July 2011. These cost estimates have been adjusted to reflect Riverside's specific assumptions – namely, that the hypothetical LMS100 will:

- Come online on January 1, 2021
- Replace the Springs Generation Facility
- Be sited at the existing Springs site
- Require South Coast Air Quality Management District (SCAQMD) emissions credits

Both the cost estimates and notes concerning specific cost adjustments are shown in Table 11.2.2. Additionally, the total construction cost of the new LMS100 is assumed to be financed with a RPU bond issuance. The specific assumptions about the bond issuance are presented in Table 11.2.3.

Table 11.2.2. LMS100 engineering, design, construction and O&M cost assumptions.

Variable	2021 Estimate	Adjustment Description
Capital Costs	$119,000,000	No adjustment
Owner Costs	$21,000,00	Owner's cost reduced 30% on account of existing land and infrastructure
Total Costs	$140,000,000 ($1,400/kW)	
Emission Credits	$10,000,000	SCAQMD will require RPU to procure emission credits
Fixed O&M	$18.65/kW-year	Escalated 2% per year to account for inflation
Variable O&M	$5.49/MWh	Escalated 2% per year to account for inflation

Table 11.2.3. LMS100 bond financing assumptions.

Bond Issue Date	January 1, 2018
Construction Schedule	3 years
Total Cost **Capitalized Interest** **Emission Credits** **Par Amount**	$140,000,000 $26,470,588 $10,000,000 $176,470,588
Bond Interest Rate	5%
Bond Maturity	25 years
Debt Service Structure	Level
RPU's Annual Debt Service	$12,521,022

Wartsila 20V34SG ICU

Wartsila's 20V34SG unit is a 9.3MW simple cycle ICU with a wide range of operating flexibility for power generation. The 20V34SG's notable features include:

- Scalable modular units
- Fast start capability and full power within five minutes
- Load following and cycling capabilities
- No maintenance penalties for cycling
- Low water usage (approximately one gallon per unit per week)
- Thermal efficiency in excess of 49%
- Fast construction time (12-18 months)

Performance Specifications

This analysis assumes that five Wartsila 20V34SG 9.3 MW units will be built on the existing Springs site for a total of 46.5 MW. The Wartsila 20V34SG's performance specifications are shown in Table 11.2.4 below.

Table 11.2.4. Wartsila 20V34SG performance specifications.

Output Power:	46.5 MW (5 x 9.3 MW)
Minimum Power:	4 MW
Heat Rate:	8308 Btu/kWh
Ramp Rate:	40 MW/min
Efficiency:	49%
NOx Emissions:	5 ppm
CO2 Emissions:	120 lbs/mmBtu

EDC Costs and Financing

Estimates for the capital construction and O&M costs come from Wartsila. These cost estimates have been adjusted to reflect Riverside's specific assumptions as discussed above. Both the cost estimates and notes concerning specific cost adjustments are shown in Table 11.2.5. Additionally, the total construction cost of the Wartsila 20V34SG units is assumed to be financed with an RPU bond issuance. The specific assumptions about the bond issuance are presented in Table 11.2.6.

Table 11.2.5. Wartsila 20V34SG engineering, design, construction and O&M cost assumptions.

Variable	2021 Estimate	Adjustment Description
Capital Costs	$60,450,000 ($1,300/kW)	No adjustment
Emission Credits	$5,000,000	SCAQMD will require RPU to procure emission credits
Fixed O&M	$32.11/kW-year	Escalated 2% per year to account for inflation
Variable O&M	$4.25/MWh	Escalated 2% per year to account for inflation

Table 11.2.6. Wartsila 20V34SG bond financing assumptions.

Bond Issue Date	January 1, 2018
Construction Schedule	3 years
Total Cost **Capitalized Interest** **Emission Credits** **Par Amount**	\$60,450,000 \$11,550,000 <u>\$5,000,000</u> \$77,000,000
Bond Interest Rate	5%
Bond Maturity	25 years
Debt Service Structure	Level
RPU's Annual Debt Service	\$5,463,339

Other Assumptions

Due to the three-year construction schedule, it is assumed that the GE-10 units would be retired by January 1, 2018. In turn, this implies that the RPU portfolio will temporarily lose 36 MW of RA capacity in 2018, 2019 and 2020. Our expected 2018-2033 RA costs have been updated accordingly to reflect these increased RA costs during this three year transition period.

In order to consistently model 150 MW of energy needed in the portfolio, we additionally assume that with both generation options, RPU procures a long-term forward 7x24 power contract at an annual fixed price that is equal to the expected forward SP15 energy price curve, plus a 4% price adder – specifically, 50 MW with the LMS100 and 103.5 MW with the five Wartsila 20V34SG units. This assumption will allow us to isolate the effects of the new internal generation asset on the associated COS_{LN} uncertainty estimate; i.e., any increase in this risk metric will be solely attributable to the uncertainty associated with the cost and revenue profile of the new generation. Finally, we also assume that RPU procures a long-term forward contract for natural gas, purchased at a price equal to the current expected long-run average annual forward Citygate price curve, plus a 4% price adder. For the LMS100 and the five Wartsila 20V34G units, the forward natural gas contract was for 9,378 MMBtu/day and 4,656MMBtu/day, respectively (i.e., a 50% fuel hedge). Under simulation, the LMS100 and Wartsila units exhibited a monthly CF at/below 50%, thus we have assumed that a partial fixed-price fuel hedge of 50% represents the most reasonable hedging strategy for these resources.

11.2.2 IPP Repower Option: 50 MW Investment

There are ongoing discussions among the IPP participants to replace the IPP coal units with a natural gas combined cycle (NGCC) generator on or before the expiration of current Power Sales Contract (PSC) for IPP in 2027. RPU has expressed interest in contracting for up to 50 MW of capacity in this replacement NGCC project (i.e., the "IPP Repower Project"). This analysis does not prejudge whether RPU will ultimately participate in the Repower Project. Rather, it simply attempts to quantify the primary cost impacts associated with participating, in order to better facilitate senior management's ultimate decision making process for the Repower Project.

While there is reasonable certainty concerning the technology type, other specific details about the project, including total capacity, performance specifications and costs, have yet to be determined. Therefore, similar to the hypothetical LMS100 generation asset, additional assumptions are made to effectively model the Repower Project in the Ascend Production Cost software environment. These various assumptions are discussed in detail below.

Performance Specifications

As a replacement for IPP, we assume that the Repower Project will primarily serve the same base-load function but offer higher efficiency and more ramping flexibility. Based on the information from the ongoing preliminary discussions, the Repower Project is assumed to have a total rated capacity of 1000 MW and a 7,000 Btu/kWh heat rate. Additionally, similar to the current IPP agreement, RPU will likely be one of several participants in the Repower Project. Due to this expected similarity in contractual structure, we assume that RPU will be able to at least operate the Repower Project in a similar way it currently operates IPP; i.e., where RPU can ramp its power output up and down hourly within a contractually specified range of 40% to 100%. Thus, we assume that RPU's share of the Repower Project output can be ramped on an hourly basis from 20 to 50 MW in response to market conditions.

EDC Costs and Financing

EDC cost estimates for the Repower Project come from two sources – estimates for the capital cost are derived from a presentation given at an LADWP Generation Subcommittee meeting on August 3, 2012; estimates for all other operating costs come from the EIA's "*Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants"* published April 2013. Similar to the cost estimates for the LMS100, these base cost estimates have been adjusted to reflect added assumptions, particularly, that the Repower Project will:

- Come online January 1, 2021
- Not require emission credits
- Procure natural gas at a Utah point-of-delivery ($0.50/MMBtu less than SoCal Citygate)

These estimates, along with a description of any adjustments, are shown in Table 11.2.7.

Table 11.2.7. IPP NGCC engineering, design, construction and O&M cost assumptions.

Variable	2021 Estimate	Adjustment Description
Capital and Owner Costs	$1,000,000,000 $1,000/kW	No adjustments
Emission Credits	N/A	No adjustments
Fixed O&M	$15.51/kW-year	Escalated 2% per year to account for inflation
Variable O&M	$4.24/MWh	Escalated 2% per year to account for inflation
Fuel	Citygate - $0.50/MMBtu	SoCal Citygate forward fuel prices reduced to reflect a lower Utah basis

The total construction cost of the Repower Project is assumed to be financed with a bond issuance by either the current IPP project owner, the Intermountain Power Agency (IPA), or a Joint Powers Authority like the Southern California Public Power Authority (SCPPA). Participants in the Repower Project will be obligated to pay debt service related to any bond issuance proportional to their respective output share. In this analysis, RPU incurs debt service costs based on a 50/1000 or 5% share. The specific assumptions about the bond issuance are presented in Table 11.2.8 below.

Table 11.2.8. Repower Project financing assumptions.

Bond Issue Date	January 1, 2018
Construction Schedule	3 years
Capital Cost **Emission Credits** **Capitalized Interest** **Par Amount**	$1,000,000,000 $0 $176,470,588 $1,176,470,588
Bond Interest Rate	5%
Bond Maturity	25 years
Debt Service Structure	Level
Total Project Annual Debt Service	$83,473,479
RPU's Annual Debt Service Obligation	$4,173,674

Other Assumptions

Again, in order to consistently model 150 MW of needed energy in the portfolio, we assume that RPU will procure a long-term 100 MW forward 7x24 power contract at an annual fixed price that is equal to the expected forward SP15 energy price curve, plus a 4% adder. As before, this assumption will allow us to isolate the effects attributable to the Repower Project on the associated COS_{LN} uncertainty estimate; i.e., any increase in this risk metric will be solely due to the uncertainty associated with the cost and the revenue profiles of the Repower Project. Finally, we assume that RPU procures a long-term forward fixed price contract for 6,300 MMBtu/day of natural gas (i.e., a 75% fuel hedge). This gas price is discounted by $0.50/MMBtu below SoCal city gate price (+ the 4% price adder) to reflect the current basis differential between Utah and SoCal. Under simulation, the Repower Project exhibited average quarterly CF's from 58% to 76%, thus a 75% fuel hedge represents a reasonable assumption for this scenario. Likewise, the basis differential of $0.50 is based on an analysis of recent regional natural gas pricing trends (see Appendix F).

11.2.3 New 75 MW Base-load Renewable Energy Contract

As a fourth option, we also examine a scenario where a long-term 75 MW base-load renewable energy contract is used to replace the expiring IPP contract. This renewable energy contract is assumed to follow a standard take-and-pay PPA, and provide 75 MW of additional renewable energy into the RPU portfolio on a 7x24 basis. The $/MWh price for this energy is assumed to be identical to our new CalEnergy geothermal contract ($78.48/MWh in 2021, with a 1.5% annual escalation rate). The specific renewable resource is left unspecified, but in practice would most likely consist of either a geothermal or biomass generation asset, located somewhere within the WECC transmission system. Due to the locational uncertainty associated with this generation asset, we assume that this renewable energy contract does not have any RA attributes.

Again, in order to consistently model 150 MW of needed energy in the portfolio, in this fourth scenario we also assume that RPU procures a long-term 75 MW forward 7x24 power contract (at an annual fixed price that is equal to the expected forward SP15 energy price curve, plus a 4% adder). Given the fixed price nature of both contracts and the absence of any additional RA attributes, the associated COS_{LN} uncertainty estimates for this scenario should be identical to our baseline comparison scenario; i.e., the forward fuel hedged, 150 MW tolling contract.

This scenario is of particular interest if RPU wishes to position itself to exceed more stringent future RPS mandates, e.g., no less than 50% by 2030. For example, if RPU were to enter into 75 MW of new renewable energy contracts in 2021, our expected 2021 RPS percentage would reach 60%. Additionally, RPU would remain above a 50% RPS until at least through 2027 and accumulate significant excess procurement credits, thus ensuring that we most likely exceed a 50% by 2030 RPS mandate.

11.2.4 150 MW Tolling Contract beginning January 1, 2016

Responses to a recent SCPPA Request For Information (RFI) for Coal Replacement revealed that existing natural gas combined cycle plants have long-term tolling options available to contract almost immediately. Therefore, as a final option, we examine a scenario where RPU enters into a long term tolling contract beginning January 1, 2016, thereby securing a replacement for IPP well in advance of IPP's anticipated retirement date.

Based on information gathered through the SCPPA Coal Replacement RFI, we modeled the hypothetical toll with the following assumptions.

Performance Specifications

The 150 MW tolling contract is assumed to come from an existing large natural gas combined cycle (NGCC) plant located in the CAISO system. The hypothetical plant has upwards of 750 MW of total output capacity, which counts as system RA, and a 7,340 Btu/kWh heat rate. Since 150 MW is characteristically the minimum output of one of these large NGCC plants, we assume that the plant dispatches economically to the market and provides no ramping capability between 0 MW and 150 MW, i.e. the NGCC is either on and producing 150 MW, or off.

Costs

The cost assumptions for the 150 MW tolling contract are presented in Table 11.2.9 below.

Table 11.2.9. NGCC Tolling cost assumptions.

Variable	2016 Cost	Notes
Capacity Payment	$7.45/kW-month	Escalates @ 3% per year
Variable O&M	$3.01/MWh	Escalates @ 3% per year
Start Charge	$3,016/Start	Escalates @ 3% per year

Other Assumptions

Acquiring a 150 MW tolling contract well in advance of IPP's anticipated retirement date would cause RPU to have substantial excess capacity (and potential energy production) until IPP retires (December 31, 2020 or December 31, 2025 as studied in this IRP), essentially requiring RPU to act as a quasi-merchant generator in the CAISO market. While acting in such a capacity, we assume that RPU does not procure a long-term forward fixed price fuel contract for the toll. However, upon IPP's retirement, we assume RPU does procure a long-term forward fixed price contract for 24,252 MMBtu/day of natural gas (i.e., a 92% fuel hedge). Additionally, we assume that RPU will be responsible for carbon emissions associated with this tolling contract's generation; the assumed carbon emissions factor for the plant is 0.39 metric tons per MWh.

Finally, since it is common for tolling contracts to include RA attributes, we assume that this contract also supplies RPU with 150 MW of annual system RA benefits. Given that RPU would be effectively long in RA credits for most of the calendar year under this scenario, we also assume that RPU sells off the excess monthly RA amounts (at pricing equal to our current forward system RA cost assumptions). These excess RA revenue streams are assumed to flow back into the budget, thus lowering the overall annual COS_{LN} estimates.

11.2.5 Options Not Considered in these Analyses

It is worthwhile to note that there are two additional IPP replacement options that may be worth considering, but which have not been included in these additional generation scenario analyses. Both of these options focus on the use of a high efficiency, combined cycle natural gas (CCNG) unit to meet our IPP replacement needs. However, unlike our tolling contract scenario, each of these scenarios consider CCNG ownership options.

The first alternative scenario not considered here would be to engineer, design and construct a smaller scale CCNG directly within the RPU service territory (most likely using either a 1-on-1 or 2-on-1 LM6000 design specification). While this is certainly a plausible scenario to examine, it is not considered here because such a CCNG plant would not fit into the current footprint of the Springs generation station. Additionally, RPU does not serve the water to the Springs station (and this station is severely water use-limited). Thus, if RPU were to build a new CCNG unit in its service territory, this unit would need to be developed on a different site; most likely new land. This raises a series of secondary cost issues; e.g., building or obtaining sufficient natural gas and/or water pipeline infrastructure, performing significant environmental impact studies, possibly purchasing land, etc. The Planning unit is not in the position to evaluate or quantify such costs at this time (such costs are highly site specific); thus this scenario will not be considered further here.

The second alternative scenario not considered here would be to purchase an existing CCNG plant at a significantly reduced price (i.e., a distressed asset sale). Some options may currently exist to purchase existing plants (or individual units within larger plants) at around $500/kW, which is substantially below the current cost to build a new facility. However, although this again represents a theoretically plausible scenario to examine, such a strategy would place RPU well outside of its historical and current utility operating strategy. Acquiring a 150 MW CCNG plant would cause RPU to acquire substantial excess capacity (and potential energy production) for at least the next five years; essentially requiring us to become a full-fledged merchant generator in the CAISO market. Given the magnitude of the shift in utility operating strategy that such a purchase would entail, we have elected to not include this option in the current set of scenario analyses.

11.3 COS_{LN} Analysis and Results

Figure 11.3.1 shows our projected annual COS_{LN} estimates (shown in ₵/kWh units) for both the baseline and five IPP replacement scenarios discussed in section 11.1, assuming strong load growth, a 33% RPS mandate, and a 2020 IPP contract termination date. Note that the “Baseline” scenario represents the 150 MW of forward market hedged contracts, previously discussed and analyzed in section 10.5. Additionally, Table 11.3.1 shows the corresponding COS_{LN} estimates for years 2018, 2023, 2028 and 2033, respectively, and summarizes some relevant scenario comparisons. More specifically, the annual COS_{LN} growth rate for each scenario is shown in the last column, and the bottom five rows quantify pertinent percent cost increases for the five generation alternatives, in comparison to the baseline market hedging scenario.

The results shown in Figure 11.3.1 and Table 11.3.1 suggest that from a COS_{LN} perspective, the 50 MW Repower Project (“NGCC-Utah”) option is essentially equivalent to the baseline market hedging scenario. In other words, we would expect our cost of service to be approximately equal under either scenario. In contrast, building our own internal generation units (“ICU” and “LMS100”) would raise our cost of service by about 1.5% to 2.5% above the market hedging option. An early tolling option (“NGCC-EarlyTolling”) also results in about a 2% cost of service increase, but note that this cost increase starts much earlier (i.e., in 2016). Finally, procuring 75 MW of additional base-load renewable energy would raise our cost of service by 3.5% to 4.5%, and thus represents the most expensive alternative.

The other important features shown in Figure 11.3.1 are the abrupt cost increases that occur in 2021. A 1.5 ₵/kWh to 2.0 ₵/kWh cost of service increase in 2021 will be unavoidable if our IPP contract terminates on January 1, 2021, and if no further emission compliance instruments are freely allocated after 2020.

Figure 11.3.2 shows the projected annual COS_{LN} uncertainty estimates (Std[COS_{LN}], again shown in ₵/kWh units) for the six corresponding scenarios shown in Figure 11.3.1. The baseline (market hedges) and renewable PPA scenarios provided the greatest (and equivalent) risk reduction after 2020. Both the ICE internal generation scenario and the Repower Project are also effective at reducing the COS_{LN} uncertainty estimates to nearly the same degree. However, it should be noted that the risk profiles associated with both of these options also benefit from being combined with large, forward hedged power purchases; i.e., ~ 100 MW market hedges. There is proportionally less risk reduction achieved by building an LMS100 unit, primarily because only 50% of the potential LMS100 generation energy is forward hedged in this scenario.

Interestingly, the early tolling option creates a lower risk profile before 2020, since it acts like a heat-rate call option for our entire load serving needs before 2020. After 2020 it is not quite as effective as some of our other generation options, although its risk profile remains fairly reasonable throughout the simulated time horizon. However, some additional caveats are in order here. Figure 11.3.3 and Table 11.3.3 shows our projected annual COS_{LN} estimates for the early tolling scenario for both a 2020 and 2025 IPP contract termination date. Likewise, Figure 11.3.4 and Table 11.3.4 shows the projected annual COS_{LN} uncertainty estimates (Std[COS_{LN}]) for these two scenarios shown in Figure 11.3.3. Under a later contract termination date, our expected COS_{LN} drops approximately 0.6 ₵/kWh, but the corresponding risk profile increases by nearly 0.3 ₵/kWh. This risk increase is directly related to the assumed loss of free CO_2 allowances after 2020; furthermore, the magnitude of this risk will be directly proportional to the corresponding uncertainty surrounding future Carbon allowance costs.

In summary, the IPP Repower Project could represent a possibly cost competitive alternative to the baseline, forward market hedging scenario, given its equivalent cost projections and nearly equivalent risk profile. The internal generation options both exhibit moderately higher cost projections and risk profiles. However, the cost and risk profiles of these options are not substantially different from either the baseline or Repower Project scenarios. The renewable energy PPA scenario represents the least cost competitive alternative studied here, although it does produce the lowest risk profile (along with the baseline, forward market hedging scenario). Additionally, the early tolling option exhibits moderately higher cost projections and/or risk profiles, at least under the 2020 IPP contract end-date scenario. More importantly, while the cost profile improves under the 2025 contract end-date scenario, the corresponding risk profile degrades significantly.

Finally, it is also critically important to realize that there are always permitting and development risks associated with the engineering, design, and construction (EDC) of new power plants. Such risks are not easily quantified in these types of asset screening studies, but are nonetheless very significant. Thus, additional studies will undoubtedly need to be performed (to account for more detailed refinements to the siting, permitting and operational characteristics associated with any of these alternative options) before we can seriously propose building or acquiring any type of internal generation asset. Likewise, additional studies will almost certainly also need to be run if there are any future policy changes in California RPS and/or GHG mandates.

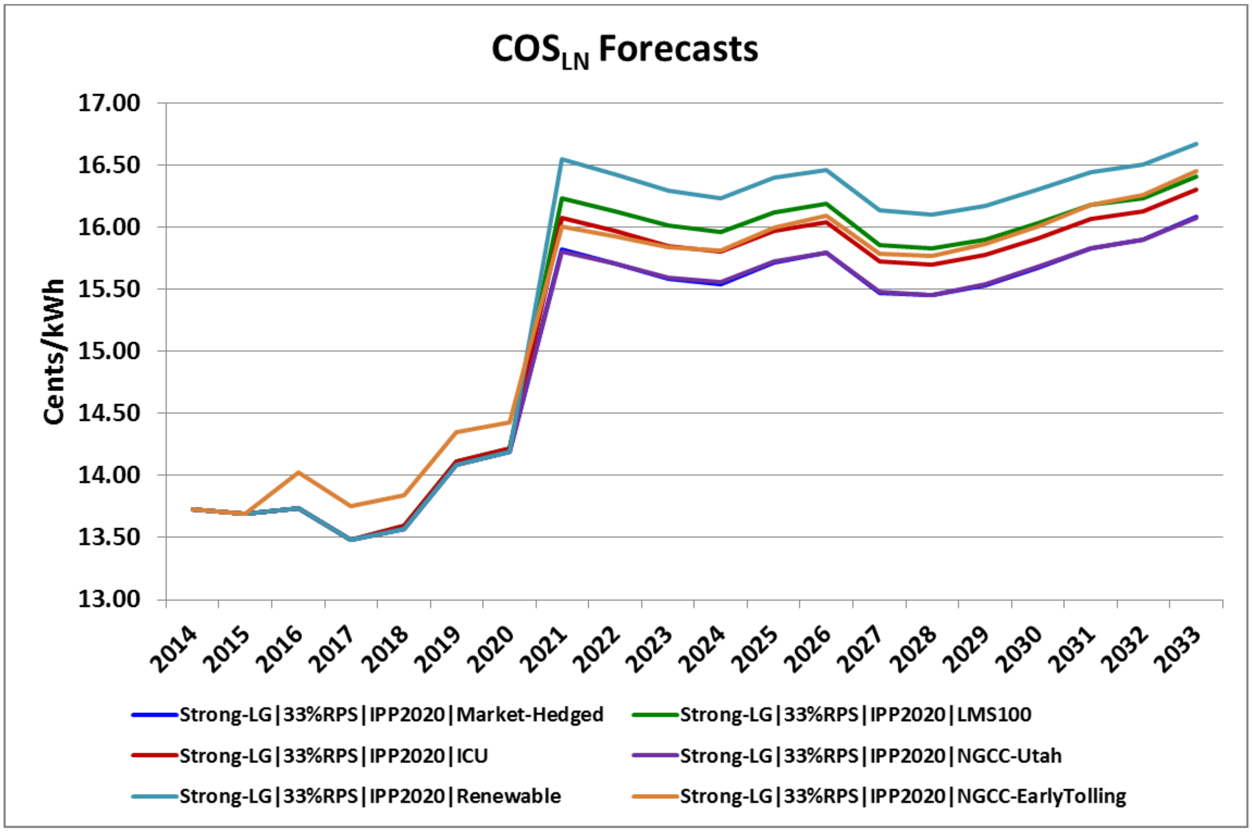


Figure 11.3.1. Projected annual COS_{LN} estimates for six IPP replacement options: (baseline and five alternatives shown in Table 11.1.1), assuming strong load growth, a 33% RPS mandate, and a 2020 IPP contract termination date.

Table 11.3.1. Figure 11.3.1 COS_{LN} estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (annual growth rates and relative cost increases). All cost units shown in ₵/kWh.

Scenario	2018	2023	2028	2033	Annual GR%
Baseline (market hedges)	13.571	15.588	15.451	16.079	1.0%
A1 (LMS 100 unit: 100 MW)	13.599	16.009	15.825	16.407	1.1%
A2 (ICE units: 46.5 MW)	13.599	15.849	15.695	16.302	1.1%
B (IPP Project: 50 MW)	13.571	15.595	15.456	16.077	1.0%
C (Renewable Project: 75 MW)	13.571	16.292	16.101	16.671	1.2%
D (2016 Tolling Contract: 150 MW)	13.839	15.837	15.764	16.451	1.1%
A1 vs Baseline	0.2%	2.7%	2.4%	2.0%	
A2 vs Baseline	0.2%	1.7%	1.6%	1.4%	
B vs Baseline	0.0%	0.0%	0.0%	0.0%	
C vs Baseline	0.0%	4.5%	4.2%	3.7%	
D vs Baseline	2.0%	1.6%	2.0%	2.3%	

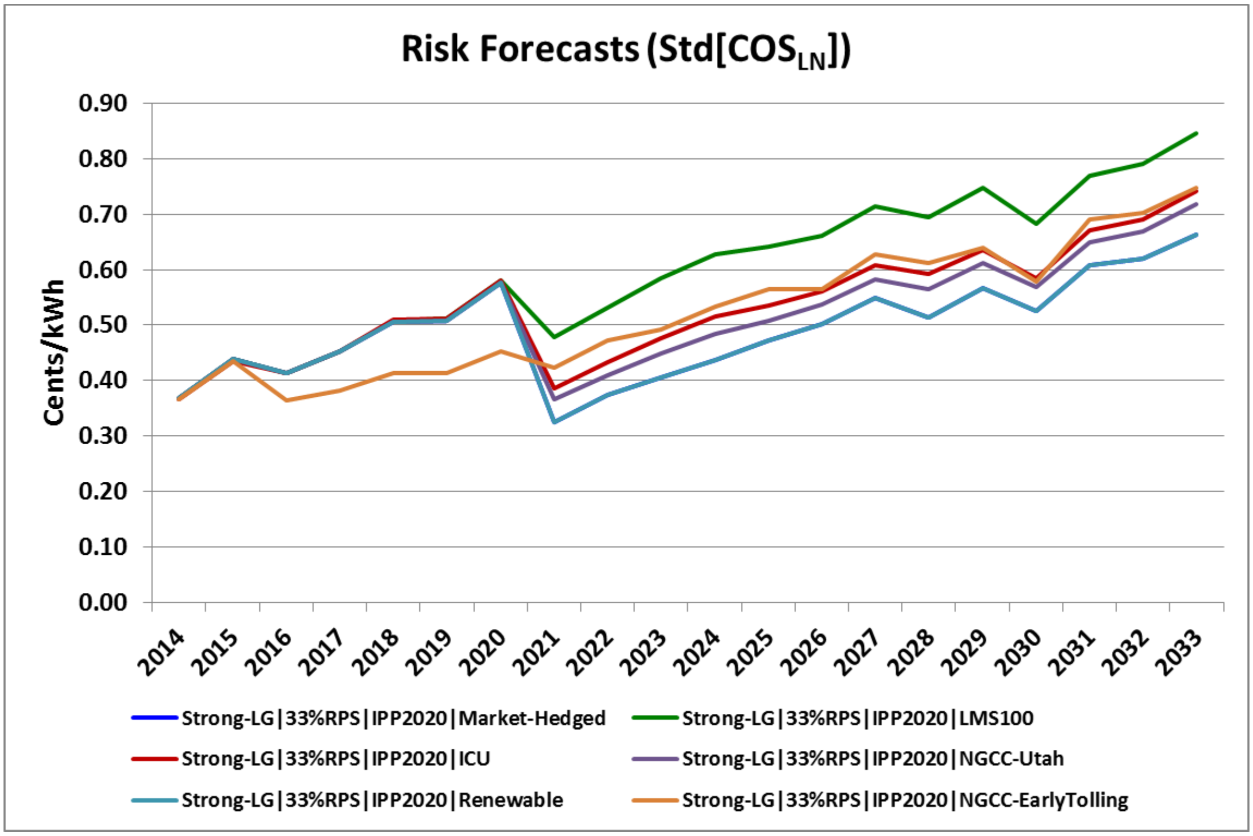


Figure 11.3.2. Corresponding annual COS_{LN} risk estimates (Std[COS_{LN}]) for the six IPP replacement options shown in Figure 11.3.1, assuming strong load growth, a 33% RPS mandate, and a 2020 IPP contract termination date.

Table 11.3.2. Figure 11.3.2 COS_{LN} risk estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (relative risk levels). All cost units shown in ₵/kWh.

Scenario	2018	2023	2028	2033
Baseline (market hedges)	0.506	0.406	0.513	0.664
A1 (LMS 100 unit: 100 MW)	0.509	0.584	0.694	0.846
A2 (ICE units: 46.5 MW)	0.509	0.477	0.591	0.741
B (IPP Project: 50 MW)	0.506	0.450	0.565	0.718
C (Renewable Project: 75 MW)	0.506	0.406	0.513	0.664
D (2016 Tolling Contract: 150 MW)	0.414	0.491	0.613	0.747
Rel Risk Baseline	3.7%	2.6%	3.3%	4.1%
Rel Risk A1	3.7%	3.6%	4.4%	5.2%
Rel Risk A2	3.7%	3.0%	3.8%	4.5%
Rel Risk B	3.7%	2.9%	3.7%	4.5%
Rel Risk C	3.7%	2.5%	3.2%	4.0%
Rel Risk D	3.0%	3.1%	3.9%	4.5%

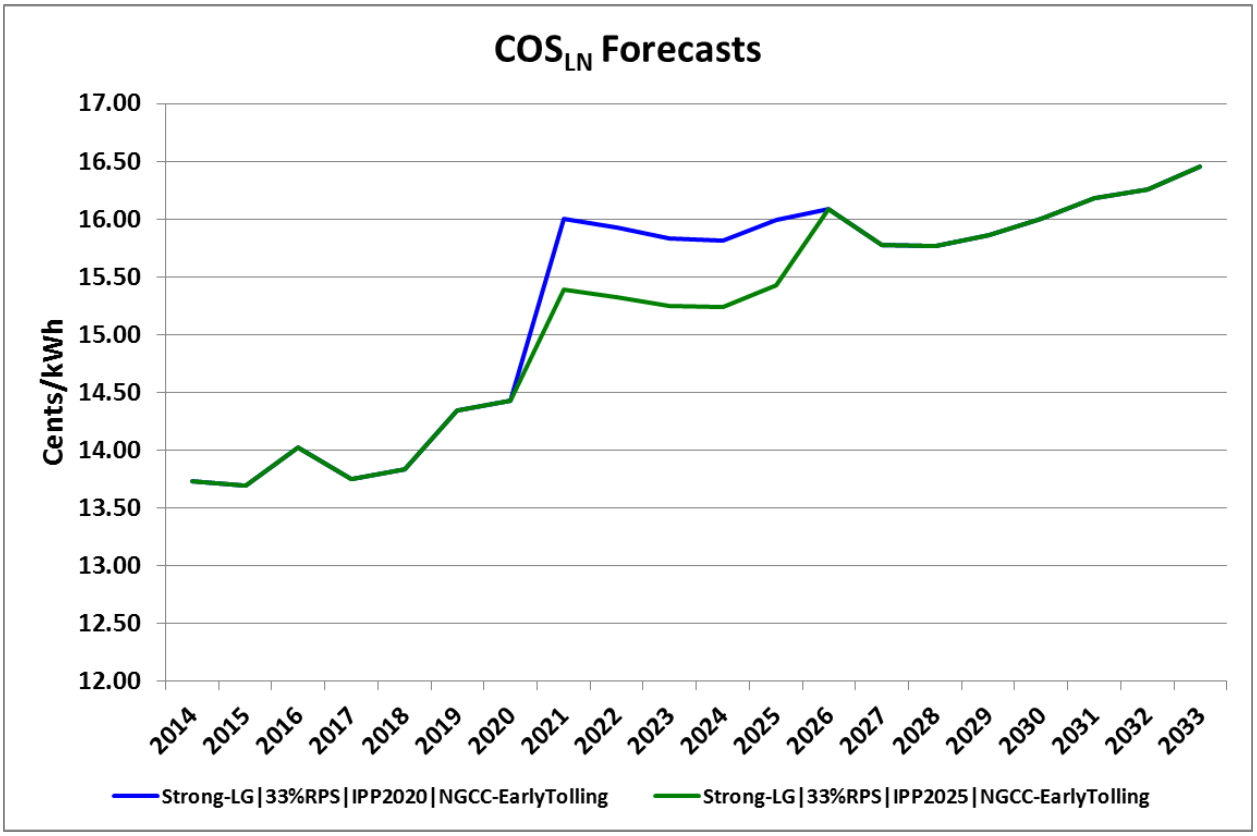


Figure 11.3.3. Projected annual COS$_{LN}$ estimates for the early tolling replacement option, under two different IPP contract end-dates (for strong load growth and a 33% RPS mandate).

Table 11.3.3. Figure 11.3.3 COS$_{LN}$ estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (annual growth rates and relative cost increases). All cost units shown in ₵/kWh.

Scenario	2018	2023	2028	2033	Annual GR%
Early Tolling Contract / Dec 2020 IPP end-date	13.839	15.837	15.764	16.451	1.1%
Early Tolling Contract / Dec 2025 IPP end-date	13.840	15.253	15.764	16.451	1.1%
2020 vs 2025	0.0%	-3.7%	0.0%	0.0%	

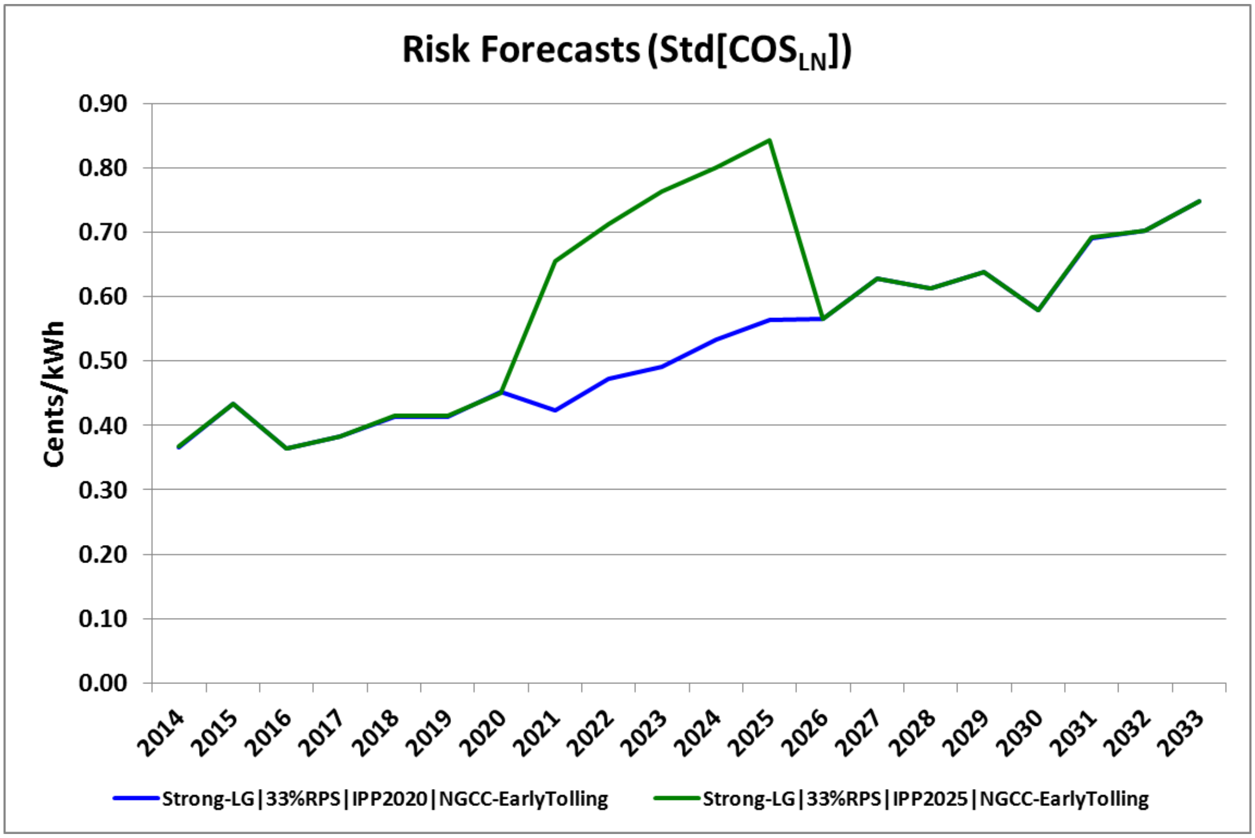


Figure 11.3.4. Corresponding annual COS$_{LN}$ risk estimates (Std[COS$_{LN}$]) for the early tolling IPP replacement options shown in Figure 11.3.3, assuming strong load growth and a 33% RPS mandate.

Table 11.3.4. Figure 11.3.4 COS$_{LN}$ risk estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (relative risk levels). All cost units shown in ₵/kWh.

Scenario	2018	2023	2028	2033
Early Tolling Contract / Dec 2020 IPP end-date	0.414	0.491	0.613	0.747
Early Tolling Contract / Dec 2025 IPP end-date	0.415	0.764	0.613	0.748
Rel Risk 2020 end-date	3.0%	3.1%	3.9%	4.5%
Rel Risk 2025 end-date	3.0%	5.0%	3.9%	4.5%

11.4 Summary and Conclusions

The results presented in this chapter are preliminary and subject to further refinements and confirmation of costs. First, with respect to building new internal generation, it is difficult to accurately estimate either the final cost of our emission offset credits, or the magnitude of our "all-other" owner capital costs; the numbers shown in Tables 11.2.2, 11.2.3, 11.2.5, and 11.2.6 are rough estimates at best. Significant changes in these cost forecasts would in turn significantly impact our projected annual debt service forecast, rendering the conclusions presented herein uncertain.

More importantly, additional secondary benefits associated with new internal generation are not quantified and analyzed here, and such benefits could be substantial in the future. For example, new internal generation could be used to improve the reliability and stability of our RPU sub-transmission system, or to maintain acceptable power levels at our CAISO point-of-interconnection if the RTRP project faces further delays. It can also serve as the foundation for RPU to consider other operational models, such as MSS load-following, and/or in itself provide value in the future for the integration of intermittent renewable resources. None of these positive and plausible benefits have been quantified and reflected in the aforementioned COS_{LN} metrics.

Similar to internal generation estimates, the EDC cost estimates associated with the Repower Project scenario are also preliminary. Although there is a general interest among at least some of the current IPP participants to pursue the Repower Project, the transformation of this concept into a successful implementation project is still rather speculative at this time (due to disagreements concerning certain contractual issues). Conceptually, given the size of the plant (~ 1000 MW), it is reasonable to assume that the capital and owner costs should be less on a $/kW basis then a much smaller internal generation option. However, even if the Repower Project proceeds Riverside will have little control over these actual costs. Should we choose to participate in this project, RPU will be dependent upon IPA to control the EDC process. It is also currently unclear if the capacity from this project will qualify as RA under the new and yet to be finalized CAISO RA paradigm, and whether or not this asset will be dynamically scheduled into the CAISO market. All of these unresolved issues have the potential to create significant, additional financial impacts on RPU. Again, these additional positive or negative impacts have not been quantified in the current analyses.

The base-load renewable option examined here is perhaps the most well defined alternative, at least with respect to mitigating potential unknown costs. However, we have yet to identify the appropriate base-load renewable resources within the CAISO footprint with the suitable profile to meet our needs at reasonable prices. Currently, geothermal, landfill gas and biomass assets appear to fit this need well. However, from a portfolio diversification perspective, RPU should probably avoid contracting for more geothermal energy (and certainly not from the Salton Sea area where RPU already has contracted for 86 MW of geothermal resources for our future needs). Hence we continue to search for competitively priced landfill gas or biomass resources that could fit our needs under this scenario, although none yet have materialized.

Given all of the above caveats, a high-level summary of our simulation results are shown in Figure 11.4. More specifically, the panel graph shown in Figure 11.4 shows the expected, load normalized cost of service (COS_{LN}) estimates in 2023, 2028 and 2033 for both the baseline and five IPP replacement scenarios examined here. These six scenarios have been ordered by their 2023 COS_{LN} estimates from high to low. In addition to each estimate (shown as black diamonds), two standard deviations of uncertainty are also shown (blue and green horizontal bars, respectively); these bars define the range of uncertainty associated with each COS_{LN} estimate. As compared to the baseline scenario, four of the five IPP replacement scenarios result in an increased cost of service, and all five replacement scenarios result in higher associated COS_{LN} uncertainty estimates. Thus, with respect to a risk minimized COS_{LN} criteria, none of the alternatives considered here outperform the baseline option of using forward hedged, market power contracts to replace our IPP contract.

Some other preliminary conclusions can also be drawn from these analyses, which are summarized below.

- The Repower Project scenario represents the most cost-effective alternative option analyzed here, although not by a wide margin. Given this result, RPU should remain engaged in the Repower Project discussions and preserve this alternative as a future option for replacing our IPP contract, assuming that these discussions continue.

- The value associated with the additional benefits that new internal generation might offer RPU need to be better understood and quantified, in order to perform a more meaningful comparison between alternatives. Additional studies will be required, given that some of these potential benefits are dependent upon the CAISO market paradigm in the future and/or the development schedule of the Riverside Transmission Reliability Project.

- It is not unreasonable to consider replacing at least some of the expiring IPP energy with base-load renewable resources if the increased cost can be justified to and accepted by RPU's customers. To implement this scenario, the key considerations will be technology and geographic diversification. In order for this alternative to be sensible, competitively priced landfill gas or biomass renewable resources in the CAISO footprint should be considered, developed, or procured under PPAs. The existing QFs that are expected to expire in the coming years with the IOUs may constitute the primary pool of resources in this category.

- The early tolling option does not appear to represent a viable alternative at this time, given the current (considerable) uncertainty surrounding the IPP contract end-date and the associated cost uncertainty for post-2020 Carbon allowances.

As discussed previously in section 11.3, the majority of these IPP replacement alternatives presented in this chapter require further refinement and study. Thus, additional follow-up studies are warranted and will be conducted in the future, as new information becomes available.

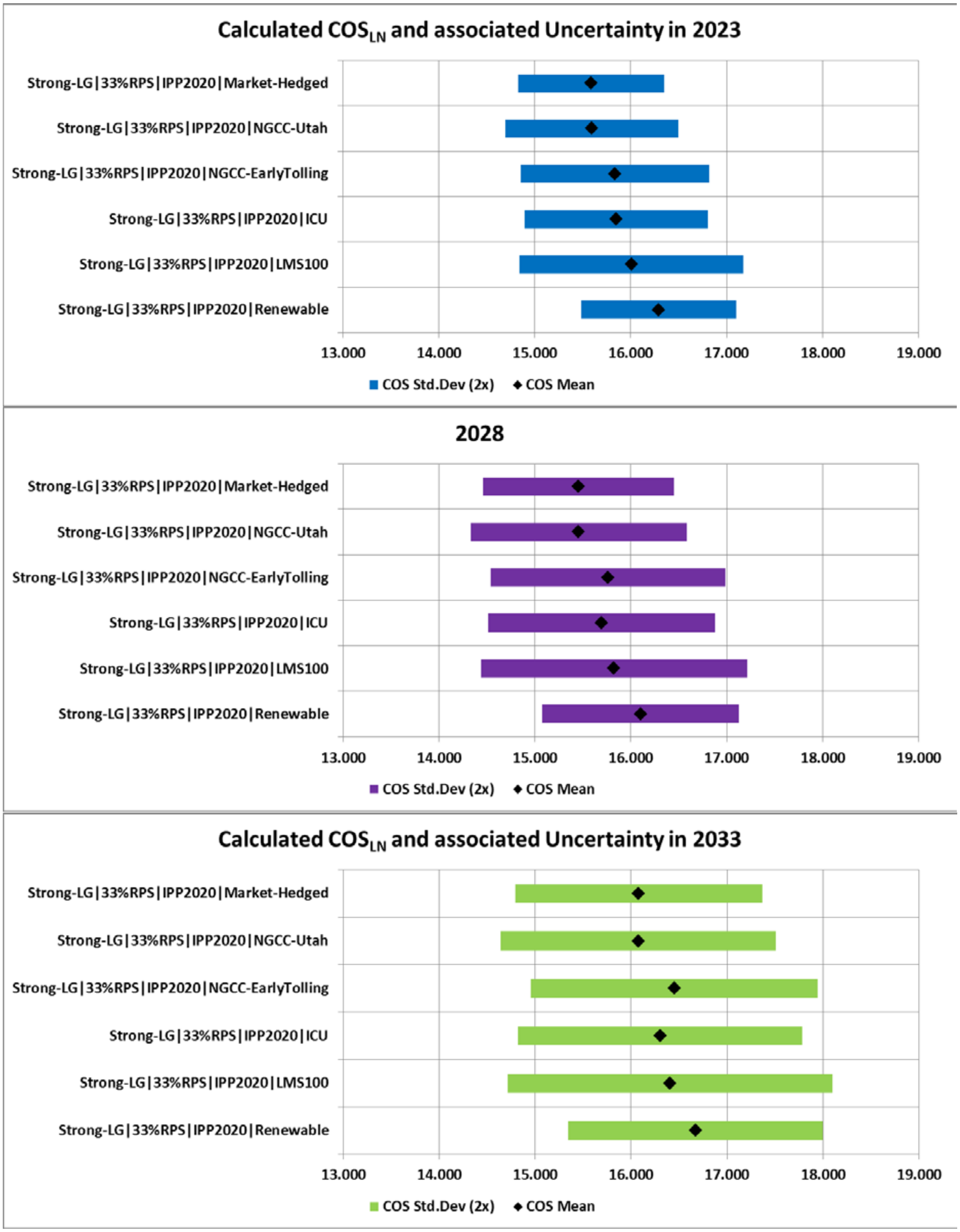


Figure 11.4. Panel plots of forecasted COS_{LN} and associated uncertainty (± 2 standard deviations) in 2023 (upper plot), 2028 (middle plot), and 2033 (lower plot), for six IPP contract replacement options.

12. Alternative Portfolio Analyses: Part II – A Higher RPS Mandate

In addition to our IPP replacement decision, RPU faces the possibility that CA may elect to increase the 33% RPS mandate after 2020. Likewise, RPU may voluntarily decide to pursue a higher internal RPS mandate, in order to reduce our carbon footprint and reliance on fossil fuel resources. Under either scenario, it is critically important to quantify the cost impacts associated with higher RPS mandates, specifically how such mandates impact our COS_{LN} metric (and associated COS_{LN} risk profile).

Recall that in Chapter 10 we examined and quantified the costs of reaching and maintaining both a 33% and 40% RPS through 2033 under our current renewable pricing assumptions. In this chapter we expand on the previous analyses by examining the projected additional portfolio cost impacts associated with RPU adopting a "50% by 2030" RPS mandate. Additionally, we also reexamine the 33%, 40% and 50% mandates under significantly higher pricing assumptions (i.e., current pricing forecasts inflated by 50%). As in Chapters 10 and 11, a 20-year forward dispatch simulation analysis is used to calculate and quantify all of our expected portfolio cost impacts, and these impacts are formally summarized via the COS_{LN} metric. Additionally, we quantify how incremental changes in both the projected price curves and RPS percentages impact this cost of service metric.

High-level Summary of Results

The panel graph shown in Figure 12.1 shows the expected, load normalized cost of service (COS_{LN}) estimates in 2028 and 2033 for the six renewable energy scenarios examined here (i.e., our 3 RPS mandates x 2 renewable energy price curves). These six scenarios have been ordered by their 2033 COS_{LN} estimates (from high to low). In addition to each estimate (shown as black diamonds), two standard deviations of uncertainty are also shown (purple and green horizontal bars, respectively); these bars define the range of uncertainty associated with each COS_{LN} estimate. It is clear from these results that the change in the renewable energy pricing assumptions has a greater impact on the cost of service estimates, as opposed to the RPS target levels. Additionally, this impact becomes more pronounced over time.

A second important result is that as the RPS target levels increase, the associated COS_{LN} uncertainty estimates decrease. (Note also that this result is independent of the underlying pricing assumptions.) Thus, higher RPS mandates can be justified with respect to a risk minimized COS_{LN} criteria, provided that the pricing of future renewable energy projects remains competitive (i.e., consistent with our current baseline price forecasts).

A more detailed discussion and summary of these results is presented in sections 12.2 and 12.3, respectively.

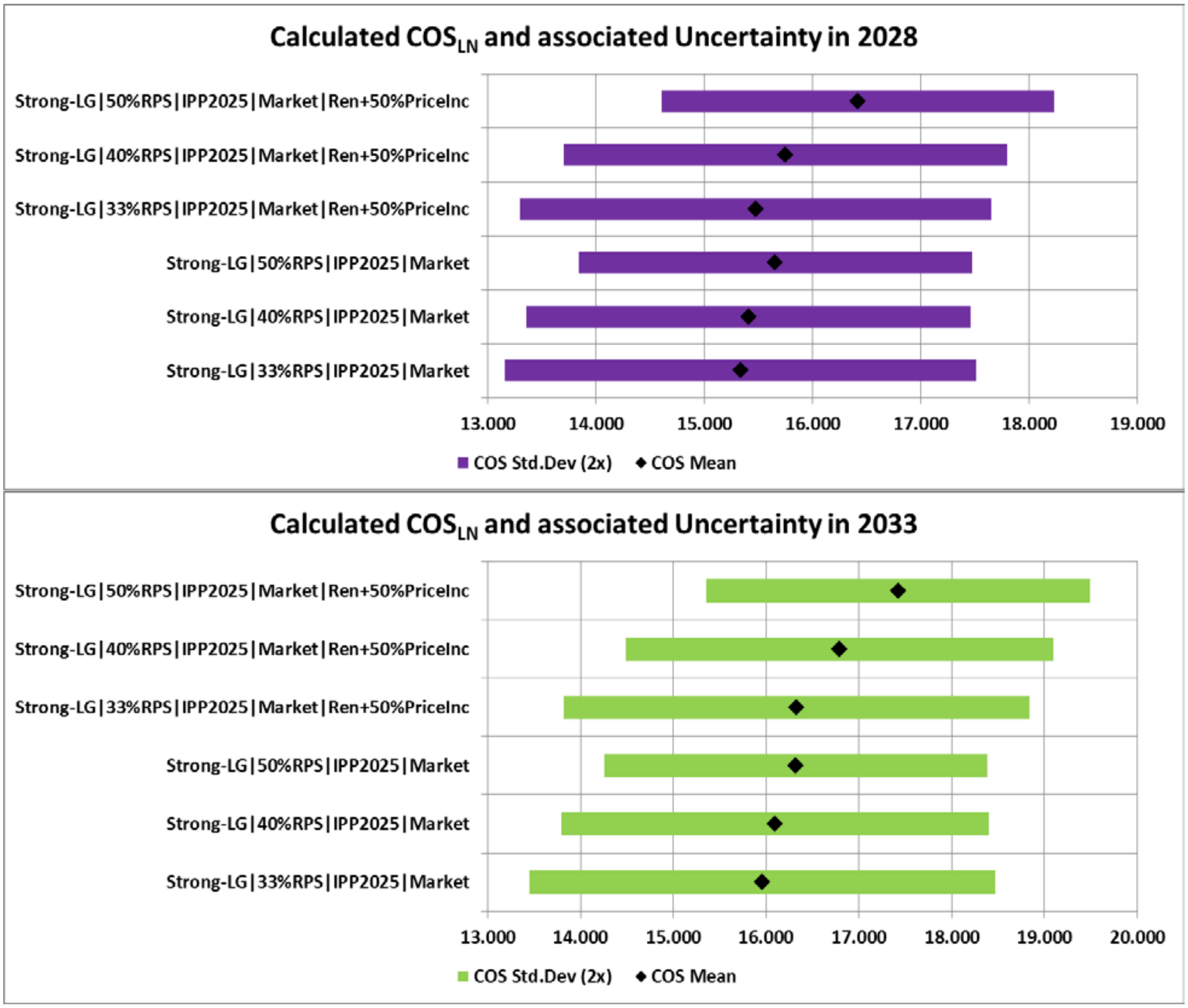


Figure 12.1. Panel plots of forecasted COS_{LN} and associated uncertainty (± 2 standard deviations) in 2028 (upper plot) and 2033 (lower plot), for six future renewable energy scenarios.

12.1 RPS Inputs and Assumptions

As discussed in Chapter 9, Riverside will need to procure additional renewable energy resources in the latter part of the 2014-2033 time horizon to remain fully RPS compliant. In section 9.2, we also defined two alternative, higher-RPS scenarios: the 40% by 2030 and 50% by 2030 scenarios shown in Table 9.2.1. Additionally, we specified a series of generic renewable capacity expansion plans for each RPS and load growth scenario, as discussed in Tables 9.2.2 and 9.2.3 and shown in Figures 9.2.1 through 9.2.5, respectively. However, recall that in Chapter 10 we only analyzed and contrasted the less aggressive 40% by 2030 RPS scenario with our baseline scenario (i.e., our current 33% RPS mandate).

In this chapter we examine the projected additional portfolio cost impacts associated with RPU adopting a 50% by 2030 RPS mandate, and compare and contrast this with our previously analyzed 40%

by 2030 and 33% baseline scenarios. Additionally, we reanalyze all three scenarios under alternative renewable energy pricing schemes that are 50% higher than our pricing assumptions used in Chapter 10. Our specific renewable energy pricing assumptions are shown in Table 12.1.1 below.

Table 12.1.1. Renewable energy pricing assumptions (2024-2033) for our generic renewable energy assets.

Year	Current (Baseline) Price Curves			High Price Curves (50% Price Increase)		
	Wind	Solar PV	Geothermal	Wind	Solar PV	Geothermal
2024	$69.63	$77.72	$82.06	$104.45	$116.59	$123.10
2025	$70.68	$78.89	$83.30	$106.02	$118.34	$124.94
2026	$71.74	$80.07	$84.54	$107.61	$120.11	$126.82
2027	$72.81	$81.27	$85.81	$109.22	$121.91	$128.72
2028	$73.91	$82.49	$87.10	$110.86	$123.74	$130.65
2029	$75.01	$83.73	$88.41	$112.52	$125.60	$132.61
2030	$76.14	$84.99	$89.73	$114.21	$127.48	$134.60
2031	$77.28	$86.26	$91.08	$115.92	$129.39	$136.62
2032	$78.44	$87.56	$92.44	$117.66	$131.33	$138.67
2033	$79.62	$88.87	$93.83	$119.43	$133.30	$140.75

It should be noted that the analyses presented here do not address the technical feasibility issues concerning the ability of the CAISO grid to support higher RPS mandates. Instead, we focus solely on our own renewable procurement costs (as specified in Table 12.1.1 above), and how these costs combine with the RPS portfolios described previously in Tables 9.2.2 and 9.2.3 to impact our COS_{LN} metric. As noted previously in Chapter 9, Riverside would need to procure a significant amount of additional renewable resources in the latter part of the 2014-2033 timeframe, in order to reach full RPS compliance under the 50% by 2030 mandate.

The following additional assumptions are incorporated into all six renewable energy scenarios: (a) strong load growth, (b) a 2025 IPP contract end date, and (c) unhedged market purchases after 2025 (to replace our lost IPP energy). Note that we restrict our analyses to the strong load growth scenario, since this scenario requires RPU to make significantly more investments in renewable energy assets. Likewise, since very few new renewable energy assets need to come on-line before 2025 (see Table 9.2.2), it is sufficient to analyze these studies for only the 2025 IPP contract end date assumption. Finally, although in practice we would not replace our lost IPP energy with unhedged market energy purchases, in the following analyses such an assumption allows us to more accurately quantify the impacts of higher RPS levels on the associated COS_{LN} risk profiles.

Finally, the same simulation methodology described in chapters 10 and 11 has been used to (re)assess these various RPS scenarios. More specifically, one hundred (100) new simulation runs have been performed for each RPS and pricing option scenario, in order to quantify both the expected annual load serving costs and the associated uncertainty (i.e., standard deviation) surrounding these cost estimates. These new simulation runs have again been performed at an hourly granularity over the same twenty year timeframe (January 1, 2014 through December 31, 2033), using the same set of input forward price curves. As in Chapters 10 and 11, COS_{LN} value and risk estimates are used to facilitate all comparisons between the 33%, 40% and 50% options. Lastly, all of the additional, fixed costs discussed in sections 10.2.1 through 10.2.8 have also been applied to this alternative scenario, in order to facilitate a consistent set of comparisons.

12.2 33% Baseline, 40% by 2030 and 50% by 2030 RPS Mandates: Impacts on RPU's COS_{LN}

Figure 12.2.1 shows our projected annual COS_{LN} estimates (shown in ₵/kWh units) for the three RPS scenarios that define the 33% versus 40% versus 50% RPS mandates under the baseline energy pricing assumptions. Note that our IPP contract is assumed to run through 2025 in each of these three scenarios, and unhedged, SP15 market power is used to fill this energy void upon contract termination. Additionally, Table 12.2.1 shows the corresponding COS_{LN} estimates for years 2018, 2023, 2028 and 2033, respectively, and summarizes the relevant scenario comparisons. More specifically, the annual COS_{LN} growth rate for each scenario is shown in the last column, and the bottom three rows quantify pertinent % cost increases for the 40% versus 33%, 50% versus 33%, and 50% versus 40% RPS scenarios, respectively.

As shown in Figure 12.2.1., higher RPS mandates raise our expected COS_{LN}, but the absolute magnitude increase is relatively minimal. As shown previously in section 10.3, "Scenario B vs A" quantifies the impacts on our expected cost of service if we adopt a 40% RPS mandate under current renewable energy pricing expectations – this cost increase is forecasted to be less than 1%. "Scenario C vs A" quantifies the 50% versus 33% cost increase; note that this is forecasted to be ≤ 2.3% through 2033. Additionally, note that the annual COS_{LN} growth rate is forecasted to remain around 1.0% under all three RPS scenarios.

The other important features shown in Figure 12.2.1 are the abrupt cost increases that occur in 2021 and 2026. The 0.6 ₵/kWh to 0.7 ₵/kWh cost of service increase in 2026 is due to the termination of our IPP contract (on January 1, 2026). In contrast, the 1.0 ₵/kWh cost increase in 2021 is a direct result of the end of free Carbon allowances; i.e., this is the cost increase that RPU should expect to absorb if no further emission compliance instruments are freely allocated after 2020. (Both of these effects were noted previously in section 10.3.)

Figure 12.2.2 shows the projected annual COS_{LN} uncertainty estimates (Std[COS_{LN}]), shown in ₵/kWh units) for the three corresponding RPS scenarios shown in Figure 12.2.1. Table 12.2.2 provides the associated COS_{LN} risk estimates for years 2018, 2023, 2028 and 2033, respectively. Note that under all three scenarios, our portfolio risk more than doubles on/after 2026. This effect is a direct result of the loss of free carbon allowances after 2020 and the replacement of our fixed price IPP contract with open, unhedged SP15 market energy purchases, the latter being subject to significant price uncertainty. (These issues are discussed in detail in section 10.6.) However, it is also worth noting that the 50% RPS plan produces a Std[COS_{LN}] estimate of 1.03₵/kWh in 2033, which is about 0.22₵/kWh lower than the 33% RPS plan. This risk reduction is directly due to the increased volume of fixed price, renewable PPAs in the 50% portfolio. Hence, the higher 2033 cost of service forecast under the 50% versus 33% RPS plans (16.32₵/kWh versus 15.96₵/kWh) is at least in part offset by this lower risk profile.

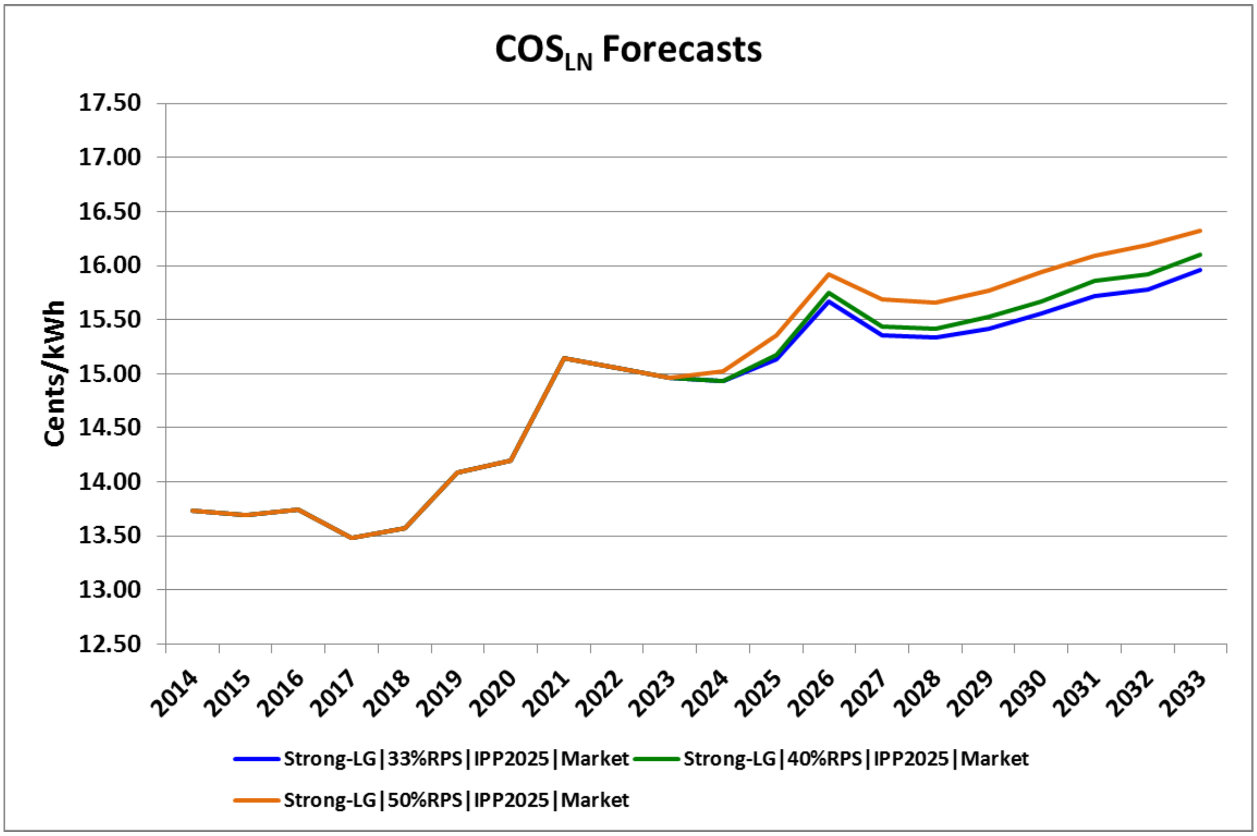


Figure 12.2.1. Projected annual COS_{LN} estimates for three RPS mandates (33%, 40%, and 50%) under the baseline renewable energy pricing assumptions.

Table 12.2.1. Figure 12.2.1 COS_{LN} estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (annual growth rates and relative cost increases). All cost units shown in ₵/kWh.

Scenario	2018	2023	2028	2033	AGR%
A. Strong-LG|33%RPS|IPP2025|Market	13.572	14.961	15.336	15.962	1.0%
B. Strong-LG|40%RPS|IPP2025|Market	13.572	14.961	15.411	16.100	1.0%
C. Strong-LG|50%RPS|IPP2025|Market	13.572	14.961	15.659	16.324	1.1%
Scenario B vs A	0.0%	0.0%	0.5%	0.9%	
Scenario C vs A	0.0%	0.0%	2.1%	2.3%	
Scenario C vs B	0.0%	0.0%	1.6%	1.4%	

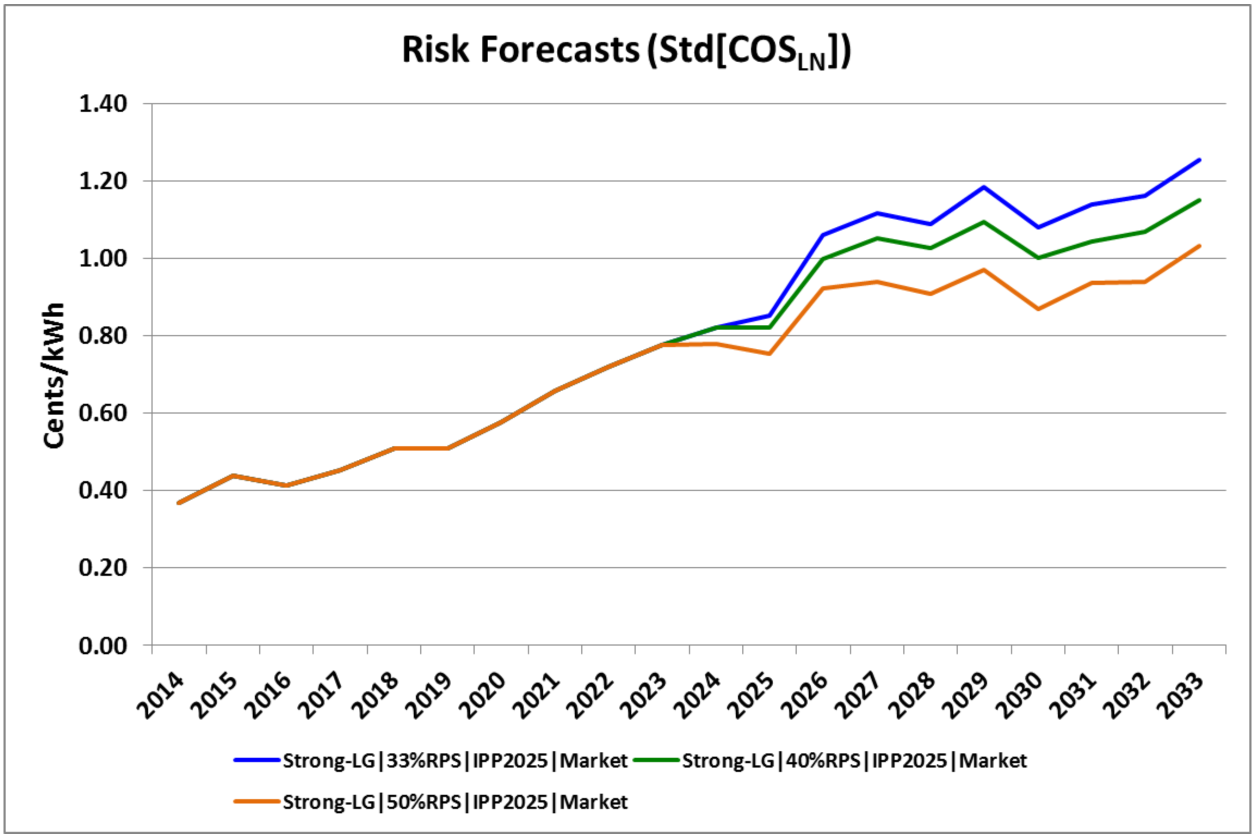


Figure 12.2.2. Corresponding annual COS_{LN} risk estimates (Std[COS_{LN}]) for the three RPS scenarios (33%, 40%, and 50%) shown in Figure 12.2.1.

Table 12.2.2. Figure 12.2.2 COS_{LN} risk estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (relative risk levels). All cost units shown in ₵/kWh.

Scenario	**2018**	**2023**	**2028**	**2033**
A. Strong-LG|33%RPS|IPP2025|Market	0.507	0.777	1.088	1.255
B. Strong-LG|40%RPS|IPP2025|Market	0.507	0.777	1.026	1.151
C. Strong-LG|50%RPS|IPP2025|Market	0.507	0.777	0.909	1.032
Relative Risk of Scenario A	3.7%	5.2%	7.1%	7.9%
Relative Risk of Scenario B	3.7%	5.2%	6.7%	7.2%
Relative Risk of Scenario C	3.7%	5.2%	5.8%	6.3%

Figure 12.2.3 shows our projected annual COS_{LN} estimates for the same three RPS scenarios that define the 33% versus 40% versus 50% RPS mandates under the strong load growth assumption, but now for the elevated renewable energy pricing assumptions. As before, unhedged SP15 market power is used to fill this energy void upon contract termination. Additionally, Table 12.2.3 shows the corresponding COS_{LN} estimates for years 2018, 2023, 2028 and 2033, respectively, and again summarizes some relevant scenario comparisons. (The annual COS_{LN} growth rate for each scenario is shown in the last column, and the bottom four rows quantify pertinent % cost increases for specific scenario comparisons.)

As before, higher RPS mandates raise our expected COS_{LN}, but now the absolute magnitude increase is much more significant. The 40% cost increase is forecasted to now be around 3% and the 50% cost increase is forecasted to be just under 7% through 2033. The other patterns in the cost of service forecasts are the same as before; i.e., the abrupt cost increases that occur in 2021 and 2026. Again, the 0.6 ₵/kWh to 0.7 ₵/kWh cost of service increase in 2026 is due to the termination of our IPP contract (on January 1, 2026). Likewise, the 1.0 ₵/kWh cost increase in 2021 is a direct result of the end of free carbon allowances.

Figure 12.2.4 shows the projected annual COS_{LN} uncertainty estimates (Std[COS_{LN}]) for the three RPS scenarios shown in Figure 12.2.3. Table 12.2.4 provides the associated COS_{LN} risk estimates for years 2018, 2023, 2028 and 2033, respectively. Note that the data shown in Table 12.2.4 is identical to the data shown in Table 12.2.2, because the associated risk calculations are unaffected by the renewable energy pricing assumptions. Thus, once again, our portfolio risk more than doubles on/after 2026. Likewise, the 50% RPS plan produces a Std[COS_{LN}] estimate of 1.03₵/kWh in 2033, which is about 0.22₵/kWh lower than the 33% RPS plan. However, the higher 2033 cost of service forecasts under these revised pricing scenarios (17.43₵/kWh versus 16.33₵/kWh) greatly outweigh the nominal risk reduction associated with the lower risk profile.

The magnitude of the simulated 2033 cost impacts are shown graphically in Figure 12.2.5 using the 33% RPS scenario (with our current renewable energy price curves) as the baseline. It is clear that the future cost of service in these analyses is primarily determined by the renewable energy pricing assumptions. For example, under a 50% RPS mandate, we can expect the COS_{LN} to increase by 0.22₵/kWh for every 10% price increase above our baseline renewable energy pricing assumptions. Under a 40% RPS mandate, we can expect the COS_{LN} to increase by 0.14₵/kWh for every 10% price increase above our baseline pricing assumptions.

Overall, these results suggest that our total energy related portfolio costs will be rather sensitive to our renewable energy PPA costs, should RPU unilaterally adopt either a "40% by 2030" or "50% by 2030" RPS mandate. Thus, if higher RPS mandates are going to be seriously considered by RPU, we may wish to secure some of these energy contracts now, in order to take advantage of the currently low renewable energy prices. It is also critically important to emphasize here that these analyses <u>do not consider or incorporate</u> the additional uplift or variable energy integration costs that are currently being proposed for the CAISO market. At present, these additional costs are very difficult to estimate, but are expected to be potentially significant.

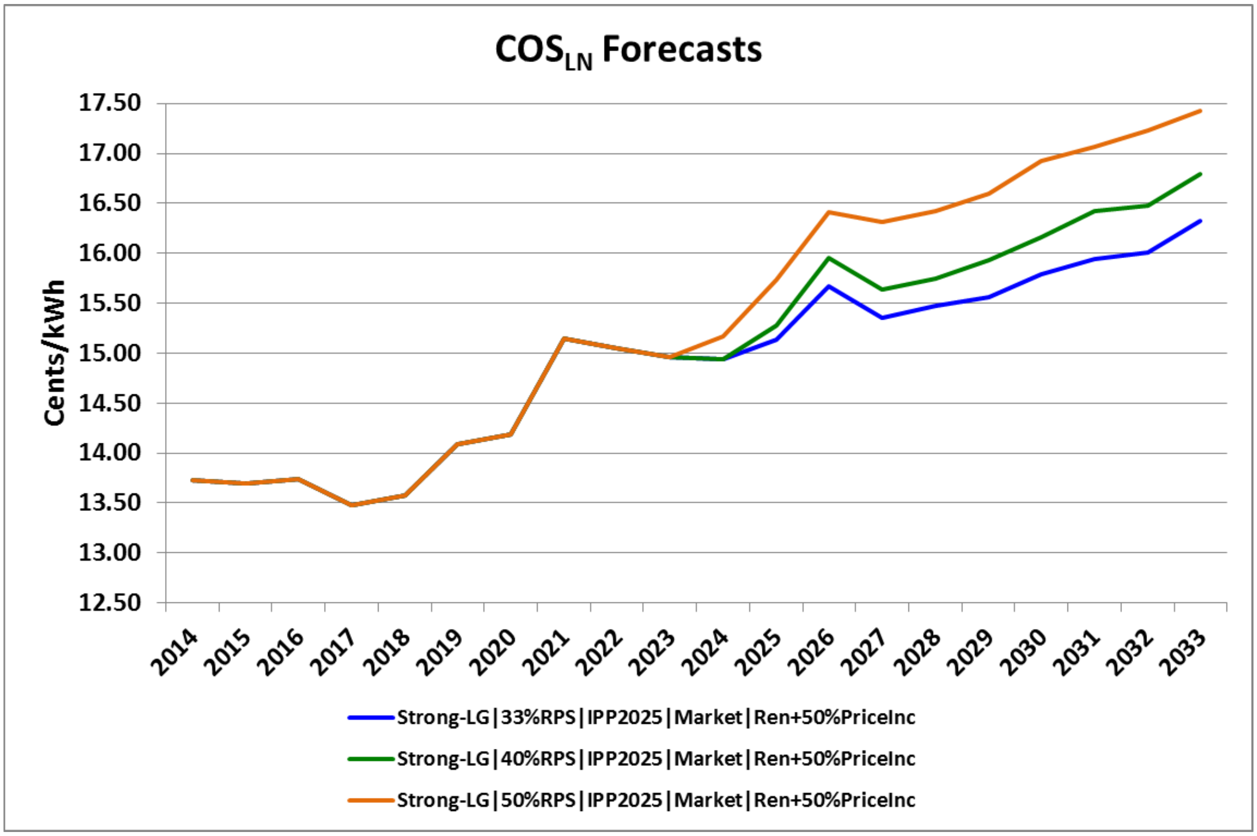


Figure 12.2.3. Projected annual COS$_{LN}$ estimates for three RPS mandates (33%, 40%, and 50%) under the elevated renewable energy pricing assumptions.

Table 12.2.3. Figure 12.2.3 COS$_{LN}$ estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (annual growth rates and relative cost increases). All cost units shown in ₵/kWh.

Scenario	**2018**	**2023**	**2028**	**2033**	**AGR%**
A. Strong-LG|33%RPS|IPP2025|Market|50%PI	13.572	14.961	15.477	16.327	1.1%
B. Strong-LG|40%RPS|IPP2025|Market|50%PI	13.572	14.961	15.749	16.792	1.3%
C. Strong-LG|50%RPS|IPP2025|Market|50%PI	13.572	14.961	16.420	17.425	1.5%
Scenario B vs A	0.0%	0.0%	1.8%	2.9%	
Scenario C vs A	0.0%	0.0%	6.1%	6.7%	
Scenario C vs B	0.0%	0.0%	4.3%	3.8%	

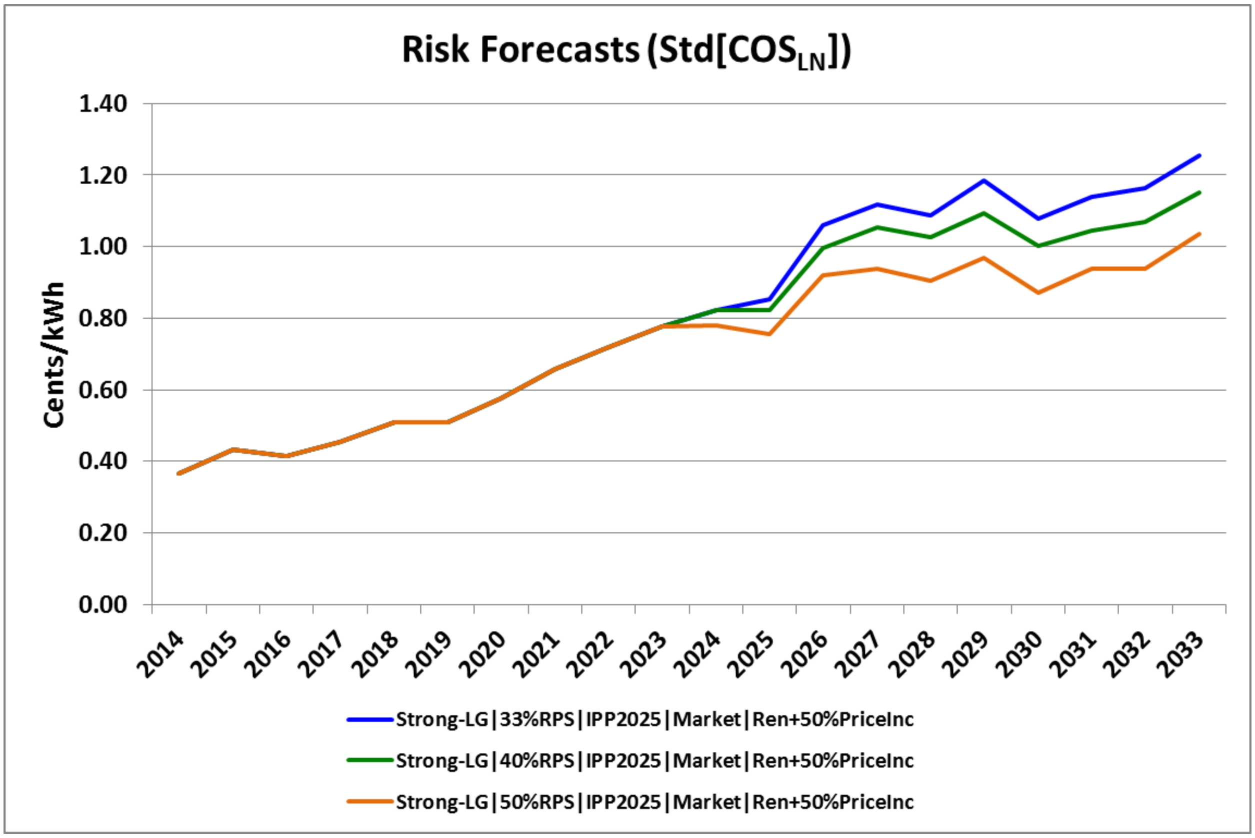
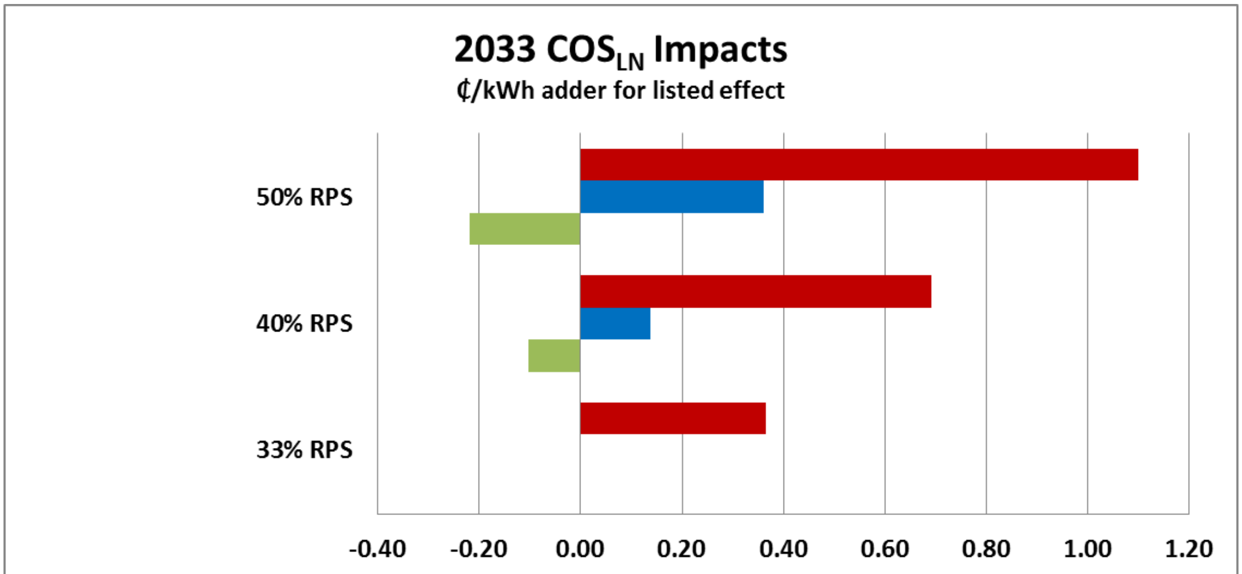


Figure 12.2.4. Corresponding annual COS$_{LN}$ risk estimates (Std[COS$_{LN}$]) for the three RPS scenarios (33%, 40%, and 50%) shown in Figure 12.2.3.

Table 12.2.4. Figure 12.2.4 COS$_{LN}$ risk estimates for years 2018, 2023, 2028 and 2033, along with relevant scenario comparisons (relative risk levels). All cost units shown in ¢/kWh.

Scenario	2018	2023	2028	2033
A. Strong-LG|33%RPS|IPP2025|Market|50%PI	0.507	0.777	1.088	1.255
B. Strong-LG|40%RPS|IPP2025|Market|50%PI	0.507	0.777	1.025	1.152
C. Strong-LG|50%RPS|IPP2025|Market|50%PI	0.507	0.777	0.906	1.035
Relative Risk of Scenario A	3.7%	5.2%	7.0%	7.7%
Relative Risk of Scenario B	3.7%	5.2%	6.5%	6.9%
Relative Risk of Scenario C	3.7%	5.2%	5.5%	5.9%



	33% RPS	40% RPS	50% RPS
50% Price Increase (¢/kWh)	0.37	0.69	1.10
RPS Mandate (¢/kWh)	0.00	0.14	0.36
Risk Reduction (¢/kWh)	0.00	-0.10	-0.22

Figure 12.2.5. Projected annual net COS$_{LN}$ impacts in 2033 for the three RPS mandates under the baseline and elevated renewable energy pricing assumptions.

12.3 Summary and Conclusions

The results presented in this chapter define a range of potential future rate impacts for different RPS mandates and renewable energy pricing assumptions. Figure 12.2.5 quantifies and summarizes how these various net rate impacts relate to our assumed RPS mandates and corresponding energy price curves, respectively. Likewise, Figure 12.1 shows panel plots of our forecasted COS_{LN} and associated uncertainty (± 2 standard deviations) in 2028 and 2033, for the six renewable energy scenarios examined here.

As discussed previously in Chapter 10, RPU is currently on track to reach a 37% RPS level by 2019 (and stay above the 33% RPS mandate at least through 2023), after accounting for the renewable energy PPAs that we have already contracted for. Hence, achieving the “40% by 2030” mandate is well within our reach, provide that our current contracts come to fruition and are strategically supplemented with cost-competitive future renewable energy resources. Under the current renewable energy pricing scenarios, the rate impact of such a strategy should be minimal – provided that the CAISO does not impose significant secondary renewable energy integration costs on the load serving entities within its balancing authority area.

This latter point is worth elaborating on. Currently, there are a number of CAISO sponsored initiatives and stake-holder processes directed (either in whole or in part) towards optimally integrating variable (renewable) energy resources into the California grid. The Flexible Resource Adequacy and Enhanced Must Offer Obligation (FRAC/MOO), Energy Imbalance Market (EIM), and Joint Reliability Framework (JRF) initiatives are all designed to address the integration of variable energy resources (see section 5.2). Once implemented, each of these new paradigms may impose significant new costs to CAISO load serving entities. As such, the costs associated with reaching and maintaining higher RPS mandates may be significantly higher than our baseline projections.

Parallel with these efforts, the CPUC has recently mandated the IOUs to begin procuring significant amounts of transmission, distribution, and behind-the-meter energy storage options, again primarily to facilitate integrating greater amounts of renewable energy into the grid. Currently, AB 2514 (see section 5.1.5) does not mandate the POUs to procure equivalent amounts of energy storage options, but realistically this could change in the near future, via a legislative fiat. Such new energy storage mandates will only further serve to raise our cost of service, if/when they are imposed on POUs.

Finally, it has become abundantly clear that the State of California is very serious about achieving and systematically increasing statewide reductions in GHG emissions. Realistically, it is only a matter of time before the state legislature revisits the 33% RPS mandate and imposes new and more stringent, post-2020 renewable energy targets. It should also be emphasized that the forecasted baseline renewable energy prices represent current market prices under the existing 33% RPS mandate. Should the state-wide, post-2020 RPS mandate increase , one would naturally expect that market renewable prices to also increase, thus resulting in increased energy cost impacts to RPU’s portfolio (i.e., higher than the baseline cost forecasts presented here).

Taken together, all of these issues suggest that RPU would be wise to continue increasing the number of renewable energy assets in its portfolio, but also to do so in a very thoughtful and strategic manner. For example, given the numerous problems (and potential costs) associated with integrating variable energy resources into the grid, a preference towards acquiring either base-load or dispatchable renewable resources would seem to be justified. In contrast, contracting for a significant amount of additional solar PV resources is probably unwise right now, given the increasing uncertainty about how the net-load “duck-curve” effect might impact the CAISO market (see section 5.2.3). Instead, contracting for a seasonally-structured energy product where a third party “firms-up” the delivery amount of a variable energy resource could be highly advantageous, and should at least be considered. Finally, it seems logical that RPU should pursue future contracts for renewable energy assets that incorporate (or retain the option to incorporate) energy storage technology. Ideally, such contracts would give us the optionality to develop some form of energy storage option at a later date (e.g., after the costs associated with the storage technology have hopefully decreased).

In summary, RPU should be very strategic about how it continues to work toward acquiring and incorporating a greater percentage of renewable energy assets into its resource portfolio. Although some of the cost pressures discussed above may turn out to be unavoidable, others can hopefully be minimized via the diligent application of intelligent planning activities and reasonable foresight.

13. Important Secondary Resource Planning Issues

In addition to our IPP replacement and RPS target decisions, RPU faces a number of additional longer-term resource planning issues that deserve additional attention. In this chapter we examine four of these resource planning issues in greater detail. More specifically, in this chapter we will examine the value of a "generic" Energy Storage system, the value of an "ideal" DSM/DR program, the cost/benefit impacts associated with customer installed solar PV systems in the RPU service area, and the potential benefits and impacts associated with electric vehicles. The first three of these topics represent pressing current issues for RPU, and all four topics are described in more detail below.

13.1 Specific Issues and Topics

13.1.1 Energy Storage

In section 13.2, we examine the potential financial benefits of generic energy storage systems in the RPU service territory. We first specify a hypothetical, generic energy storage (ES) system with a pre-determined charging and discharging interval in our production cost modeling environment, and then dispatch this system under a full set of market simulations. The implied revenue stream of this generic ES system is then computed by combining the appropriately calculated peak versus off-peak energy revenue streams with the avoided RA costs. These results are then further extended to also produce approximate value estimates for a dynamic system, by making some very high level simplifying assumptions concerning the expected value of the ancillary service revenue stream. The final product from this analysis is a set of $/kW value curves for generic ES systems with different useful life expectancies and energy charge-to-discharge efficiency factors.

13.1.2 An Ideal DSM/DR Program

In section 13.3 we examine the potential value for an "ideal" Demand Side Management / Demand Response program that would reduce our summer peak energy needs by 5%, but without reducing our volumetric energy sales. In theory, such a program could be used to "smooth out" and reduce our projected 1-in-2 summer peaking needs, without impacting our retail revenue stream. After quantifying our peak reduction input assumptions, a twenty-year forward dispatch simulation analysis is used to calculate and quantify our expected system load and RA cost savings. As with the ES system study, the final product from this analysis is a set of annual $/kW value estimates for this ideal DSM/DR program.

13.1.3 Customer Solar PV

In section 13.4, we examine some of the current and forecasted financial impacts to RPU resulting from the installation of customer owned solar PV systems in our service territory. More specifically, this analysis attempts to quantify the partial unmet revenue effect associated with net energy metering (NEM) contracts, using the same criteria discussed in section 6.5 and 6.6. The goal of this analysis is to determine the partial net program impact ($/kW basis), based on the difference between our unmet retail revenues and our avoided power supply and capacity expansion costs, and then forecast this impact ten years into the future (assuming that current customer solar PV installation rates stabilize at 2 MW of capacity per year after 2016).

13.1.4 Electric Vehicles

In 2012, California Governor Jerry Brown set a state target of getting 1.5 million zero-emission vehicles on California roads by 2025. This aggressive goal is being pursued by California due to the potential for EVs to dramatically reshape the way in which electricity is stored, managed and regulated on the electrical grid. In section 13.5 we examine the projected impacts and potential benefits of significant electric vehicle penetration to the California grid, and briefly discuss the impacts to date in the RPU service territory.

13.2 Value Analysis: 10 MW of Energy Storage

There are currently multiple types of energy storage options in various stages of research and/or commercial development. Historically, RPU has implemented some customer side thermal energy storage options, primarily encouraged through incentivized rebates. However, a number of other technologies have recently emerged that offer the potential to be dynamically scheduled and dispatched into the CAISO markets (e.g., various types of battery storage, compressed air storage, smart-grid driven DR technology, etc.). Unfortunately, most of these newer technologies are relatively unproven, and Riverside does not yet have sufficient, publically available performance information to undertake any type of detailed production cost modeling assessment of their cost effectiveness. (Industry standard pricing information is available; see section 13.2.4 for details.)

Given the unique and technology specific characteristics of different energy storage options, it is challenging to develop a "one-size fits all" analysis of the value of such options. However, a bench-mark reference point (or set of reference points) is still both useful and desirable, particularly when a refined analysis on a specific technology cannot yet be performed. Thus, as an alternative to assessing one or more unique (and still evolving) technologies, we have produced a high-level assessment of a "generic energy storage" option, subject to some general simplifying assumptions concerning the generic ES characteristics. The characteristics that must be *a priori* defined are as follows:

(1) when and how the ES asset charges and discharges,
(2) assuming the asset discharges energy during peak load periods, what type of avoided RA costs can we expect benefit from; i.e., avoided system, local, or blended RA costs,
(3) will the asset charge and discharge in a pre-determined (passive) manner, or can it be dynamically charged and discharged in response to prevailing market price signals, and
(4) if it is a dynamic system, what monetary value for ancillary services can it expect to receive.

Subject to certain simplifying assumptions concerning these characteristics, one can then forecast out a ten- or twenty-year revenue stream, compute the net present value (NPV) of this revenue stream, and determine a 1st-order estimate of the value of the generic ES option on a $ per installed kW of capacity basis.

13.2.1 Generic Energy Storage Characteristics and Input Assumptions

In the following analysis, we have chosen to model a generic passive ES system in our production cost modeling environment for pre-determined charging and discharging intervals. The implied revenue stream of this generic ES system can then be determined by combining the appropriately calculated peak versus off-peak energy revenue stream with the avoided RA costs. We've then extended these results to also produce approximate value estimates for a dynamic system, by making some very high level simplifying assumptions concerning the expected value of the ancillary service revenue stream. More specific details concerning these various calculations are presented in the next section.

13.2.2 NPV Calculations for a Generic Energy Storage Option

The approach taken in this analysis is rather general in nature, and designed to elicit a set of bench-mark reference points. Specifically, we will determine the approximate value of generic energy storage on a $/kW installed basis, subject to the set of input assumptions and modeling strategies outlined below:

1. In the PowerSimm environment, we first specified a generic ES "resource" that would charge (or use) 10 MW of energy per hour for 6 hours a day, 7 days a week during hours HE01-HE06. This same resource would then discharge F_E x 10 MW per hour for 6 hours a day, 7 days a week during hours HE17-HE22 (November – April) or HE14-HE19 (May- October), where $0.5 < F_E < 1$ represents a technology specific "efficiency factor". Intuitively, this latter factor defines the amount of energy that the generic ES resource can return to the market; i.e., $F_E = 0.7$ implies that the resource can return 7 MW per hour for every 10 MW per hour that it extracts. Note also that the discharge intervals were chosen to provide the highest potential energy sales value (on average), while aligning with our monthly system peaks.
2. This generic ES resource was then dispatched each day to the forward SP15 market (20 years forward), and the resulting annual energy cost (C_E) and energy revenue (R_E) streams were quantified. Note that the resource was dispatched on a consistent 365 day per year basis; no attempt was made to optimize the dispatch schedule, other than adhering to the discharge and recharge hours defined above.
3. After quantifying the revenue stream from on-peak energy sales, two distinct "avoided RA cost" calculations were computed by multiplying the efficiency factor coefficient with the monthly value of either the local or blended RA price (see Table 6.6.1), where each set of RA prices were assumed to escalate at 3% annually. In this analysis, we assumed that the passive ES system should offset 50% system and 50% local RA needs, while the avoided RA purchases for a dispatchable system should be valued at 100% local RA pricing. Additionally, a separate annual revenue stream for ancillary services was calculated by defining an "ancillary services factor" (F_{AS}) and then multiplying this factor with the corresponding energy revenue stream.

Given the above components, two distinct cumulative revenue values were then computed for two generic types of energy storage systems: a “passive” ES system and a “dynamically dispatchable” ES system. The annual revenue components for each of these systems were defined as follows:

$$\text{Revenue}_{[\text{passive}]} = R_E - C_E + F_E \times RA_{[\text{avoided cost, blended}]}$$

$$\text{Revenue}_{[\text{dynamic}]} = R_E - C_E + F_E \times RA_{[\text{avoid cost, local}]} + F_{AS} \times R_E$$

Finally, these forecasted annual revenue components were then summed up over both ten and twenty year time frames. The Net Present Value (NPV) of the resulting cumulative revenue components were then computed using a user specified discount rate of 3%, and the corresponding NPV estimates were divided by 10,000 kW to produce a final set of ES system values on a $ per kW of installed capacity basis.

13.2.3 Analysis and Results

Figure 13.2.1 shows a graph of passive and dynamic, generic ES system values for systems with expected 10-year and 20-year life cycles, having hypothetical energy efficiency factors of 0.6 to 0.9. The corresponding $/kW forecasts are shown in Table 13.2.1, respectively. Note that all of these forecasts also assume an ancillary service factor of 0.5 and a NPV discount rate of 3%.

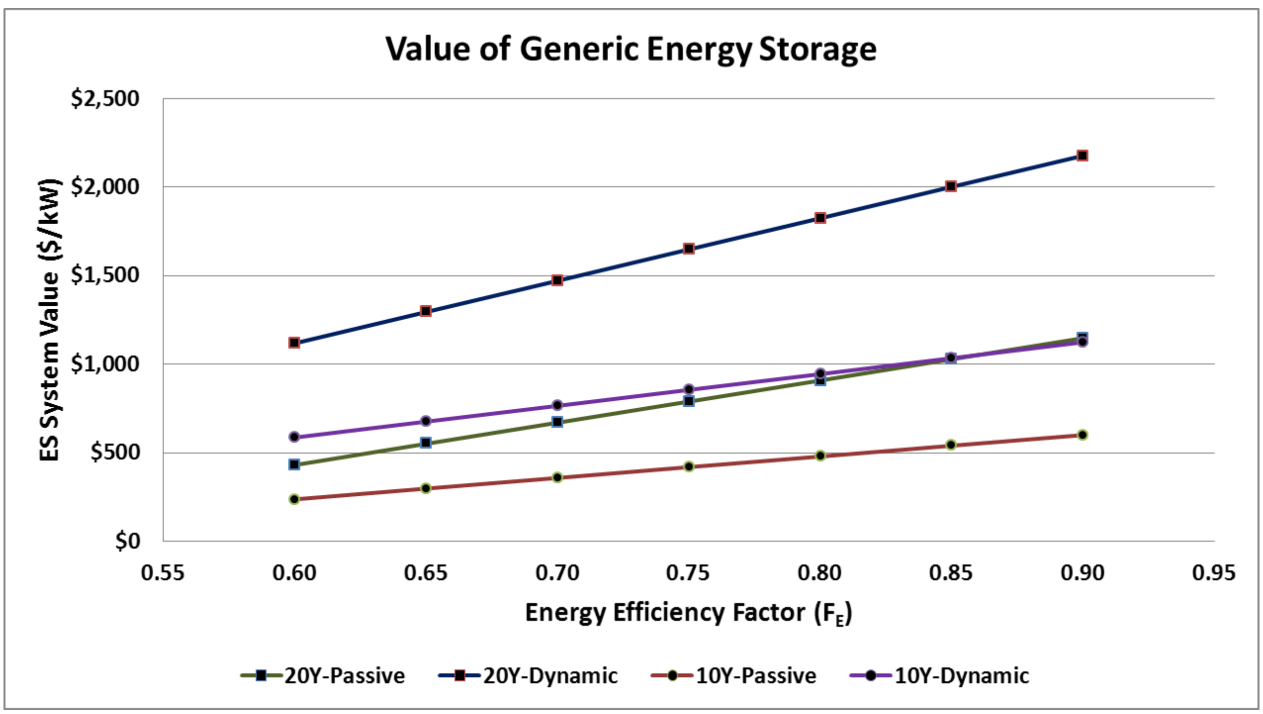


Figure 13.2.1. Forecasted NPV relationships for generic passive and dynamic energy storage systems, for an assumed FAS ratio of 0.5 and an annual discount rate of 3%.

While these valuation analyses are very high-level, some very useful information can still be extracted from these forecasting results. First, the forecasted value of all systems increase as the energy efficiency factor increases (an obvious and intuitive result); however, this increase is also more pronounced for systems with longer life expectancies. Second, a dynamically dispatchable system is forecasted to have significantly more value than a passive system. While an increase in value is to be expected, the magnitude of this increase is somewhat notable. For example, generic passive and dynamic systems with a 75% energy efficiency level and 20-year life span produce value/kW estimates of $789/kW and $1,648/kW, respectively (which exhibit more than an $850/kW difference). Clearly, this difference is due to the different assumptions about the avoided RA costs (blended versus local), as well as the assumption of an ancillary services revenue stream for the dynamic system (which is in turn determined by the assumed value of the F_{AS} coefficient). Thus, in addition to the assumed energy efficiency factor, it is clear that the system life expectancy and the passive versus dynamic characteristics significantly influence the derived system value.

Table 13.2.1. Forecasted NPV estimates for generic passive and dynamic energy storage systems, for an assumed FAS ratio of 0.5 and an annual discount rate of 3%. (Data shown graphically in Figure 13.2.1.)

	Forecasted NPV ($/kW): Passive & Dynamic ES Systems			
F_E Ratio	**20Y-Passive**	**20Y-Dynamic**	**10Y-Passive**	**10Y-Dynamic**
0.60	$431	$1,118	$237	$586
0.65	$551	$1,295	$298	$676
0.70	$670	$1,471	$358	$765
0.75	$789	$1,648	$419	$855
0.80	$908	$1,824	$479	$944
0.85	$1,028	$2,001	$540	$1,034
0.90	$1,147	$2,177	$600	$1,124

On a more practical level, these results can be used to provide 1^{st} order approximations to the value of various utility implemented energy storage systems having different system characteristics. As noted above, a dynamic system with a 75% energy efficiency level and 20-year life span has a forecasted NPV of $1,648/kW, assuming all of our various assumptions are reasonable. Likewise, if the same system only has a ten-year expected life span, then the forecasted NPV drops down to $855/kW, etc. Hence, these numbers can be used as rough, 1^{st} order guidelines when evaluating the design and implementation costs of various energy storage options (again, assuming that our various assumptions are reasonable).

Given the fact that the F_E, F_{AS} and life expectancy assumptions all exert a significant influence on the final NPV forecast, the following two empirical equations can be used to calculate a close approximation to these forecasts (± $5) for the following range of input variables:

$0.5 \leq F_E \leq 0.9$; $0.25 \leq F_{AS} \leq 0.75$; 10 years ≤ Life Expectancy (LE) ≤ 20 years

$$NPV(\$/kW)_{[passive]} = 63.4[F_E] - 49.8[LE] + 115.9[F_E \times LE]$$

$$NPV(\$/kW)_{[dynamic]} = 67.9[F_E] + 23.1[F_{AS}] - 50.4[LE] + 130.6[F_E \times LE] + 84.7[F_E \times F_{AS} \times LE]$$

Example: for a generic dynamic system with a 10-year life span, 80% energy efficiency and a 50% ancillary service factor, we obtain a $/kW NPV estimate of $945.5, which is very close to the $944 value shown in Table 13.2.1.

To summarize, under the current set of assumptions described above, a twenty-year, dynamically dispatchable ES system has a NPV of approximately $1,100 to $2,200 per installed kW of capacity, depending upon its energy efficiency level. The equivalent 10-year system has a NPV of about $600 to $1125 per installed kW of capacity. Likewise, for the range of energy efficiency levels considered here, a twenty-year passive ES system has a NPV of approximately $450 to $1150, and a 10-year system has a NPV of approximately $250 to $600, respectively.

13.2.4 Energy Storage Cost Overview

As stated previously, there are numerous new Energy Storage technologies at various stages of development in the marketplace. Different chemistries and configurations allow each battery type to provide different operating characteristics and therefore different "values" to an electric system. Similarly, the other traditional energy storage technologies (flywheels, pumped hydro, compressed air, and thermal storage) offer distinct services and values as well.

Table 13.2.2 presents cost data for some of these technologies. These data represent a cross-section of the various technologies that are currently available (at least in some commercial form). The cost data for electricity storage taken from the Sandia Handbook and chiller-based cost data are largely drawn from storage systems developed by investor-owned utilities or third party developers. A more complete report describing these data can be found in the following SCPPA report: "ENERGY STORAGE ECONOMICS ABSTRACT, *as prepared by: Southern California Public Power Authority, Energy Storage Working Group, March 2014".*

The lowest cost or price data for all samples of each technology are shown using two industry-standard measurements or units:

1) Installed Cost ($/kW); a measure of the cost of installation;
2) Levelized Cost of Operation ($/MWh); a measure of the cost of storage as an energy resource over time.

The levelized cost of energy or $/MWh is an industry-standard metric, as is the installed $/kW cost. As shown in Table 13.2.2, these minimum installed costs clearly exceed the forecasted NPV ($/kW) costs shown in Table 13.2.1. As such, RPU is continuing to evaluate multiple ES options, but as of yet has not identified a technology that would definitely provide a net positive cost benefit to our rate payers.

Table 13.2.2. Current industry standard cost data for various Energy Storage technologies.

Technology		Minimum Installed Cost ($/kW)	Minimum Levelized Cost ($/MWh)
Batteries			
	Advanced Lead-Acid	$2,500	$220
	Lithium-Ion	$1,950	$170
	Sodium-Nickel Chloride	$4,000	$610
	Sodium-Sulfur	$5,775	$292
	Zinc-Air	$3,200	$165
Flow Batteries			
	Iron-Chromium (Fe-Cr)	$3,100	$195
	Vanadium Redox	$6,000	$550
	Zinc-Bromine (Zn-Br)	$12,000	$1,800
Flywheels		$4,250	$380
Pumped Hydro		$5,500	$180
Compressed Air		$4,480	$120
Thermal			
	Chiller-based	$4,544	$99
	Refrigerant-based	$3,369	$127

13.3 An Ideal DSM/DR Program

The following analysis attempts to derive and calculate the potential value for an "ideal" Demand Side Management / Demand Response program. In this analysis, the term "ideal" implies that the adopted DSM/DR program would reduce our summer peak energy needs by up to 5%, but without reducing any of our volumetric energy sales. Conceptually, such a program would "smooth out" and reduce our projected 1-in-2 summer peaking needs, without impacting our retail revenue stream.

It should be noted that this analysis is somewhat hypothetical. Most DSM/DR programs that successfully reduce peak energy needs also result in either some volumetric energy sales reductions, or induce specific load shifting patterns that impact a customers demand charges (at least for commercial and industrial customers). However, in the following analysis we assume that no energy sales reductions and/or demand charge impacts occur. In practice, these assumptions would only be (approximately) valid for some type of residential load shifting incentive program; all other DSM/DR programs should incur at least some energy sales and/or demand charge reductions. Thus, the cost savings potential derived from the following analysis can also be taken to represent the maximum plausible savings potential (MPSP) that RPU would be expected to achieve under such a program.

13.3.1 DSM/DR Input Assumptions

The following input assumptions were used to model our hypothetical DSM/DR program:

- Peak load reductions occur during June through October. In June and October, RPU system peak loads are reduced by 2.5%; in Q3 (July – September), peak loads are reduced by 5%.
- There are no corresponding loss in energy sales, or changes in customer demand charges (i.e., retail sales revenues are unaffected by the DSM/DR program).
- Savings in system energy costs occur due to load smoothing (and shifting); i.e., less load purchased during the highest priced hours in the CAISO day-ahead market, and proportionately more load purchased during lower priced hours.
- ALL RA savings are valued at a blended RA price (see Table 6.6.1), where the RA pricing escalates at 3% annually.
- The DSM/DR program begins in 2016, achieves full enrollment that same year, and continues through 2033.

Based on the above set of assumptions, a hypothetical DSM/DR program was simulated in the Ascend production cost modeling environment by running both a normal and reduced set of strong growth peak load forecasts through 2033 and then differencing the energy and RA costs associated with these two simulation studies. (Note that since the monthly system load amounts were the same in both studies, the corresponding retail revenues for each study did not change.) The cumulative annual cost savings were then divided by the cumulative annual kW capacity reductions, in order to produce annual $/kW values for each cost component.

13.3.2 Analysis and Results

Based on the assumptions discussed in section 13.3.1, Figure 13.3.1 shows the amount of monthly capacity reductions achieved by our hypothetical DSM/DR program. Our 2016 monthly capacity reductions range from 10,500 (Oct) to 27,900 (Aug) kW, with a corresponding annual savings of 102,600 kW. By 2033, these monthly capacity reductions range from 13,200 (Oct) to 33,300 (Aug) kW, with a corresponding annual savings of 124,400 kW. Note that these capacity reductions (shown as negative numbers in Figure 13.3.1) result in approximately $300,000 (2016) to $600,000 (2033) in system energy savings, in addition to the previously discussed RA savings.

Upon dividing the annual energy and RA capacity cost savings by the associated annual capacity reductions, we derive the $/kW value of the MPSP. These forecasted values are shown in Figure 13.3.2 by savings type, respectively. In 2016, the MPSP for such a program is forecasted to be $8.02/kW; by 2033 this value increases to $13.06/kW. Approximately 63% of this savings is associated with avoided RA costs; the remaining 37% can be attributed to system load cost savings. Note that these components remain fairly stable throughout the simulation time horizon.

As discussed previously, these forecasted cost savings are based on an assumption that a DSM/DR program does not materially impact our retail revenues. Since most DSM/DR programs do tend to impact retail revenues, at least to some degree, our actual cost savings for such programs would quite likely be lower in practice. Additionally, note that the preceding analysis does not consider or quantify any other types of cost savings, such as avoided or deferred distribution system or environmental compliance costs, or other cost impacts, such as utility incentive payments or lost transmission revenues (see section 6.5). Of course, it is clearly important to also quantify all of these other cost savings and impacts (if any) when performing a detailed value assessment of a specific DSM or DR program.

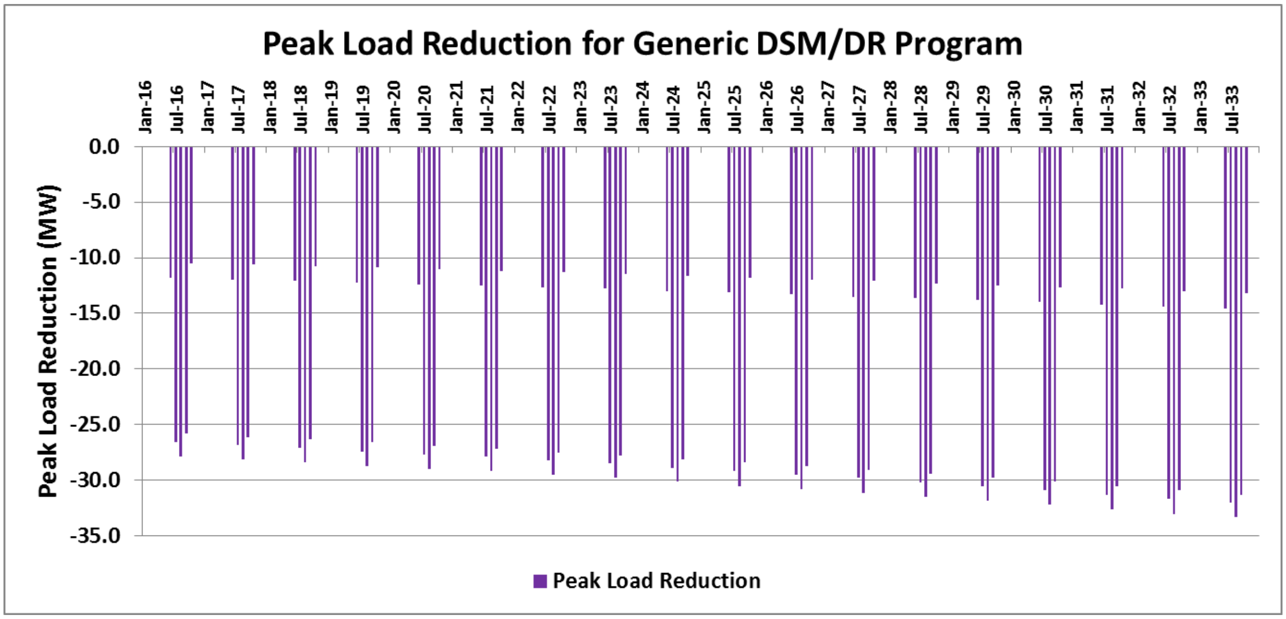


Figure 13.3.1. Monthly capacity reductions achieved under the hypothetical DSM/DR program.

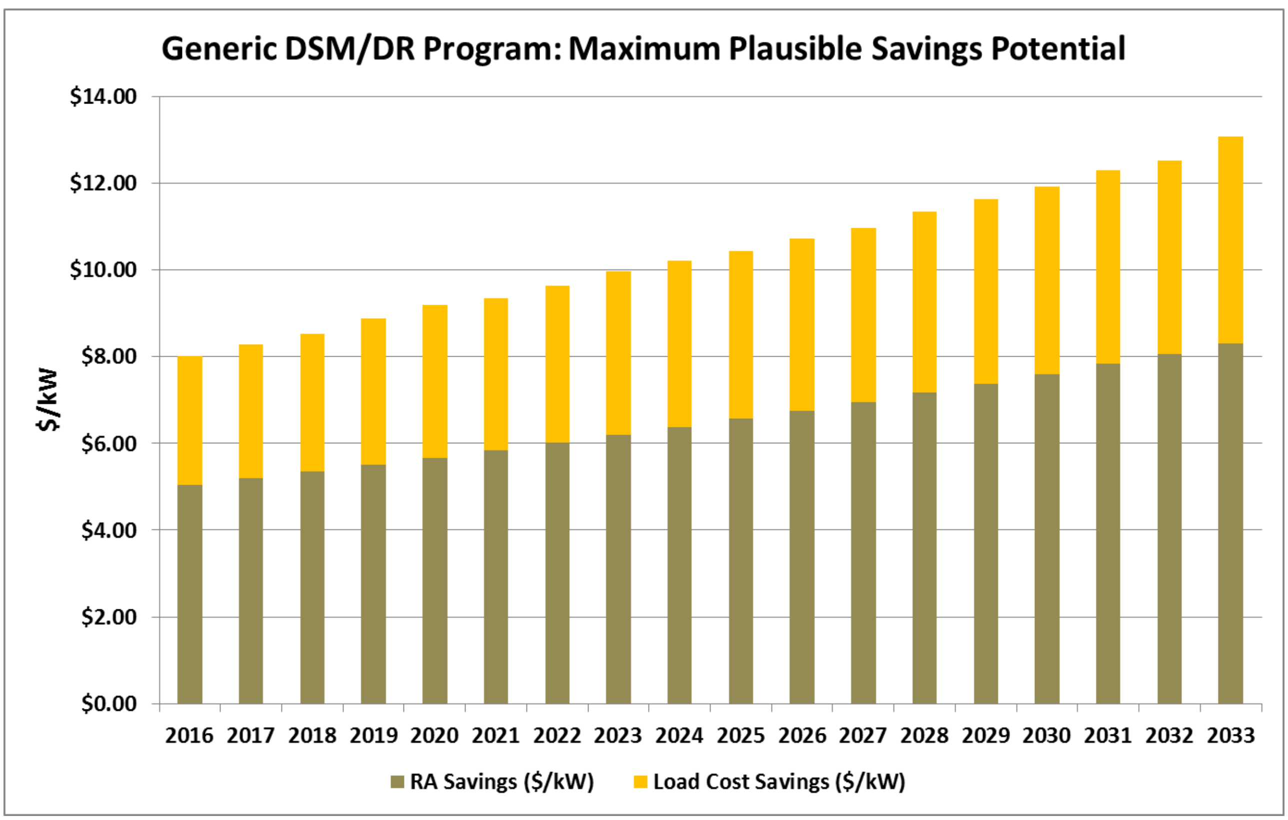


Figure 13.3.2. Corresponding annual $/kW value (maximum plausible savings potential) for the hypothetical DSM/DR program.

13.4 Solar PV Penetration in the RPU Service Territory

The first customer owned solar DG project was built in the RPU service territory back in early 2002. Additional customer owned solar installations occurred at a fairly minimal pace through 2008, but have accelerated considerably in the last four years. As of January 1, 2014, RPU had 6,659 kW of customer owned, installed solar AC capacity (nearly all roof-top solar). Figure 13.4.1 below shows the growth pattern over time since 2002; note that since early 2010, RPU has experienced a solar PV growth rate of about 1,500 kW of new capacity each year.

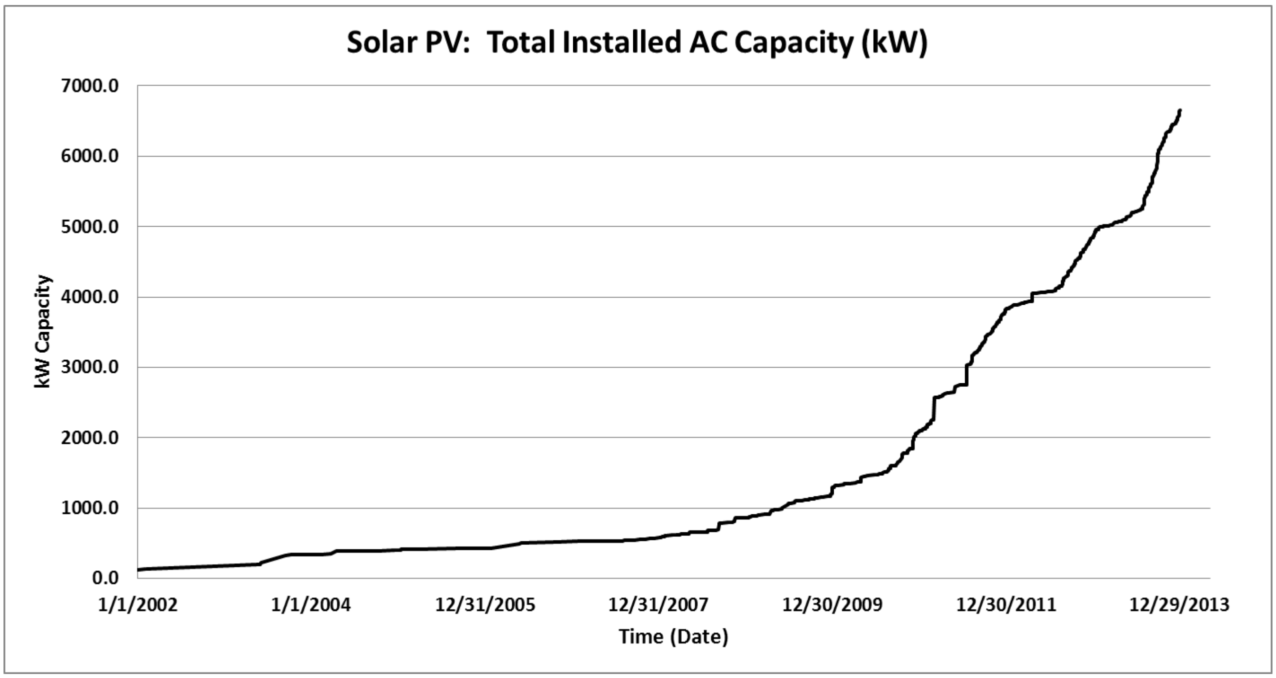


Figure 13.4.1. Total installed AC capacity of customer owned solar PV in the RPU service territory since 2002.

13.4.1 Background Information

Since the enactment of SB1, RPU has been encouraging the installation of customer owned solar PV through its solar rebate incentive program. (Historical details concerning rebate expenditures are available from the RPU Public Benefits Division.) Nearly all customer-owned, roof-top solar PV in the RPU service territory is currently administered under Net Energy Metering (NEM) contracts. Under these NEM contracts, RPU applies an off-set credit equal to the tiered billing rate for all of the customer generated energy registered by the meter, up to the annual customer usage levels. Thus, customers with solar PV systems that on average produce the same amount of electricity that is consumed on site effectively off set all of their billed energy usage with equally valued energy credits. Or equivalently, RPU effectively "buys back" all of the customer's solar energy at the current RPU tiered energy rates. For residential customers with higher than normal seasonal load consumption patterns (i.e., the typical residential customers who install solar PV systems), this means that RPU is typically crediting these customers either $0.1646/kWh (Tier 2) or $0.1867/kWh (Tier 3) towards their energy bills for their avoided energy demand. For commercial customers on our Flat rate energy schedule, the equivalent credits are either $0.1351/kWh (Tier 1) or $0.2064/kWh (Tier 2). Likewise, for commercial customers on our Demand rate energy schedule, these credits are either $0.1111/kWh (Tier 1) or $0.1217/kWh (Tier 2).

The costs versus benefits of customer side, distributed solar are currently being extensively debated at the CPUC. It is not our intention to review all of these various arguments here. Rather, this analysis is more narrowly focused towards determining the partial unmet revenue calculation for such NEM contracts, using the same criteria discussed in section 6.5 and 6.6. More specifically, our goal is to determine the partial net program impact ($/kW basis), based on the difference between our unmet retail revenues and our avoided power supply and capacity expansion costs. A methodology for computing this partial net program impact is presented in the next section.

13.4.2. Value Analysis: Modeling Inputs and Assumptions

In order to estimate the avoided energy and RA capacity costs associated with typical customer roof-top solar PV systems, we need to first specify the expected monthly system capacity and coincident peak reduction factors for such systems. The data presented in Table 13.4.1 quantify these monthly factors for a typical Southern California, south facing rooftop system with a 20% annual CF and a standard fixed array energy production profile. Note that the coincident peak reduction (CPR) factors were derived by taking the ratio of the expected solar energy production amounts (during our corresponding peak system hours) to the system production potential. For example, the July CPR factor of 0.345 implies that a 10 kW system should reduce RPU's peak RA needs by 3.45 kW, respectively.

Given these input factors, the monthly cumulative installed AC capacity amounts shown in Figure 13.4.1 were used to estimate the cumulative avoided system loads and peak energy amounts. These latter estimates were then added into our system load and peak forecasting equations as additional input variables (with the associated beta parameter estimates constrained to be equal to -1, and the remaining parameter estimates re-optimized). After re-calibrating these new (solar PV updated) forecasting equations, we then calculated the avoided system energy and RA capacity amounts for future years, assuming that RPU customers install the annual MW/year capacity amounts of new rooftop solar systems in our service territory shown in Table 13.4.2. (The 2014 and 2015 capacity numbers have been derived from current solar PV reservation requests; the remaining years represent reasonable future forecasts.) These energy and capacity amounts were then scaled up by 5% to account for the positive local DG effect of avoided distribution system losses, and valued at our current projected blended RA pricing (for the avoided RA capacity) and hourly SP15 energy price forecasts (for the avoided energy). Note that these estimates represent our future avoided capacity expansion and power supply costs, respectively.

Table 13.4.1. Assumed monthly CF (%) and CPR ratios for a typical south facing, fixed-array rooftop solar PV system in the RPU service territory (with a 20% annual CF).

Month	CF (%)	CPR (ratio)	Peak Hour (RPU system)
January	17.2	0	HE20
February	18.1	0	HE20
March	19.5	0	HE20
April	21.1	0.158	HE17 (50%) & HE20 (50%)
May	22.5	0.365	HE17
June	23.2	0.376	HE17
July	22.9	0.345	HE17
August	21.7	0.280	HE17
September	20.3	0.200	HE17
October	18.8	0.126	HE17
November	17.6	0	HE20
December	17.0	0	HE20

Table 13.4.2. Forecasted annual solar PV capacity additions by RPU customers throughout the RPU service territory. Note that the 2014 capacity figure includes a 3 MW solar PV system to be installed at the University of California, Riverside.

Year	**2014**	**2015**	**2016**	**2017 and beyond**
Capacity (MW/year)	6.0	3.0	3.0	2.0

To estimate our unmet revenue stream, we calculated the kWh of annual solar energy production and then multiplied this amount by $0.1596/kWh, which represents the (50%,25%,25%) weighted average of the arithmetic average of our two highest Tiers for the Residential, Commercial Flat and Commercial Demand schedules. Additionally, this billing factor was escalated at 2.5% per year after 2014, to adjust for potential future rate increases. Realistically, it is reasonable to assume that nearly all customer avoided energy charges fall into the highest two billing Tiers, provided that the installed capacity of the system produces an annual energy output that is less than 75% of the customer's average annual energy usage. Note also that we did not incorporate any additional utility incentive payments into the unmet revenue stream, even though RPU did transfer approximately five million dollars of internal utility reserve funds into the solar PV incentive program in 2012.

13.4.3. Analysis and Results

Figure 13.4.2 shows our current estimate of forecasted future installed solar PV capacity and the associated DG energy that will be produced in the RPU service territory. This DG energy and capacity reduces RPU's need to procure additional system energy and capacity (i.e., avoided energy and capacity costs), but also reduces our retail revenues (i.e., an unmet revenue stream). Currently, we forecast that RPU will see 12.7 MW of installed customer solar by 2014, increasing to 32.7 MW of installed capacity by 2023 (assuming that 2 MW of new capacity comes on-line each year after 2017). In turn, this will result in 17,400 MWh of energy generation in 2014, increasing to 55,800 MWh by 2023.

Table 13.4.3 shows the pertinent cost and revenue estimates for determining the partial net impact calculations associated with our customer installed solar PV systems in the RPU service territory. As shown in the final column of this table, we expect RPU to incur an increasing net revenue loss over time as more customer based, solar PV systems come on line. This effect is due to the fact that RPU credits each customer for their energy generation at our current residential tier rates, but these rates significantly exceed our avoided energy and capacity costs. This result actually should not be surprising, since our rates are designed to recover all of RPU's bundled operating costs (i.e., energy, capacity, distribution system, O&M, personnel costs, and our GFT, etc.).

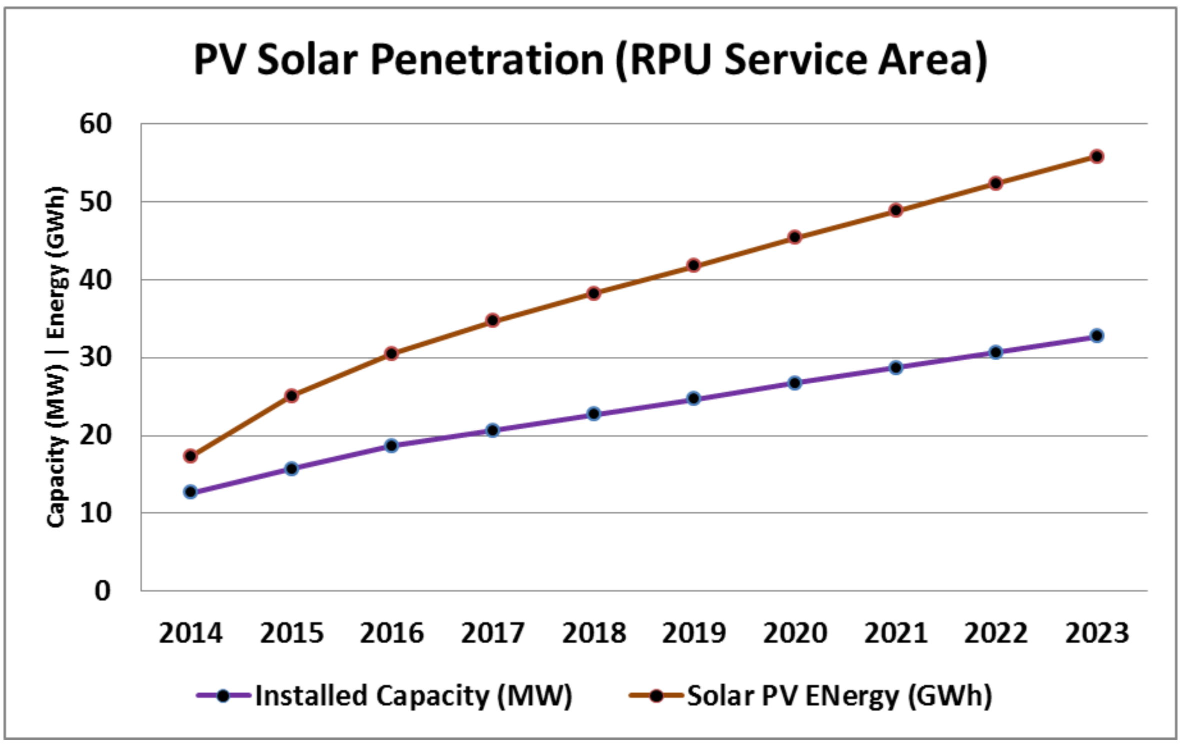


Figure 13.4.2. Forecasted future customer solar PV capacity and the associated DG energy in the RPU service territory.

Table 13.4.3. Cost and revenue estimates for determining the partial net impact calculations for customer installed solar PV systems in the RPU service territory.

YEAR	Installed Capacity (MW)	Load Reduction (MWh)	Avoided Energy Cost	Avoided RA Cost	Unmet Revenue	Partial Net Cost to RPU
2014	12.66	17.36	($746,087)	($66,307)	$2,770,048	$1,957,654
2015	15.66	25.09	($1,097,719)	($95,962)	$4,103,791	$2,910,110
2016	18.66	30.43	($1,360,770)	($119,314)	$5,102,046	$3,621,961
2017	20.66	34.68	($1,610,082)	($139,706)	$5,960,652	$4,210,864
2018	22.66	38.20	($1,838,151)	($158,377)	$6,728,765	$4,732,236
2019	24.66	41.71	($2,105,229)	($178,043)	$7,531,555	$5,248,282
2020	26.66	45.33	($2,406,838)	($198,746)	$8,390,399	$5,784,815
2021	28.66	48.74	($2,619,248)	($220,531)	$9,246,234	$6,406,454
2022	30.66	52.25	($2,861,376)	($243,445)	$10,160,751	$7,055,931
2023	32.66	55.77	($3,121,219)	($267,535)	$11,115,220	$7,726,467

Based on the data shown in Table 13.4.3, we can readily calculate the kW normalized, partial net unmet revenue effect for customer based solar PV systems. For 2014, this normalized estimate is $154.64 per kW of installed capacity. Figure 13.4.3 shows our ten-year normalized unmet revenue forecasts; note that these values increase over time, eventually reaching $236.57 per kW in 2023.

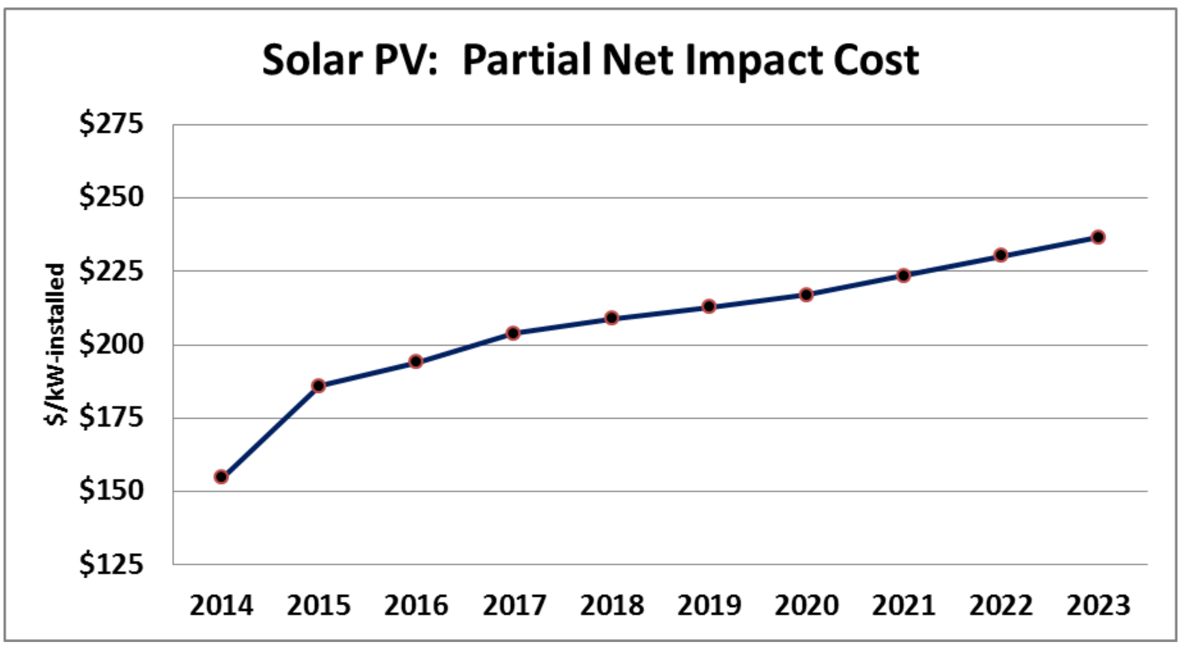


Figure 13.4.3. Ten-year normalized partial net unmet revenue forecasts ($/kW-installed).

Unfortunately, the cumulative net unmet revenue stream also increases significantly over time. In turn, this implies that our non-solar customers will need to contribute an increasing percentage of their electricity bills towards this "solar subsidy". Figure 13.4.4 shows the forecasted additional annual costs that our typical non-solar customer must pay RPU to support our current NEM program (i.e., for a typical customer who uses 1,000 kWh of electricity a month). This figure is forecasted to be about $10.70/year in 2014, and should increase to almost $36/year by 2023, if current installation trends continue as expected.

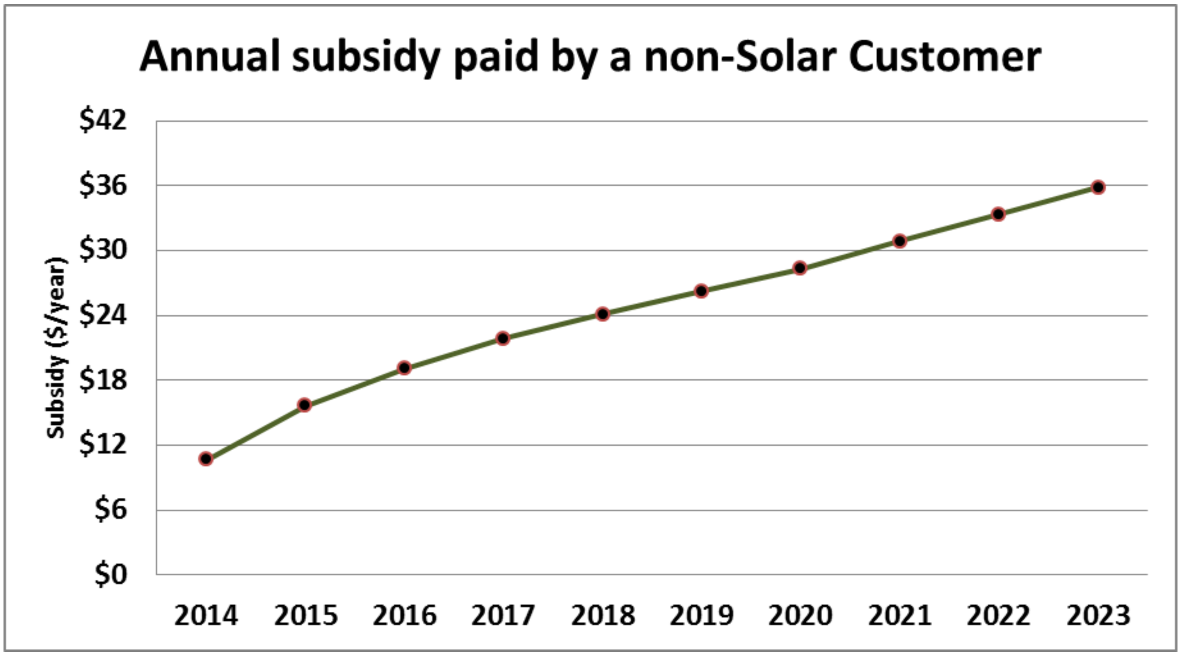


Figure 13.4.4. Forecasted additional annual cost that a typical RPU non-solar customer must pay to support the current NEM program (i.e., for a typical customer use uses 1,000 kWh of electricity a month).

13.4.4. Additional Comments

The previous analysis incorporates certain assumptions that deserve further comment. Following the logic presented in Chapter 6, this analysis quantifies the partial net unmet revenue effect only. In other words, we have not attempted to quantify any additional positive benefits from either (i) avoided or deferred RPU distribution system costs, or (ii) avoided environmental compliance costs or other RPS benefits. Additionally, we have not quantified any additional negative costs associated with either (i) utility incentive payments, or (ii) lost CAISO TAC revenues. Should significant dollar values be assigned to one or more of these categories, the impact calculations would be expected to yield different forecasts.

However, it is unlikely that any of the additional components discussed above are material enough in nature to significantly change these results. With the exception of a few circuits supporting commercial areas in the center part of our service territory, our distribution system is not currently stressed. The installation of additional customer solar PV systems are not currently expected to significantly impact (or defer) our distribution system costs, particularly since at least half of the capacity of these systems are being installed in our newer residential areas. Likewise, while RPU can receive some minimal RPS benefits from increasing solar DG penetration in our service territory, the vast majority of the environmental benefits often attributed to customer PV installations tend to be society related impacts that are simply beyond the scope of RPU's immediate budget (and exceedingly difficult to effectively quantify or value).

With respect to additional costs, until recently all of our utility incentive payments for customer solar PV rebates had been funded from the 2.85% AB2021 EE/conservation fee (collected on all customer bills). Thus, assuming that RPU does not again elect to internally fund this rebate program, we do not need to factor in additional incentive payments into the cost calculations. Finally, we should probably factor in lost CAISO net revenues (defined as CAISO Transmission Revenue Requirement revenues less CAISO Transmission Access Charge Costs times the lost reduction—or about $6.44/MWh as of December 31,2 013), but currently these costs should be at least an order of magnitude smaller than our unmet retail revenues.

In summary, although they have not yet been fully quantified, none of the additional cost or revenue components discussed above appear to be material enough to change our fundamental conclusion concerning our NEM customer solar PV program. RPU's rates (like most Municipally-Owned Utilities) are currently structured with the vast majority of revenues being volumetrically based, even though the majority of RPU costs are fixed in nature. Unfortunately, this program is promoting a paradigm where our non-solar customers essentially subsidize our solar PV customers, and this subsidy is only projected to grow over time. It seems clear that our legacy rate structures that have existed historically may not be promoting the same rate-making principles and policies used to at their inception. Hence, these policies and principles may need to be modified to best serve the utility business model of the future.

This conclusion raises a number of problematic issues for RPU. For example, how can our utility promote and encourage DG resources within our service territory that effectively benefit all of our customers, as opposed to just those customers who choose to install such systems? Likewise, how can RPU balance state policy mandates designed to reduce electricity consumption with a bundled rate structure; e.g., is this even financially possible? And more broadly speaking, how should RPU position itself for a future where many of our more affluent customer owners may be moving towards a greater degree of energy independence (or perhaps more correctly, a state of energy inter-dependence)? These are the core questions that RPU must effectively answer, if we are to successfully promote an increasing amount of sustainable DG (and EE/DSM) in our service area.

13.5 Electric Vehicles (EVs)

In 2012, California Governor Jerry Brown set a state target of getting 1.5 million zero-emission vehicles on California roads by 2025. Achieving the Governor's target with battery electric vehicles would represent an additional load of 10,000 MW on the grid. Accounting for plug-in hybrid electric vehicles, total load exceeds 30,000 MW, which represents nearly 60% of the summer peak load in 2013. This aggressive goal is being pursued by California due to the potential for EVs to dramatically reshape the way in which electricity is stored, managed and regulated on the electrical grid.

Figure 13.5.1 shows the current range of forecasts for EV penetration in the California market. As shown in this figure, the estimated number of EVs in the IOU service territories in 2012 is still quite minimal (black diamond). However, the potential to reach the 2025 1.5 million vehicle mark does exist, if EVs were to become embraced by California consumers.

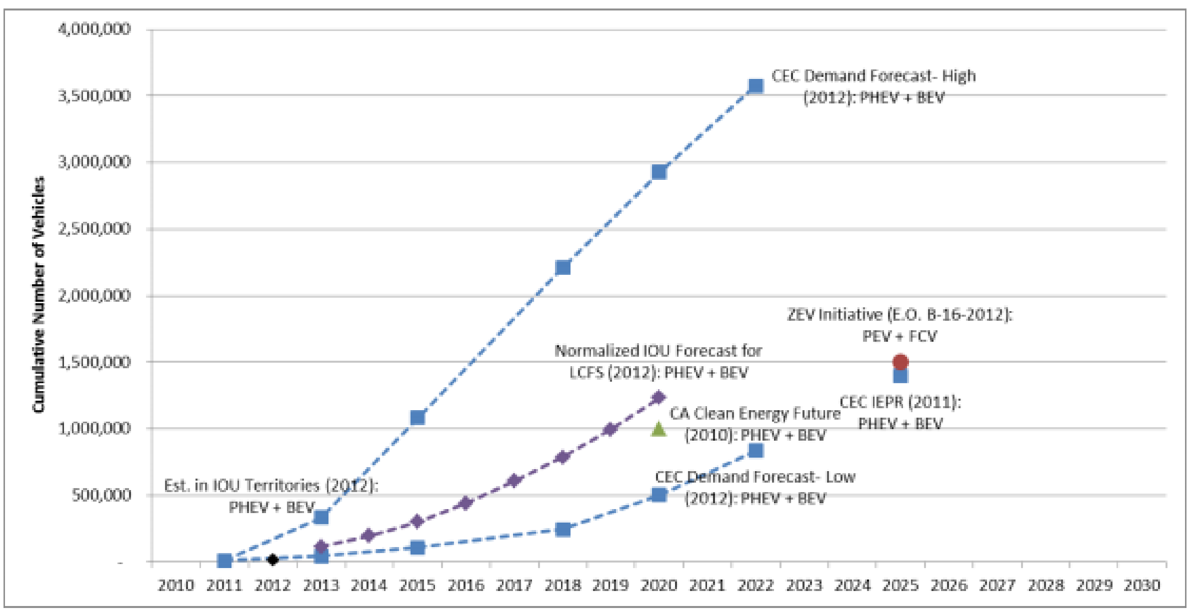


Figure 13.5.1. Various EV penetration forecasts for the state of California.

The remainder of this section discusses some of the potential advantages that EVs could offer to the electrical grid, and describes pilot programs that are currently underway to study EV impacts and advantages.

13.5.1 EV Potential for Energy Storage and Demand Side Management

Electric-drive vehicles (hybrid, battery, and fuel cell vehicles), can generate or store electricity when parked, and with appropriate connections can feed power to the grid. In the utility industry, this is commonly called “vehicle-to-grid” (V2G) power. Personal electric vehicles, like all personal vehicles are utilized on average only 4% of the time for transportation, making them potentially available the remaining 96% of time for a secondary function. Figure 13.5.2 below shows an estimate of the percent of time for vehicle usage by time of day; clearly the V2G potential is quite large, providing that it can be harnessed in a cost-effective manner.

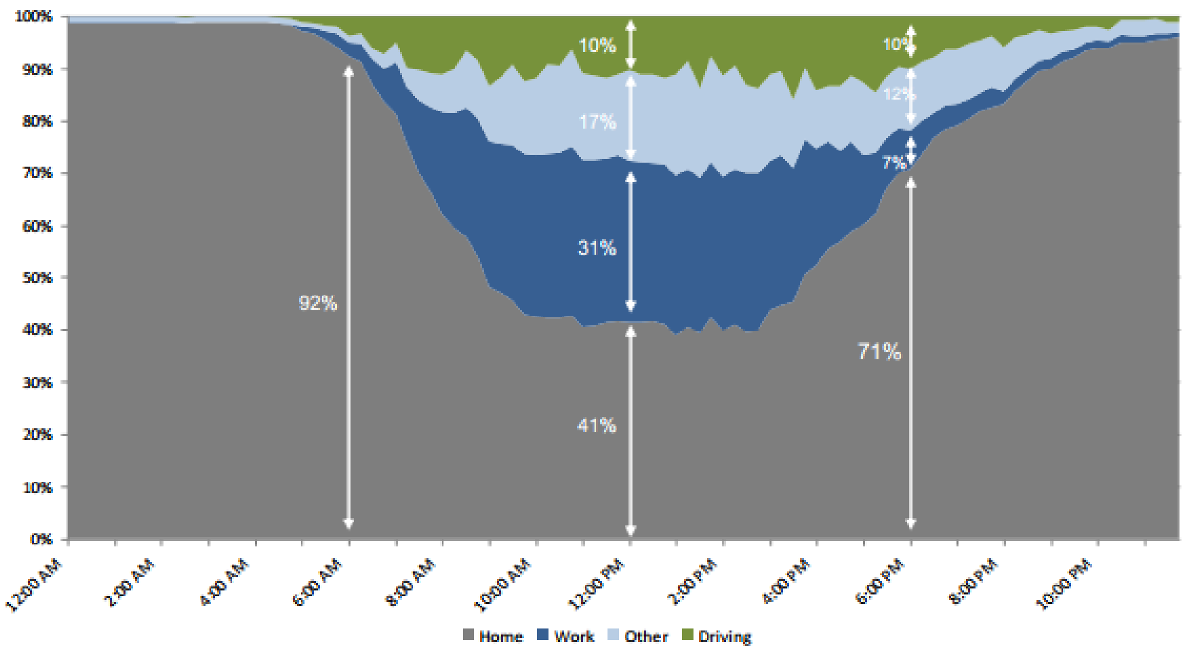


Figure 13.5.2. Percent of time of typical vehicle usage by time of day.

The basic V2G concept is based on the fact that battery, hybrid, and fuel cell vehicles can all send power to the electric grid, power that all three already generate or store internally (V2G Project, University of Delaware). For battery and plug-in hybrid vehicles, the power connection is already there. For fuel cell and fuel-only hybrids, an electrical connection would need to be added. In either case, in theory these vehicles can either directly interact with the distribution gird (Figure 13.5.3), or interact as a component in an energy efficient building system or micro-grid (Figure 13.5.4).

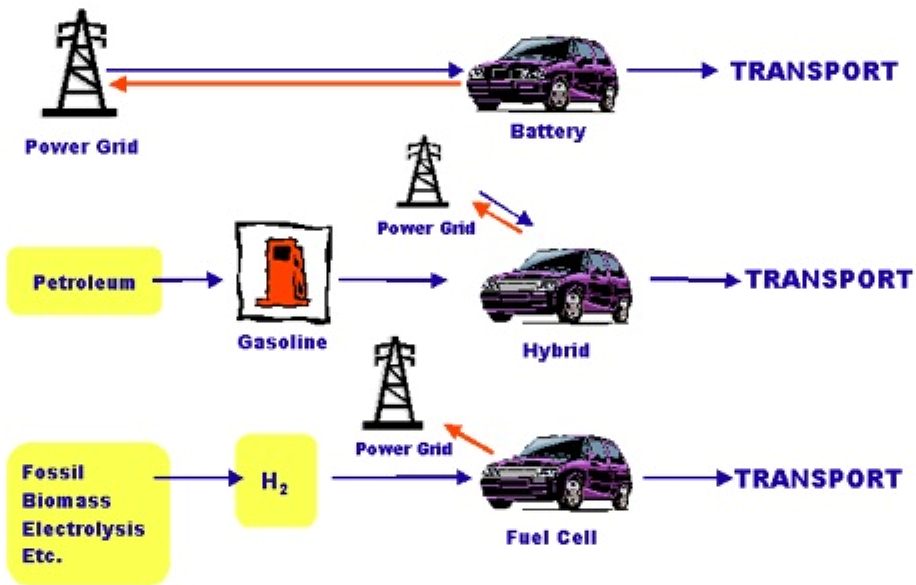


Figure 13.5.3. Potential for battery, hybrid, and fuel-cell vehicle interaction with the power grid.

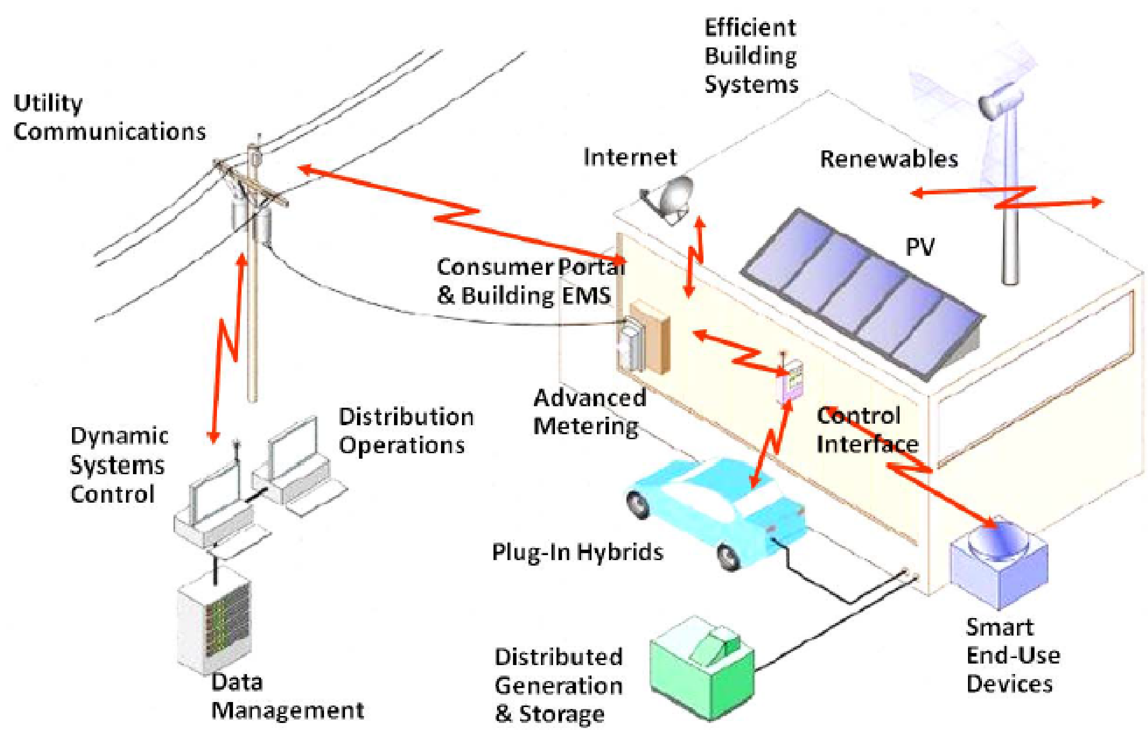


Figure 13.5.4. Plug-in hybrid vehicle as a component to a micro-grid system.

A number of universities and national research centers have recently studied (and continue to study) the potential for integrating EVs into the electrical grid. In a 2010 study conducted by Sandia National Laboratories, the following V2G benefits and market potentials were identified for EVs.

- Electric energy time shift
- Electric supply capacity
- Load following
- Area regulation
- Voltage support
- Time-of-use energy cost management
- Demand charge management
- Renewables energy time shift
- Renewables capacity firming
- Wind generation grid integration

More generally, a consensus has been developing around the potential of EVs to impact different electrical markets, as described below:

1. **Base-load power**
   Studies have shown that EDVs cannot reliably provide base-load power at a competitive price, due to limited energy storage, and high energy costs per KWh. Base-load power applications do not exploit EVs quick response times or low standby costs.

2. **Peaking power**
   Using EVs to generate peak power may be economic under some circumstances. However, typical peak power needs range from 3 to 5 hours, which for EVs is possible but difficult due to on-board storage limitations. This limit might be overcome if power was drawn sequentially or managed cleverly.

3. **Spinning reserves**
   Spinning reserve contract arrangements are favorable for EVs, since they are paid for just being plugged in, while typically incurring relatively short periods of generation.

4. **Regulation**
   EVs greatest strengths are their quick response time, low standby costs, and more importantly, their ability to both draw power from and feed power to the grid. This makes them ideal for providing regulation services.

Finally, there is considerable interest in exploiting the potential of V2G to support increasing levels of renewable energy development. The two largest renewable energy sources, solar photovoltaic (PV) and wind, are both intermittent. Some studies have suggested that V2G could enable intermittent renewable energy to provide much of society’s energy needs, while keeping the electric grid stable and reliable. To date, these studies are highly conceptual in nature, although a number of pilot programs are now being launched to examine the practical application(s) of the V2G concept.

13.5.2 Current and/or Recent V2G Pilot Programs

The following V2G pilot programs are either currently underway or have been recently launched in the state of California.

Department of Defense & EV Services suppliers V2G Project

This project is examining the potential to aggregate EV wholesale participation in the ISO market for Energy and Ancillary Services. The potential for bi-directional power flow is also being studied as a demand side load resource. The two goals of this project are (i) to develop an understanding of how EVs can participate in the ISO wholesale energy market, and (ii) assist in the efforts of integrating additional amounts of variable and intermittent renewable resources while maintaining grid reliability.

Southern California Edison EV Charging Station Pilot Program

SCE intends to deploy up to 233 EV charging stations at SCE facility parking lots, which includes 50 that were previously installed under earlier funding. User load will be measured at each charging station, and a user fee will be paid by the individual consumer using a vendor supplied billing and settlement service. Utility load survey metering is already installed on most charger circuits for monitoring load impacts and will be expanded to all new charger circuits. This metering will be sufficient to measure ongoing load profiles for aggregate charging on each circuit and the effectiveness of various pilot program strategies.

Communication from individual charge stations to the vendor back office for billing and settlement will be required and will serve as the most granular measurement of effectiveness. Load management, price signaling, and load reductions will be controlled by Open ADR 2.0 messaging via either the charge station supplier's back office network or alternatively through a system integrator network. The goal of this program is to determine the impacts of PEV charging on building load shapes in numerous facilities of varying sizes, workforce populations and demand profiles.

SDG&E EV TOU Project

In a recent study conducted by San Diego Gas & Electric, SDG&E customers with EVs were randomly assigned to 1 of 3 experimental TOU rates specifically designed to support EV charging. Customer charging behavior was analyzed across these TOU rate structures. The goals of the SDG&E's rate experiment were to understand the potential impact of EV technology on the electric utility infrastructure and identify methods to mitigate grid impacts.

PG&E EV Pilot Study Program

Pacific Gas and Electric recently launched a multi-phase EV pilot study program designed to assess the following electric vehicle integration issues:

- Requirements Needed To Obtain Utility Benefits: Determine the requirements needed for PG&E to incorporate DR from EVs into its operational & planning groups and the associated benefits that would accrue to DR EV providers.
- Communication Capabilities: Evaluate the technical capability to provide timely two-way communication, such as price & Direct Load Control messages, to the EVs over the AMI network and/or broadband network using national standards
- DR Response Characteristics: Evaluate how quickly and in what manner EVs respond to signals to alter charging patterns based on the EV battery's state of charge and user profiles, both on an individual basis and in aggregate.
- Customer Response: Evaluate customers' charging patterns, preferences, behavior, and reactions to utility interaction with EV charging.
- Second Life Customer: Evaluate and engage various automaker OEM and EV vendor channels to find the best mechanism to encourage demand response adoption by EV customers.
- Second Life Battery Integration: Evaluate the costs & benefits of utilizing second life EV batteries to provide various grid services.

Other State of California Programs

In addition to these various pilot programs, California has recently enacted legislation and/or executive orders designed to encourage the growth of the EV market. Two examples of this are the "California Clean Fuels Outlet Regulation" and the "EV Executive Order and Action Plan".

The Clean Fuels Outlet (CFO) Regulation is intended to provide outlets of clean fuel to meet the needs of those driving clean, alternative fuel vehicles. This policy proposes adding a regulatory review for plug-in EVs. Electricity is currently excluded from the definition of a designated clean fuel in CARB regulation. However, staff are proposing to add regulatory language that requires CARB to evaluate the development and usage of workplace and public charging infrastructure, and make recommendations for further actions two years following adoption of the regulation.

The EV Executive Order and Action Plan established several milestones on a path toward achieving 1.5 million EVs in California by the year 2025. This 2013 ZEV Action Plan identifies specific strategies and actions that state agencies will take to meet milestones of the executive order. This Executive Order also (i) provides early funding for EV charging and fueling infrastructure, (ii) dictates pricing transparency for ZEV charging and fueling, and (iii) establishes consistent statewide codes and standards for EV infrastructure.

13.5.3 RPU Strategic Planning for EVs and V2G Potential

Currently, the City of Riverside has seen very minimal EV penetration in its service territory. Between January 2008 and August 2013, RPU had paid out utility rebates for just 87 EVs (and 55 hybrids). Additionally, in September 2013, RPU launched a new Domestic TOU rate designed for households with electric vehicles. However, as of May 2014, only three customers had signed up for this rate structure.

RPU's current strategy for leveraging future V2G potential can probably be best described as "wait and see". Although the state is aggressively pushing the adoption of this technology, there is grossly insufficient EV penetration in our service territory to justify any V2G infrastructure investments at this time. Should this trend change (i.e., improve) over time, RPU will revisit this issue and re-examine how to best leverage the V2G potential across its distribution system.

14 Conclusion

As stated in the Introduction, in this 2014 Integrated Resource Plan we have reviewed and analyzed both intermediate term and longer term resource portfolio and energy market issues relating to RPU. The five primary goals of this IRP were broadly summarized as follows:

- Goal 1. Provide an overview of Riverside's (a) energy and peak demand forecasts, (b) current generation and transmission resources, and (c) existing electric system.

- Goal 2. Review and assess the impact of important legislative and regulatory mandates imposed by various state or regional agencies (California Energy Commission, California Air Resources Board, South Coast Air Quality Management District, etc.), along with the impact of important active or proposed California Independent System Operator (CAISO) stakeholder initiatives.

- Goal 3. Summarize and assess our current set of Energy Efficiency (EE) and Demand Side Management (DSM) programs, and examine if and how these EE/DSM programs can be further expanded to help offset our future energy needs.

- Goal 4. Quantify our expectations and uncertainty around our intermediate term (five-year forward) power resource forecasts, specifically with respect to meeting our (a) projected capacity and resource adequacy needs, (b) renewable portfolio standard (RPS) mandates, (c) carbon emission goals and mandates, (d) power resource budgetary objectives, and (e) cash-flow risk metrics.

- Goal 5. Examine and analyze certain critical longer term power resource issues, specifically with respect to how these issues are forecasted to impact our future cost-of-service. The primary longer term issues examined in this IRP include (a) projected load growth impacts, (b) timing impacts associated with the termination of our Intermountain Power Project (IPP) contract, (c) general market price shock impacts (i.e., sensitivity analyses), (d) potential replacement options for our IPP contract, (e) cost impacts associated with higher RPS mandates, and (f) value and/or cost analyses of important secondary issues (e.g., energy storage, customer solar PV, electric vehicles, etc.).

The chapter organization and layout has sequentially followed the general goals discussed above; i.e., background information has been presented in Chapters 2-4, legislative and regulatory mandates and initiatives were discussed in Chapter 5, our EE and DSM programs were presented in Chapter 6, forward market views were discussed in Chapter 7, RPU's intermediate term portfolio forecasts were discussed in detail in Chapter 8, and multiple longer term resource planning issues have been analyzed in Chapters 9-13. Overall, we have attempted to compile and present information in these chapters that addresses our five primary IRP goals in a comprehensive and analytical manner.

14.1 Summary of Findings

In this final chapter we will provide a high-level review each of these primary goals, specifically with respect to data and analyses presented in this IRP. Succinct summaries of our findings are presented in the following sections.

14.1.1 Goal 1: Summarize RPU Background Information

In Chapter 2 we provided an overview of RPU's long-term energy and peak demand forecasting methodology. This overview included a discussion of our econometric forecasting approach, key input variables and assumptions, and pertinent model statistics. Our load and peak demand models are conditioned on two key economic drivers (employment levels and PCPI forecasts), in addition to various weather inputs and seasonal adjustments. We also derived and presented our high (strong) and low (weak) 2014-2033 output energy and peak demand forecasts in Chapter 2. Recall that our long term strong growth forecasts call for 2.4% and 1.1% annual load and peak growth, respectively, while our weak growth forecasts exhibit annual load and peak growth rates of just 0.5%.

In Chapter 3 we provided an overview of RPU's long term resource portfolio assets, including our existing resources, future renewable resources (currently under contract), and recently expired contracts. We also described our transmission resources in Chapter 3, along with our transmission control agreements with the CAISO. RPU currently either owns or has contracts for seventeen different generation resources that are based on multiple types of thermal or renewable technologies. Altogether, our current resource portfolio provides RPU with about 550 MW of nameplate capacity; within the next two to three years this number should increase to about 656 MW of capacity, as new renewable resources come online. By 2019, if all of our new renewable PPA's come to fruition, Riverside Public Utilities will serve approximately 37% of its retail load using renewable resources.

In Chapter 4 we briefly reviewed RPU's existing electric distribution system and described how it operates. RPU is a vertically integrated utility that operates electric generation, sub transmission, and distribution facilities, receiving the vast majority of its system power through the regional bulk transmission system operated by the CAISO. Undoubtedly, the Riverside Transmission Reliability Project (RTRP) represents the most important anticipated change to our distribution system. If RTRP is fully adopted, SCE will expand its regional electrical system to provide Riverside a second source of transmission capacity to import bulk electric power. This expansion will be accomplished by (i) the creation of a new SCE 230 kV transmission interconnection, (ii) construction of a new SCE substation, (iii) construction of a new RPU substation, and (iv) the expansion of the RPU 69 kV system. Once completed, RTRP will provide RPU with long-term system capacity for load growth, along with needed system reliability and flexibility.

14.1.2 Goal 2: Review Important Legislative and Regulatory Mandates

In Chapter 5 we reviewed and discussed relevant legislative, regulatory and stakeholder issues that will have significant impacts on the California electric industry in the foreseeable future, specifically to the markets run by the CAISO. In particular, the following nine legislative, regulatory, and CAISO mandates and initiatives are expected to significantly impact RPU.

SB X1-2 – Renewable Portfolio Standard (RPS)

The California state legislature passed SB X1-2 RPS in 2011 which mandates that in-state electric utilities procure 33% of renewable resources to serve retail loads by 2020. In addition, the procurement of renewable resources must be predominantly from in-state renewable resources, e.g., starting 2017, 75% of renewable resources within the target must be located in-state and no more than 10% can be from tradable renewable energy credits (TREC's). With respect to the current RPS paradigm, Riverside is already well positioned to comfortably exceed all state specified renewable mandates for at least the next 10 years (e.g., through 2023). Our recent PPAs for the new renewable generation assets should ensure that RPU can serve approximately 37% of its retail load from in-state RPS resources by 2019.

AB 32 – California Greenhouse Gas (GHG) Reduction Mandate

The state legislature passed AB 32 in 2006 which mandated statewide reduction of GHG emissions to 1990 levels by calendar year 2020. The California Air Resources Board (CARB) is the lead regulatory agency implementing the AB 32 directives. CARB finalized its implementation regulations in early 2012 and the compliance requirements commenced as of January 2013.

RPU is a covered entity under Cap-and Trade as a First Deliverer of Electricity for both operating electricity generating facilities in California, and also for importing electricity into California. As a covered entity, Riverside is required to report annual greenhouse gas emissions to the CARB under the CARB's Mandatory Reporting Regulations (MRR), and surrender the appropriate amount of free Carbon allowances to cover these emissions. As shown in Chapter 8, the vast majority of Riverside's covered emissions are associated with power imported from the Intermountain Power Project (IPP).

At this time it is unclear whether CARB will be mandated to continue issuing a reduced amount of free allowances after 2020. However, RPU will not be able to substantially reduce its GHG footprint until our IPP coal contract expires. Thus, the major economic risk to RPU under this program occurs after 2020. In the absence of additional free allowances after 2020, RPU could potentially face a 20 million dollar per year emission liability (assuming annual IPP emissions of 800,000 tons at $25/ton).

SB 1368 – Emission Performance Standard

The state legislature passed SB 1368 in 2006 which mandates that electric utilities are prohibited to make long term financial commitments (commitments greater than 5 years in duration) for generating resources with capacity factors > 60% that exceed GHG emissions of 1,100 lbs/MWh. SB 1368 essentially prohibits any long term investments in generating resources based on coal. Riverside has ownership entitlement rights to 136 MW of the Intermountain Power Project, which provides approximately 40% of RPU's annual power needs. Since IPP has a GHG emission factor of approximately 2,000 lbs/MWh, under SB 1368 Riverside is precluded from renewing its IPP Power Purchase Contract at the end of the current term in June 2027.

AB 2514 -- Energy Storage

AB 2514 “Energy Storage Systems” was signed into law on September 29, 2010. The law directs the governing boards of publicly-owned utilities (POUs) to consider setting targets for energy storage procurement but emphasizes that any such targets must be consistent with technological viability and cost effectiveness. On February 17, 2012, as per the statute, the Riverside Board of Public Utilities opened a proceeding to investigate the various energy storage technologies available and determine if Riverside should adopt energy storage procurement targets. In October 2014 RPU concluded that there are no market ready, cost effective energy storage solutions that can be immediately adopted. However, RPU is continuing to currently investigate various energy storage technologies and assessing the benefits that these technologies might provide to its electricity system.

Governor’s Distributed Generation (DG) Mandate

In 2012, Governor Jerry Brown issued an executive directive to develop 12,000 MW of distributed generation resources within the next 10 years. The primary goal of this mandate is to better facilitate state transmission/distribution planning with respect to the integration of renewable resources. Currently, Riverside is working towards fulfilling at least some of its DG mandate via the development of utility owned solar PV installations within the city limits. The largest of these is our 7 MW solar PV project on the Tequesquite Landfill site. However, RPU is also currently exploring opportunities to build smaller assets throughout its service territory, since additional DG development may be required to fulfill this mandate.

CAISO Energy Imbalance Market (EIM) Initiative

This CAISO market initiative started as an attempt within the Western Electricity Coordinating Council (WECC) to improve regional diversity in the operation and utilization of power resources to integrate an increasing amount of intermittent resources throughout the Western US. In 2012, the CPUC requested that the CAISO develop a market paradigm that could improve on the market efficiency while taking into account the regional diversity in load and resources.

The CAISO has filed the MOU with the FERC and is currently refining the market implementation design. The CAISO implemented this new EIM in the fall of 2014, in conjunction with the launch of the CAISO 15-minute market (described below). However, major EIM cost allocation and real time balancing issues still need to be adequately resolved, if this EIM initiative is to be successful at not burdening CAISO LSEs with disproportionate costs.

FERC Order 764 – 15-Minute Market Initiative

FERC issued a rulemaking in late 2011 mandating the regional transmission organizations to consider and implement market structures to accommodate the increasing amount of intermittent resources that are anticipated to come on line in the foreseeable future. The CAISO responded to this FERC directive with its 15-minute market initiative -- with the goal of scheduling and financially settling all transactions through the CAISO on a 15-minute interval basis. The implementation of the 15-minute market has impacted import power prices and PIRP resources (predominantly the clearing prices of wind and solar resources). Additionally, the implementation of CAISO 15-minute market has added additional complexity and workload to Riverside's market scheduling and settlement functions.

CAISO Flexible Resource Adequacy and Enhanced Must Offer Obligation (FRAC/MOO)

Given the increasing amount of intermittent resources that are anticipated to come online in the foreseeable future, CAISO is anticipating significant changes in operational needs within its system. Recently, the CAISO illustrated the changing operational needs within its system by plotting the expected normal system hourly load minus the amount of intermittent generation (i.e., the infamous "duck" graph, see Figure 5.2.1). As shown in this figure, commencing in 2015 when significant solar PV generation will come online, the expected system-wide ramping requirement in the evening hours will significantly increase. The CAISO asserts that it needs a significant amount of flexible capacity that can be ramped up and down fairly quickly to assist in managing this supply and demand balance. Also, such flexible capacity must be made available to the CAISO to meet these ramping needs as opposed to utilities using their own resources to meet their individual load requirements.

Currently, FRAC/MOO is proving to be the most potentially cost prohibitive CAISO proposal that Riverside is facing. The FRAC/MOO paradigm is completely changing the way that an LSE's reserve margin is calculated, while concurrently disenfranchising use-limited thermal peaking resources. In late 2013, Riverside was expecting to incur no new resource adequacy (RA) costs under this proposal. Now however, due to the devaluing of our LM6000 peaking units, Riverside is facing potentially significant costs for procuring excess RA to meet the CAISO's new flexible RA mandates.

The FRAC/MOO initiative is continuing with a preliminary market implementation slated for calendar year 2015.

CAISO/CPUC Joint Reliability Framework

Closely related to the FRAC/MOO market initiative is the issue of how the CAISO can incent future flexible capacity to be developed to meet CAISO reliability needs, such as increased ramping and the need to manage over-generation. The CAISO's preferred approach is the centralized capacity market approach, whereby CAISO determines its operational needs a priori and runs a centralized capacity market to procure capacity resources for the long term. However, the CPUC and CAISO are currently working on a compromise market paradigm called the "Joint Reliability Framework" that accomplishes the flexible resource procurement through the local regulatory authorities (CPUC for the IOUs and City Councils for the POUs), while introducing a voluntary centralized capacity market as the backstop. The preliminary details of this hybrid market structure just recently emerged and considerable debate and development still needs to occur before the implementation of this new capacity paradigm takes place.

In the development of this long term hybrid capacity market structure, there are two important issues that will impact Riverside. First is the treatment of imported flexible capacity; for example, will such capacity be treated on the equal footing as in-state flexible capacity? Second, will proper incentives be provided to the utilities to procure non-intermittent renewable resources? The resolution of these issues will have significant financial impacts to Riverside, given our current resources and future resource acquisition plans.

In summary, there are a number of current mandates and initiatives that have the potential to significantly alter RPU's Power Resources costs, primarily in a detrimental manner. How all of these initiatives and mandates play out remains to be seen. Compounding this effect, RPU plans on incorporating 86 MW of new base-load geothermal energy into our resource stack by June 2020. The associated system RA credit we expected to receive for this resource (which is worth millions of dollars per year) is now in doubt. The combined impacts of these various developments may very well force RPU to consider alternative CAISO participation strategies in the near future; e.g., RPU may need to adopt a real-time load following paradigm in order to circumvent potentially egregious future FRAC/MOO RA costs.

14.1.3 Goal 3: Summarize and Access Current EE/DSM Programs

RPU is committed to making Riverside a greener place to live by supporting renewable energy, responsible purchasing and design, and sustainable living practices. An important portion of RPU's future resource strategy is to cost effectively expand our Energy Efficiency (EE) and Demand Side Management (DSM) programs.

Energy Efficiency programs are intended to reduce the total amount of energy used by customers. In general, EE improvements result in our customers using both less energy and less peak demand. Demand Side Management programs, in contrast to Energy Efficiency measures, do not necessarily reduce the total amount of energy used by customers but instead change the timing of energy usage. Typically, DSM programs move energy use from high production cost periods to lower cost periods. DSM programs help to counter or minimize peak demand growth and thereby lessen the need to build more physical generation assets to meet future Resource Adequacy requirements.

Every EE or DSM program carries both costs and benefits to both the customer and utility. In theory, by examining these financial impacts, RPU should be able to identify the optimal mix of EE and DSM programs that maximize the benefits to each customer and minimizes the financial impacts on RPU. However, in order to successfully integrate, analyze and compare EE and/or DSM programs with power supply side options, we need to be able to calculate the total program impact equation for each EE or DSM program of interest. The correct quantification of our unmet retail revenues is absolutely necessary in order to fully assess the impacts of any EE or DSM program.

Additional work needs to be undertaken to better quantify the comprehensive costs and benefits of each EE and DSM program that RPU currently offers. Our Public Benefits Division currently administers our EE and DSM programs and measures our energy efficiency program effectiveness and savings using the CPUC approved E3 Reporting Tool (Energy and Environmental Economics, Inc.). Estimates of the technical, economic and market energy efficiency potential for our utility service area are also produced using Navigant's Energy Efficiency Resource Assessment Model (EERAM). It may be possible to customize either the E3 and/or EERAM tools to accurately estimate our unmet retail revenue streams. As discussed in Chapter 6, we recommend that the Planning Unit coordinate with Public Benefits to investigate this possibility, as well as to determine how to best explicitly integrate RPU's various EE and DSM programs into future Ascend production cost modeling analyses.

Accurate quantification of our avoided or deferred distribution system costs are also very important, especially when considering EE or DSM options for our larger industrial customers. The Energy Delivery Engineering Division is both capable and qualified to perform such calculations. The Power Planning unit intends to closely coordinate with the Engineering Division to obtain such cost estimates, in order to better quantify the avoided distribution system costs for such programs in subsequent follow-up studies. This will be particularly important, given that some of our DSM options may concurrently qualify as effective energy storage options, and as such might be simultaneously used to meet our energy storage mandates.

14.1.4 Goal 4: Examine and Quantify our Intermediate Term Power Resource Forecasts

In Chapter 8 we presented a detailed overview our most critical intermediate term power resource forecasts. This overview quantified the power supply forecasts and metrics that the Planning Unit routinely analyzes, monitors and manages in order to optimize Riverside's position in the CAISO market and minimize our associated load serving costs. More specifically, these metrics included forecasted (a) capacity, system peaks and Resource Adequacy needs, (b) renewable energy resources and projected RPS percentages, (c) primary resource portfolio statistics, (d) internal generation statistics, (e) hedging percentages and open energy positions, (f) unhedged energy costs and cost-at-risk (CAR) statistics, (g) GHG emission profiles and net carbon allocation positions, and (h) five-year forward Power Resource budget estimates. Based on the forecast data presented in Chapter 8, the following primary conclusions can be drawn concerning RPU's intermediate term resource positions.

System Capacity & RA Needs:

As shown in Figure 14.1.1, although RPU will have enough generation capacity to meet our expected monthly system peaks in 2015, we cannot meet the 115% RA requirement during the Q3 summer months. Additionally, although we have contracted for new geothermal capacity in 2016 and 2019 and also extended our Hoover contract past 2017, it is currently unclear if we will be able to obtain RA credit for these resource additions and/or contract extensions. In the absence of such credit, we will not have enough capacity to fully meet our CAISO RA requirements during any Q3 summer months on/after 2016. Under our current pricing assumptions, approximately 6.9 million dollars of additional RA will need to be forward purchased to satisfy this Resource Adequacy mandate.

Additionally, the CAISO is currently implementing a new flexible RA paradigm under its current FRAC/MOO proposal. Under this new paradigm, it is reasonable to expect that our RA costs will be at least as high as RPU's cost under the current RA paradigm, and potentially much higher due to the fact that our LM6000 RERC units may not fully qualify as Category 1 flexible RA resources. This new FRAC/MOO paradigm potentially represents RPU's single greatest financial exposure over the next three-to-five years.

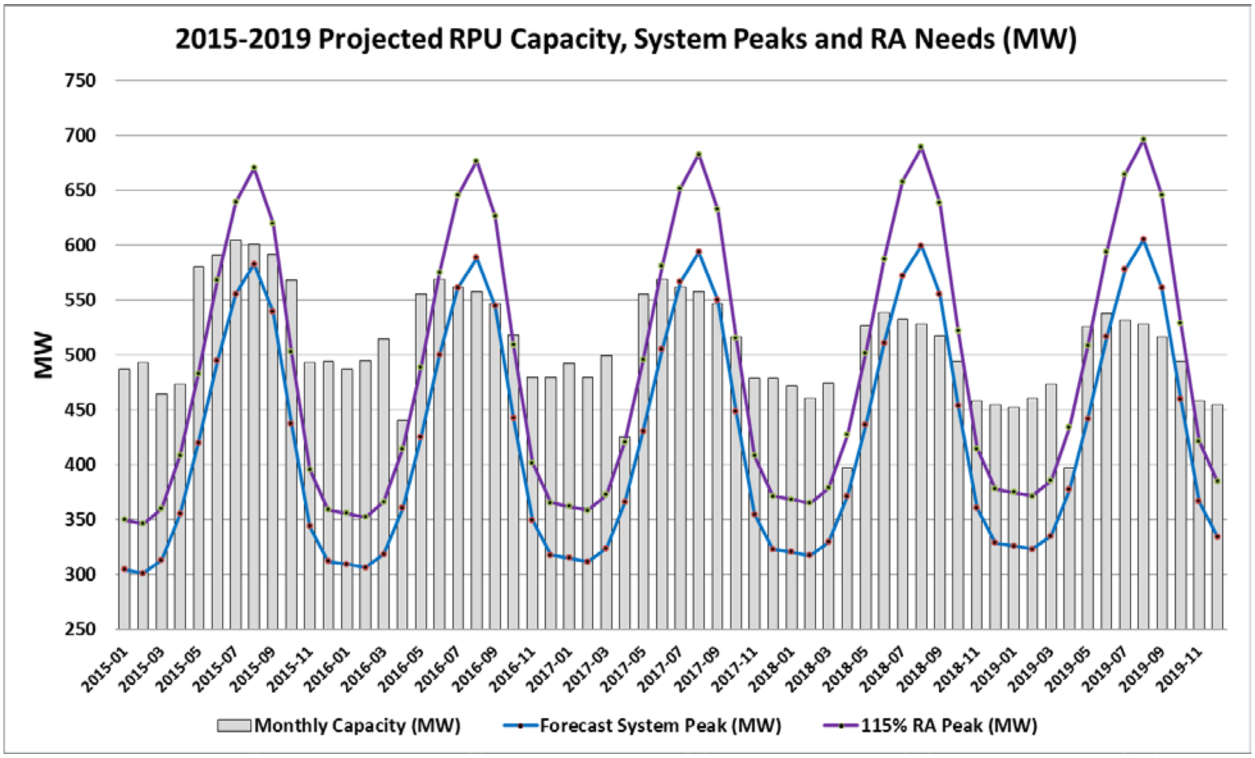


Figure 14.1.1. RPU 5-year forward capacity projections, system peaks and RA needs (2015-2019 timeframe).

Renewable Energy Resources:

RPU is on track to procure an excess amount of renewable energy, above and beyond our minimum mandated amounts. Beginning in early 2016, RPU should exceed our minimum SB-2 25% RPS mandate by about 4%, reaching a 31% RPS in CY 2017 and then a 36% to 37% RPS in CY 2019. All of these new renewable PPAs qualify as Portfolio Content Category 1 products under the SB-2 paradigm and the above mentioned RPS percentages do not include any Category 2 bundled renewable products or Category 3 tradable renewable energy credits (TRECs).

Figure 14.1.2 shows RPU's forecasted monthly RPS levels over the next five years (see also Figure 8.2.1), assuming that all of our new renewable energy contracts come online as expected.

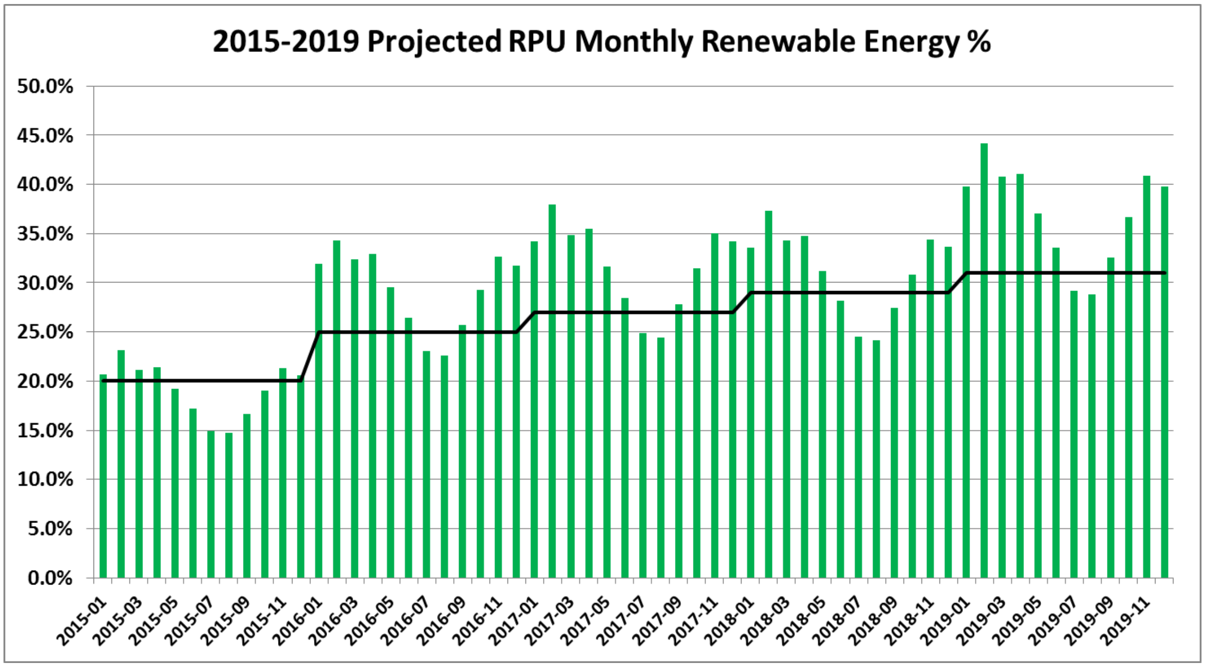


Figure 14.1.2. RPU five year forward renewable energy projections (2015-2019 timeframe).

Resource Portfolio Stack & Forward Hedging Needs:

RPU has about 85% of its load serving needs naturally hedged through long-term PPAs and generation ownership agreements. The remaining 15% of open energy positions need to be actively hedged via forward market purchases of energy and natural gas. As shown in Figure 14.1.3 (see also Figure 8.5.3), most of the remaining open energy volumes are associated with June-Oct heavy load (HL) time periods (particularly Q3 HL), and with Mar-Apr outage events.

RPU's current expected costs to fully close these open HL positions range from 8.9 to 13.7 million dollars annually in the 2015-2019 time period. These annual forecasted costs are itemized in Figure 14.1.4 (see also Figure 8.6.2). The associated cost-at-risk (CAR) metrics for the same time period currently range from 3.9 to 8.2 million dollars, respectively.

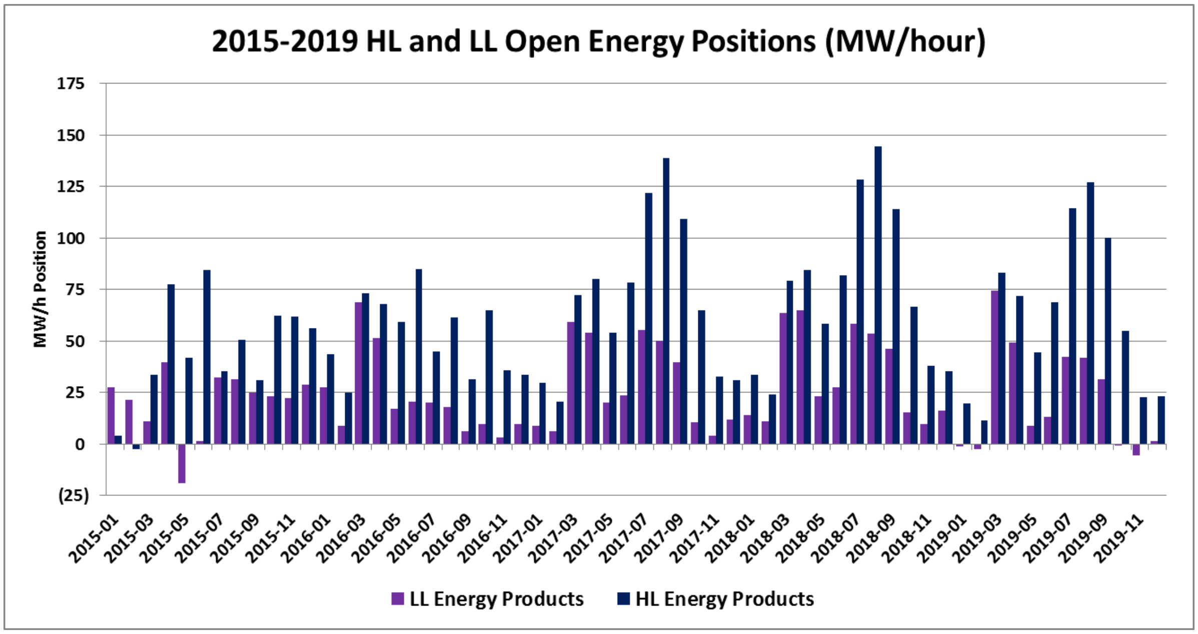


Figure 14.1.3. 2015-2019 NEP forecasted monthly open HL and LL energy positions (MW/hour).

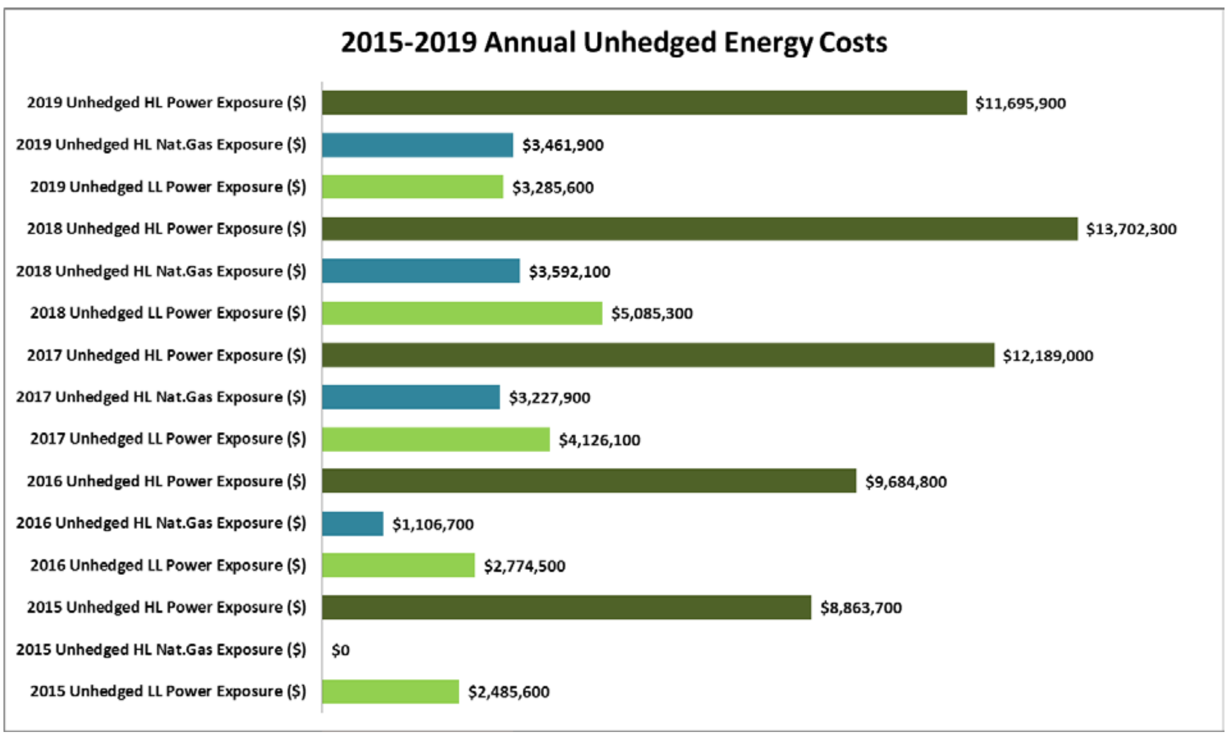


Figure 14.1.4. Forecasted annual HL, LL, and natural gas unhedged energy costs: 2015-2019 timeframe.

Carbon Allowances:

RPU is expected to have more than enough Carbon allowances to fully meet our direct emission compliance needs through 2020. We currently forecast an excess allowance balance of approximately 267,000 to 304,000 credits annually. These are expected to be monetized through the CARB quarterly auction process, with most of the proceeds used to help offset RPU's incremental renewable energy costs. Table 14.1.1 below shows our forecasted proceeds through 2019 for two sets of potential future auction prices.

Table 14.1.1. Expected annual surplus carbon allowance positions and associated revenue streams: 2015-2019 timeframe.

Year	Net Allowance Surplus (MMT)	Auction Floor Price ($/ton)	Revenue Stream (M $)	Projected CO2 Price ($/ton)	Revenue Stream (M $)
2015	0.301	$12.03	3.623	$14.00	4.217
2016	0.280	$12.76	3.580	$15.00	4.208
2017	0.267	$13.52	3.611	$16.00	4.273
2018	0.304	$14.33	4.356	$17.00	5.167
2019	0.300	$15.18	4.550	$18.00	5.395
Total	1.452		19.720		23.260

Five-Year Forward Budget Forecast:

RPU's FY15/16 net portfolio cost is projected to decrease by approximately 3.5 million dollars over the prior year's FY14/15 forecasts; this decrease is primarily due to the SONGS generation facility decommissioning activities. Beyond FY15/16, our overall Power Resource budget costs are currently forecasted to increase by 6 to 10 million dollars per year (through FY19/20), due to the simultaneous impact of rising CAISO transmission, energy and capacity costs.

Overall Summary:

In summary, RPU is reasonably well positioned to meet its load serving needs over the next five years while minimizing the forecasted increase in its internal portfolio costs. RPU's CAISO market costs could be further significantly impacted under the new FRAC/MOO proposal; our staff remains actively engaged in the FRAC/MOO stakeholder process to minimize these RA related cost impacts. With respect to energy needs, some additional systematic forward hedging activities are required to maintain cash flow stability. Additionally, some opportunities still exist for further renewable or thermal resource procurement, specifically during Q3 summer months.

14.1.5 Goal 5: Examine and Analyze Critical Longer Term Power Resource Issues

The bulk of the analytical work presented in this IRP was performed to address this fifth and final goal. Chapters 9 through 13 quantify the various results for the longer term power resource analyses that we have considered.

Chapter 9 outlined RPU's longer term future capacity and renewable energy needs for the 2014-2033 time horizon. Ultimately, these needs will be primarily influenced by our future load growth rates and the termination date of our 136 MW IPP Coal contract. However, our future capacity needs will also be significantly impacted by changes to the CAISO RA paradigm and the type of RA resources that satisfy CAISO's reliability needs in the future. Likewise, our renewable energy needs will depend critically upon future RPS mandates. Chapter 9 examined and quantified each of these various scenarios in greater detail, and defined the scenario framework for the various IRP studies examined in Chapters 10, 11 and 12.

Chapter 10 examined the projected budgetary impacts of twelve different future resource scenarios, which collectively examine the impacts of two load growth scenarios, two RPS mandates and two IPP contract end dates, in conjunction with both unhedged and forward hedged post-IPP market power replacement options. This budgetary assessment considered both the expected values and simulated standard deviations of our fully loaded, forecasted cost of service. The impacts of each fundamental IRP input assumption were examined in detail, specifically with respect to minimizing our expected cost of service over the next twenty year time horizon.

In Chapter 11 we examined five additional generation scenarios that could represent reasonable IPP replacement options, and compared these new scenarios to the forward market hedged scenario examined in Chapter 10. The five alternative replacement options examined in Chapter 11 were as follows:

- a self-build of new internal generation, consisting of either a 100 MW high-efficiency simple, cycle gas plant or approximately 50 MW of internal combustion engines,
- a decision to participate in the IPP Repower Project (50 MW option),
- a decision to replace at least half of the IPP coal energy with a new long term renewable contract, and
- the acquisition of a near-term, 150 MW commercial tolling contract.

As in Chapter 10, our budgetary assessment for each of these alternatives considered both the expected values and simulated standard deviations of our fully loaded, forecasted cost of service.

In Chapter 10 we examined and quantified the costs of reaching and maintaining both a 33% and 40% RPS through 2033 under current renewable pricing assumptions. In Chapter 12 we expanded on this analysis by examining the projected additional portfolio cost impacts associated with RPU adopting a "50% by 2030" RPS mandate. Additionally, we also reexamined the 33%, 40% and 50% mandates under significantly higher pricing assumptions (i.e., current renewable pricing forecasts inflated by 50%). Once again, our budgetary assessment for each of these alternatives considered both the expected values and simulated standard deviations of our fully loaded, forecasted cost of service.

In addition to our IPP replacement decision and RPS strategy, RPU faces a number of additional longer-term resource planning issues that deserve special attention. In Chapter 13 we examined four of these resource planning issues in greater detail: (a) the current value of Energy Storage as a resource asset, (b) the current value of an “ideal” DSM/DR program, (c) the cost/benefit impacts associated with customer installed solar PV systems in the RPU service area, and (d) the potential impacts and benefits associated with electric vehicles. Some recommendations for how RPU should deal with each of these secondary issues were also presented.

Summaries of our analyses and findings with respect to each of these longer term resource planning issues are presented below.

Future Capacity and Renewable Energy Needs

In Chapter 9 we outlined RPU’s longer term future capacity and renewable energy needs; i.e., our projected needs for the next 20 year time horizon. Ultimately, these needs will be primarily influenced by our future load growth rates, potentially higher RPS mandates, the termination date of our 136 MW IPP Coal contract, and the outcome of various modifications to the CAISO RA paradigm. Under the current 33% RPS by 2020 mandate, Riverside will need to procure additional renewable energy resources in the latter part of the 2014-2033 time horizon to remain fully RPS compliant. Likewise, Riverside will certainly need to procure IPP replacement capacity no later than 2027, and potentially much earlier.

As discussed in detail in Chapter 9, the exact timing and amount of new renewable resources will depend upon our future load growth pattern and future changes to the RPS mandate (if any). Thus, we have analyzed three RPS scenarios (“33% through 2030”, “40% by 2030” and “50% by 2030”) in this IRP, in order to gain a better idea of potential future renewable energy requirements and cost of service impacts.

With respect to our future capacity needs, the situation is more complicated. In addition to the uncertain IPP termination date, our future capacity needs will also be significantly impacted by both the future CAISO FRAC/MOO RA paradigm and the amount of RA credits we receive for intertie resources that are not currently grandfathered. The CAISO’s RA paradigm is expected to change over time due to changing grid reliability needs. Therefore, the type of resources needed to maintain grid reliability and count for RA capacity are also likely to change; such changes are already occurring under the FRAC/MOO stakeholder process. Likewise, the CAISO allocates intertie allocation on an annual basis using a peak load ratio share methodology after taking into account all the grandfathered resources an entity already has. However, there is no certainty that RPU will receive intertie allocation credit for newly contracted resources. This uncertainty will impact RPU’s new Salton Sea geothermal resource beginning in February 2016 and our Hoover resource after the current Hoover contract expires in September 2017.

Figure 14.1.5 shows how the loss of this intertie allocation impacts our future capacity and RA needs (see also Figure 9.1.2). RPU's exposure on this issue is considerable; by 2021, the RA value associated with these two contracts is estimated to be 2.7 million dollars; by 2025, this value will exceed 3 million dollars. Over the 2016-2025 time horizon, the combined value of this RA credit is forecasted to be greater than 20 million dollars, respectively.

All this uncertainty will greatly influence and impact our future capacity and renewable resource acquisition decisions, as well as the future operational model that RPU elects in the CAISO markets.

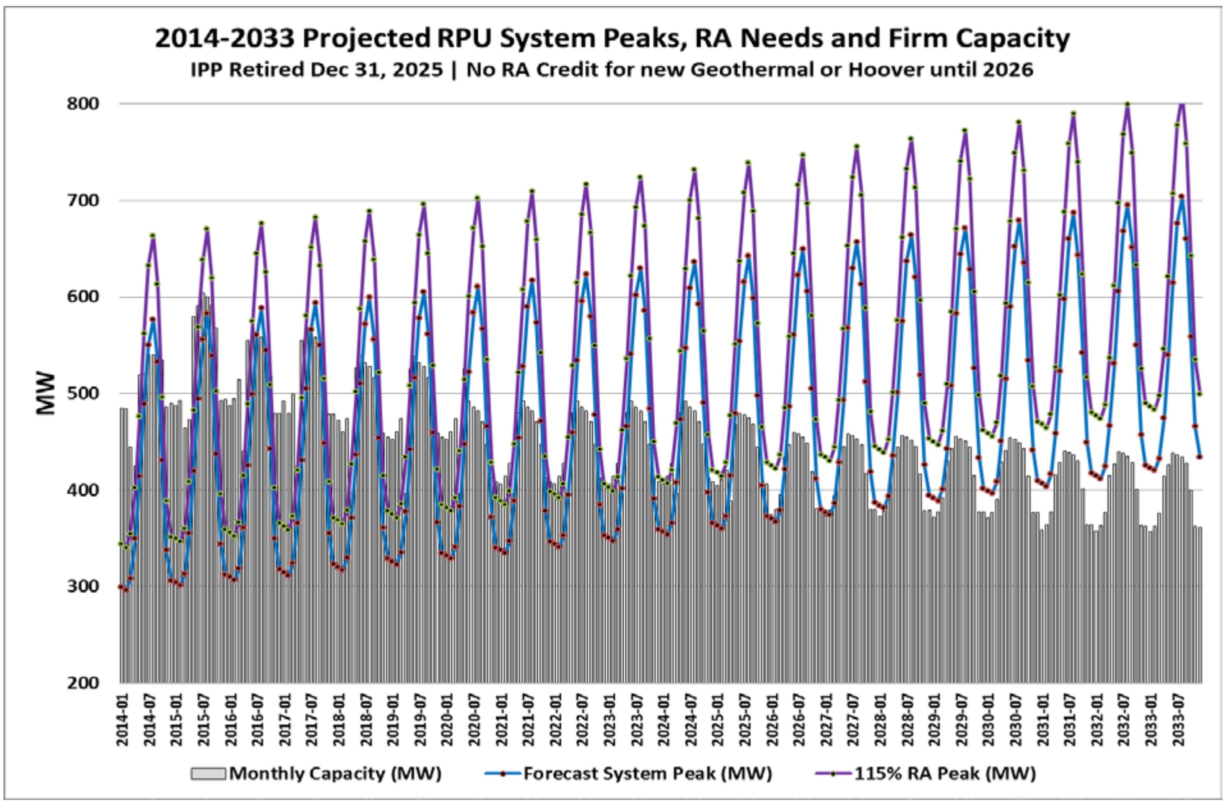


Figure 14.1.5. Projected future capacity shortfall (strong peak growth assumption), assuming the IPP coal plants retire in January 2026 and that RPU receives no RA credit for the Hoover and CalEnergy contract extensions.

Long Term Portfolio Analyses

Modeling Methodology

In Chapter 10 we performed a comprehensive analysis of twelve different future portfolio scenarios based on two potential future load growth patterns, RPS mandates, and IPP contract termination dates, using both unhedged and hedged foreword market purchases to replace our IPP contracts. Each of these scenarios was examined in detail under simulation, specifically with respect to minimizing our expected cost of service over the next twenty year time horizon.

Table 10.1.1 lists the twelve different forward portfolio scenarios that were examined in detail in our phase I long term portfolio studies. One hundred simulation runs were performed for each scenario shown in Table 10.1.1. These simulations allowed us to not only quantify the expected annual load serving costs associated with each portfolio scenario, but also the associated “cost at risk” uncertainty (i.e., standard deviation) surrounding these cost estimates.

More specifically, the corresponding total net portfolio costs (TNPC) were summarized at the annual level for each simulation run and in turn used to compute the expected net portfolio costs and associated standard errors for each scenario. The TNPC variable was defined as

TNPC = TGC + TLC - TGGR - HP(MtM)

where the variables on the right hand side of this equation were defined as:

- TGC: The total generation costs associated with all of the generation assets in the portfolio.
- TLC: The total cost for purchasing our system load (from the CAISO SP15 day-ahead market).
- TGGR: The total gross revenue received from selling all of the generation energy in our RPU portfolio back into the SP15 market.
- HP(MtM): The total payoff amount associated with all of our forward hedging instruments, computed on a mark-to-market basis.

Once determined, the TNPC variable was combined with our primary additional fixed budgetary costs, in order to determine the overall annual load serving costs under each specific scenario.

The following fixed budgetary costs and revenues had to be specified in order to calculate future cost-of-service projections. These secondary costs and revenues were as follows:

- SONGS: The cost obligations associated with winding down our SONGS contract and initializing the decommissioning process.
- CAISO Transmission costs: Our transmission costs, as determined by future CAISO Transmission Access Charge rates.
- GHG/Carbon revenues: The revenues associated with the sale of carbon emission credits, and the assumptions concerning the number of free allowances (if any) beyond 2020.

- Resource Adequacy (RA) costs: The cost assumptions surrounding our future RA purchases needed to satisfy the 115% CAISO RA paradigm.
- CAISO Uplift fees and other Power Resource costs: The ongoing costs associated with our CAISO energy and transmission uplift fees, CRR auction expenses, and internal generation facilities.
- Utility Personnel and O&M costs: RPU's "all-other" operational costs, not related to power supply activities.
- Long-term Debt Service costs: RPU's long-term Debt Service costs.
- General Fund Transfer Fee: RPU's obligation to transfer 11.5% of its gross annual revenues to the City of Riverside.

Note that while a few of these costs were common across all of our simulated IRP scenarios (e.g., SONGs, Personnel and O&M, and Debt Service), most of these costs (and the GHG/Carbon revenues) were a function of one or more of the IRP input variables.

Once these additional budgetary costs had been estimated, we calculated our total net cost of service (NCOS) before the GFT as the TNPC, plus the sum of all of the additional budgetary costs, minus any revenue from the sale of carbon allowances; i.e.,

$$\text{NCOS} = \text{TNPC} + \text{SONGS} + \text{TAC} + \text{RA} + \text{UFOC} + \text{AO} - \text{GHG}$$

These remaining variables represented our additional costs associated with SONGS, our CAISO Transmission Access Charge (TAC), system RA needs (RA), CAISO uplift fees and other Power Resource costs (UFOC), our all-other (AO) utility costs, including our long-term debt service requirements, and our GHG allowance revenues (GHG), if any. Once the net COS was determined, we then divide this by the additional GFT ratio to produce a gross cost of service (GCOS) estimate; i.e.,

$$\text{GCOS} = \text{NCOS} / 0.885$$

where the 0.885 division factor was used to calculate the additional revenue that must be obtained in order for our total revenues to be in balance with our total GCOS.

Finally, we produced a "load normalized" GCOS metric, since this essentially corresponds to the future average retail rate that RPU must charge to fully recover all of its expected costs. This load normalized metric (COS_{LN}) was defined as

$$COS_{LN} = \text{GCOS} / \text{Retail.Load}$$

where the retail load was set equal to 95% of our total (strong or weak) system load forecasts, respectively.

These COS_{LN} estimates (and associated uncertainty estimates) were used to facilitate an effective comparison between the different IRP scenarios, and to determine the degree to which each primary input variable influenced the COS_{LN} metric.

Summary and Results

The panel graph shown in Figure 14.1.6 (see also Figure 10.1) shows the expected, load normalized cost of service (COS_{LN}) estimates in 2023 and 2033 for the twelve resource planning scenarios examined in Chapter 10. Note that the twelve scenarios have been ordered by their 2023 COS_{LN} estimates, from high to low. (For reference purposes, RPU's current COS_{LN} is approximately 13.7 ₵/kWh.) In addition to each estimate (shown as black diamonds), two standard deviations of uncertainty are also shown (blue and green vertical bars, respectively); these bars define the range of uncertainty associated with each COS_{LN} estimate. As shown in this figure, our long term load growth projections represent the single greatest driver of our ultimate cost of service, while our hedging strategy represents the primary factor influencing the associated COS_{LN} uncertainty estimates.

The panel graph shown in Figure 14.1.7 (see also Figure 10.2, Table 10.7.1, and Table 10.7.2) further quantifies and summarizes the Chapter 10 scenario simulation results. The upper panel plot shows how much each studied factor adds to our baseline COS_{LN} costs in 2023, 2028 and 2033, while the lower panel plot quantifies the corresponding uncertainty effects (standard deviations) associated with these same factors. As shown in the upper panel plot, if RPU were to experience weak load growth over the next ten to twenty years, we should expect our COS_{LN} to increase by 1 to 2 ₵/kWh over this same time horizon. This is by far the single greatest influencing factor in determining our future COS_{LN} estimates; note the next largest impact is associated with an early IPP termination date (~ 0.5 ₵/kWh impact). In contrast, achieving a 40% RPS and/or replacing IPP energy with hedged market purchases add relatively little to our forecasted future COS_{LN} estimates. Similar information is summarized in the lower panel plot, but here with respect to the associated COS_{LN} uncertainty estimates. Note that while adopting a viable hedging paradigm adds little to our expected COS_{LN}, it greatly reduces the associated uncertainty around these estimates. The 40% RPS scenario also slightly reduces our COS_{LN} uncertainty estimates (as does weak load growth), although both of these impacts are relatively minor.

Based on the results discussed in sections 10.3 through 10.6, the following conclusions can be drawn with regards to our future cost of service forecasts and associated portfolio risk projections.

- As made clear from the results shown in section 10.3 and Table 10.7.1, our assumed future load growth rate significantly impacts our future cost-of-service forecasts. Our COS_{LN} forecasts are 10% higher in 2028 and 13% higher in 2033 under a weak load growth assumption, as compared to the strong (healthy) assumption. In general, RPU has already reached a tipping point where our "all other" costs are growing much faster than our service area load level. Thus, reductions in our load growth rate will most likely translate into direct cost of service increases, unless the unrealized, avoided loads are highly strategic in nature.

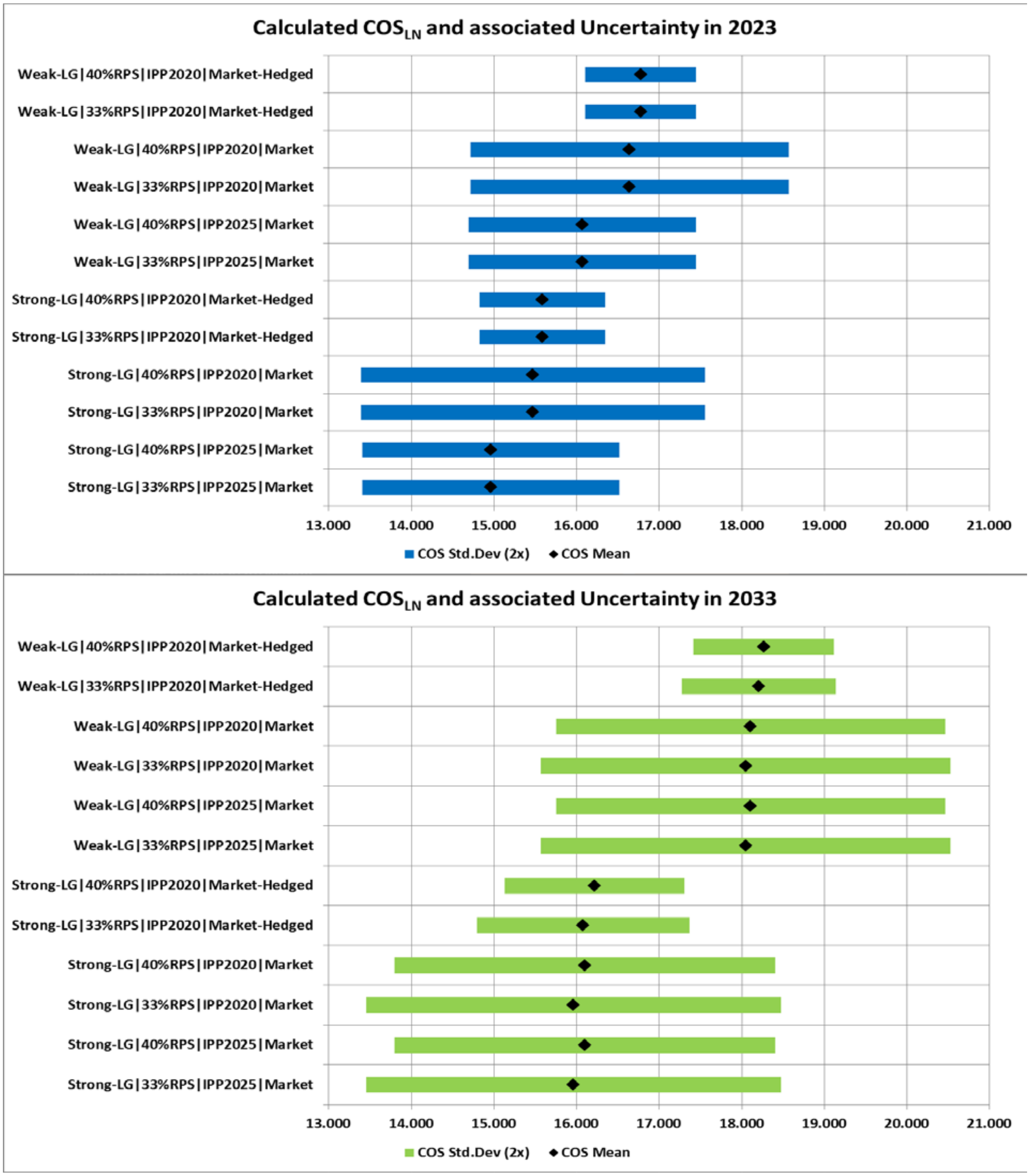


Figure 14.1.6. Panel plots of forecasted COS_{LN} and associated uncertainty (± 2 standard deviations) in 2023 (upper plot) and 2033 (lower plot) for the Chapter 10 scenario studies.

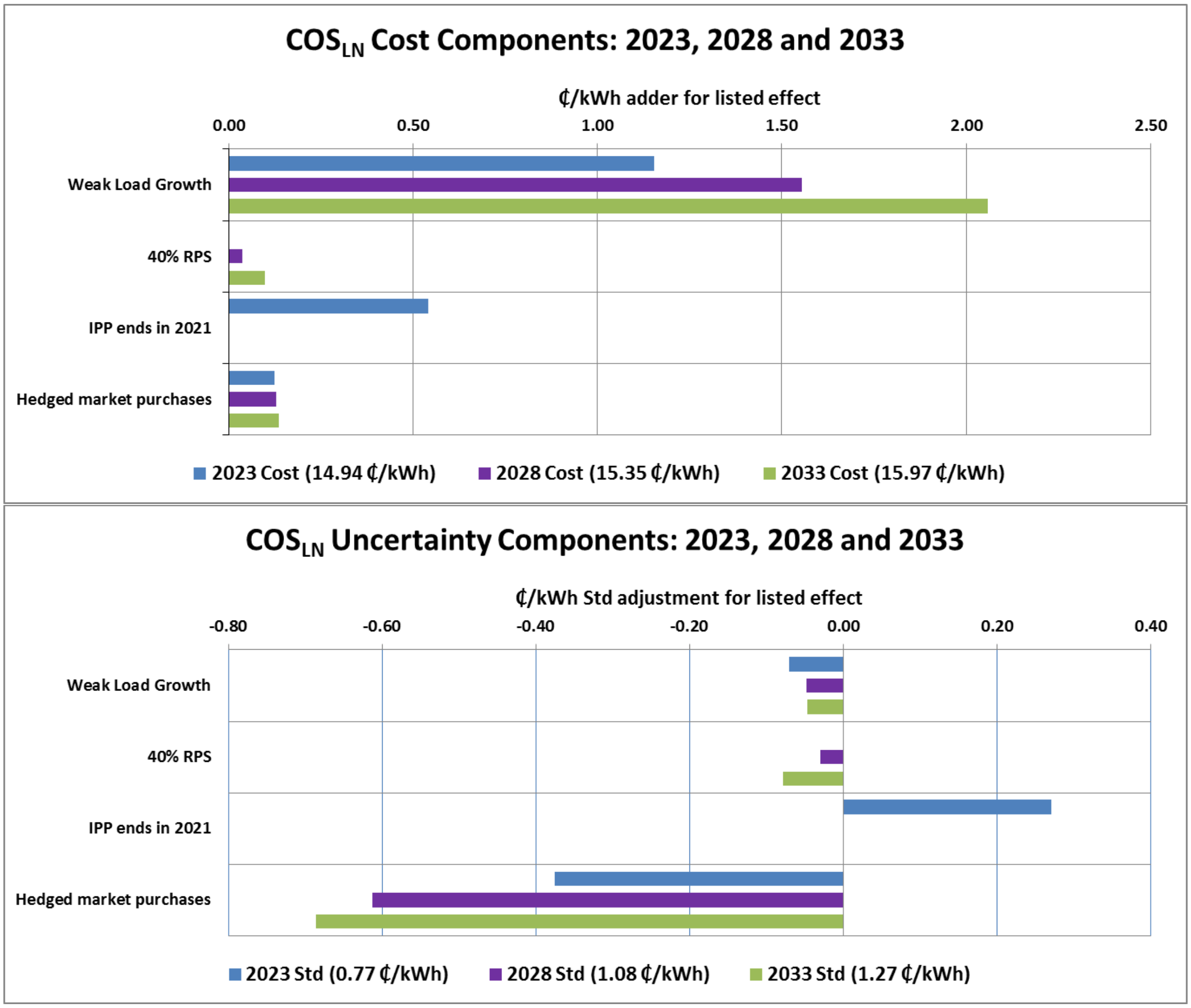


Figure 14.1.7. Panel plots of the calculated COS$_{LN}$ components (expected costs and associated standard deviations) for the four primary input factors; estimates shown for years 2023, 2028 and 2033.

- In contrast to the load growth impact discussed above, we project that RPU can reach and maintain a 40% RPS mandate with relatively minimal rate impacts (i.e., < 1%), at least under the pricing assumptions considered in Chapter 10. Contract prices for renewable energy generation have fallen significantly in the last few years; a number of renewable contracts can now be obtained in the $65/MWh to $80/MWh price range. Given that the "all-in" thermal energy generation costs are around $60/MWh in our current portfolio, the purchase or contracting of additional renewable energy assets certainly represents one viable future procurement strategy, assuming that their pricing structure remains attractive and that the corresponding energy can be effectively used to hedge our load serving needs.

- As discussed in sections 10.3 and 10.4, the timing of our IPP contract termination date will also significantly impact our future cost of service. We currently project a 0.5 ₵/kWh to 0.6 ₵/kWh cost increase associated with an early, non-voluntary IPP contract termination event. Additionally, we currently project a 1.0 ₵/kWh to 1.1 ₵/kWh cost increase due to the loss of free Carbon emission credits on/after 2021.

- From a strictly economic perspective, it does not make sense to try and unilaterally terminate our IPP contract any earlier than necessary. Rather, we should continue to support a market driven dispatch scheme that recognizes the inherent Carbon cost embedded in this energy asset, while searching for a replacement option that can come online within the 2021-2026 time-frame. It should be noted that this strategy could change in the future, should Carbon emission costs rise significantly above their current long-term forecasted levels. However, under a high emission cost scenario, a market driven dispatch approach will naturally ramp down our IPP energy anyway, so there is little downside risk to continuing to employ this type of generation strategy for the time being.

- Finally, as demonstrated by the analysis of the section 10.6 price shock studies, our IPP energy will need to be replaced with some type of fixed price generation asset or long-term, forward hedged energy contract(s), if we wish to contain our future portfolio risk at an acceptable level. From a risk perspective, RPU cannot afford to leave such a large base-load energy position open and exposed to significant SP15 day-ahead market price movements; the resulting cash-flow uncertainty will simply be too severe.

It should be noted that in these Chapter 10 studies, the forward market hedged scenarios for either the 33% or 40% RPS mandates clearly produced the lowest composite cost of service estimates, and thus would be preferred under a "least cost, best fit" paradigm.

Alternative Portfolio Analyses: Part I – Additional IPP Replacement Options

Modeling Methodology

In Chapter 11 we examined five alternative generation replacement scenarios that could represent reasonable IPP replacement options, and compared these new scenarios to a market hedged scenario. The five alternative replacement options examined in Chapter 11 were as follows: (A1) new internal generation: a 100 MW GE LMS-100 high-efficiency, simple cycle gas plant, (A2) new internal generation: five 9.3 MW Wartsila 20V34SG simple cycle internal combustion units, stacked together into a 46.5 MW generation facility, (B) a decision to participate in and purchase 50 MW of the 1,000 MW IPP Repower Project, (C) replacing 75 MW of the IPP coal energy with a new long term renewable contract, and (D) the acquisition of a near-term 150 MW commercial tolling contract (beginning in January 2016). A high-level description of each alternative is shown in Table 14.1.2 (see also Tables 11.1.1 and 11.1.2).

As in our previous analyses, 100 simulation runs were performed for each alternative scenario. These simulations allowed us to quantify both the expected annual load serving costs and the associated uncertainty (i.e., standard deviation) surrounding these cost estimates. Likewise, these simulation runs were performed at the hourly granularity over the same twenty year timeframe (January 1, 2014 through December 31, 2033), using the same set of input forward price curves. Finally, all of the additional, fixed costs discussed in sections 10.2.1 through 10.2.8 were also applied to these alternative scenarios, in order to facilitate a consistent set of comparisons.

Table 14.1.2. Baseline and alternative IPP replacement options considered in Chapter 11.

Scenario	Description	Additional Notes
Baseline	150 MW of forward hedged, market power contracts	see Section 10.1
Alternative A1	New Internal Generation: 100 MW GE LMS-100 High-efficiency simple cycle gas plant, 7,815 HR, dispatchable from 0 to 100 MW	Includes a 50% long-term forward fuel hedge, + a long-term 50 MW forward power hedge
Alternative A2	New Internal Generation: 46.5 MW Wartsila 20V34SG simple cycle internal combustion unit, 8,308 HR, dispatchable from 0 to 46.5 MW	Includes a 50% long-term forward fuel hedge, + a long term 103.5 MW forward power hedge
Alternative B	Participate in IPP Repower Project: 50 MW of NGCC: 7,000 HR, dispatchable from 20 to 50 MW	Includes a 75% long-term forward fuel hedge, + a long-term 100 MW forward power hedge
Alternative C	New 75 MW base-load Renewable Energy contract (PPA)	Also includes a long-term 75 MW forward power hedge
Alternative D	150 MW Tolling Contract, beginning on January 1, 2016	Includes a 92% long-term forward fuel hedge upon IPP retirement

Summary and Results

The panel graph shown in Figure 14.1.8 (see also Figure 11.2) shows the expected, load normalized cost of service (COS_{LN}) estimates in 2023 and 2033 for both the baseline and five IPP replacement scenarios examined in Chapter 11. These six scenarios have been ordered by their 2023 COS_{LN} estimates (from high to low). In addition to each estimate (shown as black diamonds), two standard deviations of uncertainty are also shown (blue and green vertical bars, respectively); these bars define the range of uncertainty associated with each COS_{LN} estimate. As compared to the baseline scenario, four of the five IPP replacement scenarios result in an increased cost of service, and all five replacement scenarios result in higher associated COS_{LN} uncertainty estimates. Thus, with respect to a risk minimized COS_{LN} criteria, none of the alternatives considered here outperform the baseline option of using forward hedged, market power contracts to replace our IPP contract.

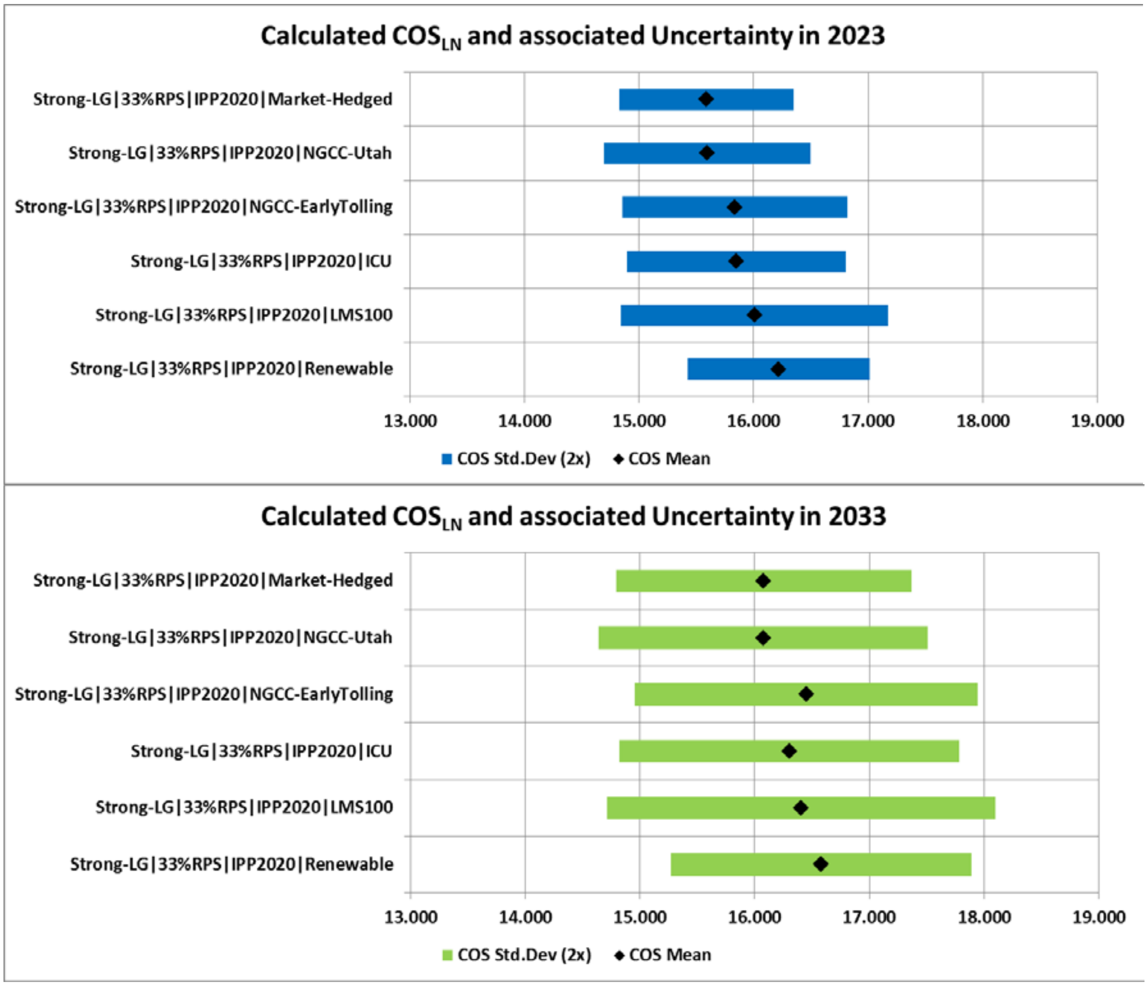


Figure 14.1.8. Panel plots of forecasted COS_{LN} and associated uncertainty (± 2 standard deviations) in 2023 (upper plot) and 2033 (lower plot), for the six IPP contract replacement options examined in Chapter 11.

The results presented in Chapter 11 are preliminary and subject to further refinements and confirmation of costs. More specifically, the following issues and caveats (discussed in greater detail in section 11.4) should be recognized:

1. With respect to building new internal generation, it is currently difficult to accurately estimate either the final cost of our emission offset credits or the magnitude of our "all-other" owner

capital costs for many of the alternatives considered in Chapter 11. Additionally, these uncertainties are not currently reflected in the COS_{LN} risk components.

2. Important secondary benefits associated with new internal generation (such as improved system reliability or increased MSS load-following capabilities) were not quantified and analyzed in these preliminary analyses.

3. The engineering, design, and construction (EDC) cost estimates associated specifically with the IPP Repower Project scenario are also very preliminary and uncertain. In reality, Riverside would have little control over these actual costs; RPU would be dependent upon IPA to control the EDC process.

4. Although the base-load renewable option represented the most well defined alternative, at least with respect to minimal unknown costs, we have yet to identify an appropriate base-load renewable resource within the state of California that can meet our power replacement needs at a reasonable price.

Notwithstanding these modeling issues and uncertainties, some additional preliminary conclusions could still be drawn from the Chapter 11 analyses, which are summarized below.

- The Repower Project scenario represented the most cost-effective alternative option analyzed in Chapter 11, although not by a wide margin. Given this result, RPU should remain engaged in the Repower Project discussions and preserve this alternative as a future option for replacing our IPP contract (assuming that these discussions continue).

- The value associated with the additional benefits that new internal generation might offer RPU need to be better understood and quantified, in order to perform a more meaningful comparison between alternatives. Additional studies should be performed in the future, given that some of these potential benefits are dependent upon future CAISO market paradigms and/or the development schedule of the Riverside Transmission Reliability Project.

- It is not unreasonable to consider replacing at least some of the expiring IPP energy with base-load renewable resources if the increased cost can be justified to and accepted by RPU's customers. To implement this scenario, the key considerations will be technology and geographic diversification. In order for this alternative to be sensible, competitively priced landfill gas or biomass renewable resources in the CAISO footprint might be considered, developed or procured under PPAs. The existing QFs that are expected to expire in the coming years with the IOUs may constitute the primary pool of resources in this category.

- Finally, the early tolling option does not appear to represent a viable alternative at this time, given the current (considerable) uncertainty surrounding the IPP contract end-date and the associated cost uncertainty for post-2020 Carbon allowances.

In summary, four of the five IPP replacement alternatives presented in Chapter 11 may have merit, but each of these alternatives requires further refinement and study. Hence, additional follow-up studies are warranted and should be performed as new information becomes available. However, since none of the alternatives considered here outperform the baseline option of using forward hedged, market power contracts to replace our IPP contract, this baseline option currently represents our preferred IPP power replacement solution.

Alternative Portfolio Analyses: Part II – A Higher RPS Mandate

In addition to our IPP replacement decision, RPU faces the possibility that California may elect to increase the 33% RPS mandate after 2020. Likewise, RPU may voluntarily decide to pursue a higher internal RPS mandate in order to reduce our carbon footprint and reliance on fossil fuel resources. Under either scenario, it is critically important to quantify the cost impacts associated with higher RPS mandates, specifically how such mandates impact our COS_{LN} metric (and associated COS_{LN} risk profile).

In Chapter 10 we examined and quantified the costs of reaching and maintaining both a 33% and 40% RPS through 2033 under our current renewable pricing assumptions. In Chapter 12 we expanded on these analyses by examining the projected additional portfolio cost impacts associated with RPU adopting a “50% by 2030” RPS mandate. Additionally, we also reexamine the 33%, 40% and 50% mandates under significantly higher pricing assumptions (i.e., current pricing forecasts inflated by 50%). As in Chapters 10 and 11, a 20-year forward dispatch simulation analysis was used to calculate and quantify all of our expected portfolio cost impacts, and these impacts were formally summarized via the COS_{LN} metric.

Summary of Results

The panel graph shown in Figure 14.1.9 (see also Figure 12.1) shows the expected, load normalized cost of service (COS_{LN}) estimates in 2028 and 2033 for the six renewable energy scenarios examined in Chapter 12 (i.e., three RPS mandates using two renewable energy price curves). These six scenarios have been ordered by their 2033 COS_{LN} estimates (from high to low). In addition to each estimate (shown as black diamonds), two standard deviations of uncertainty are also shown (purple and green vertical bars, respectively); these bars define the range of uncertainty associated with each COS_{LN} estimate. It is clear from these results that the change in the renewable energy pricing assumptions has a greater impact on the cost of service estimates, as opposed to the RPS target levels. Additionally, this impact becomes more pronounced over time.

A second important result is that as the RPS target levels increase, the associated COS_{LN} uncertainty estimates decrease, because the additional fixed price renewable PPAs provide for more market price certainty. (Note also that this result is independent of the underlying pricing assumptions.) Thus, higher RPS mandates can be justified with respect to a risk minimized COS_{LN} criteria, provided that the pricing of future renewable energy projects remains competitive (i.e., consistent with our current baseline price forecasts).

As discussed previously in Chapter 10, RPU is currently on-track to reach a 37% RPS level by 2019 (and stay above the 33% RPS mandate at least through 2023), after accounting for the renewable energy PPAs that we have already contracted for. Hence, achieving the "40% by 2030" mandate is well within our reach, provided that our current contracts come to fruition and are strategically supplemented with cost-competitive future renewable energy resources. Under the current renewable energy pricing scenarios, the rate impact of such a strategy should be minimal – provided that the CAISO does not impose significant secondary renewable energy integration costs on the load serving entities within its balancing authority area.

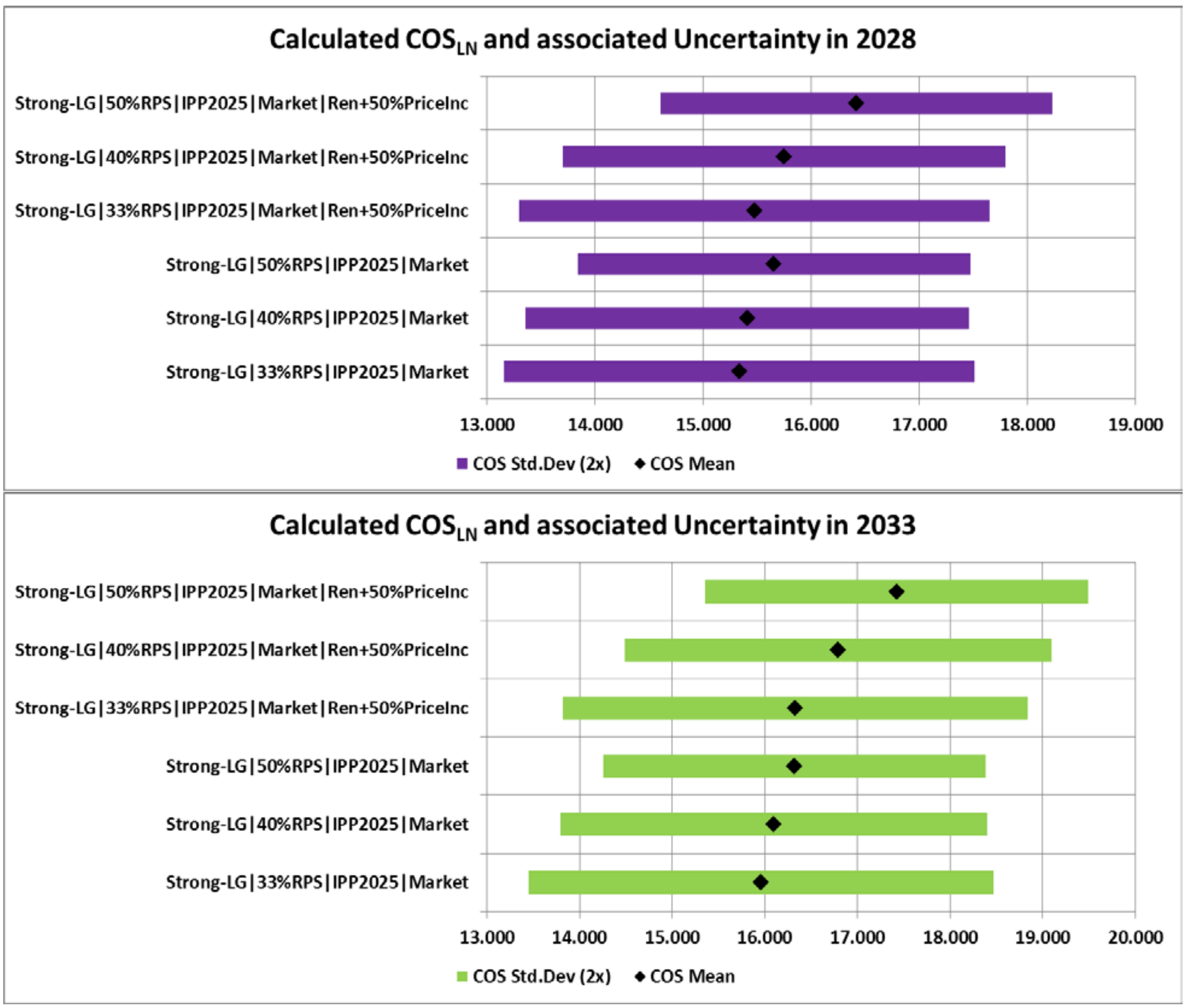


Figure 14.1.9. Panel plots of forecasted COS_{LN} and associated uncertainty (± 2 standard deviations) in 2028 (upper plot) and 2033 (lower plot), for the six future renewable energy scenarios examined in Chapter 12.

This latter point is worth elaborating on. Currently, there are a number of CAISO sponsored initiatives and stake-holder processes directed (either in whole or in part) towards optimally integrating variable (renewable) energy resources into the California grid. The Flexible Resource Adequacy and Enhanced Must Offer Obligation (FRAC/MOO), Energy Imbalance Market (EIM), and Joint Reliability Framework (JRF) initiatives are all designed to address the integration of variable energy resources (see section 5.2). Once implemented, each of these new paradigms may impose significant new costs to CAISO load serving entities. As such, the costs associated with reaching and maintaining higher RPS mandates could become significantly higher than our baseline projections.

Furthermore, it may still only be a matter of time before the state legislature revisits the 33% RPS mandate and imposes new and more stringent, post-2020 renewable energy targets. Additionally, should the state-wide, post-2020 RPS mandate increase, one would naturally expect that market renewable prices to also increase. In turn, this would result in increased energy cost impacts to RPU's portfolio (i.e., higher than the baseline cost forecasts presented here).

Taken together, all of these issues suggest that RPU would be wise to continue increasing the number of renewable energy assets in its portfolio, but also to do so in a very thoughtful and strategic manner. For example, given the numerous problems (and potential costs) associated with integrating variable energy resources into the grid, a preference towards acquiring either base-load or dispatchable renewable resources would seem to be justified. In contrast, contracting for a significant amount of additional solar PV resources is probably unwise right now, given the increasing uncertainty about how the net-load "duck-curve" effect might impact the CAISO market (see section 5.2.3). Instead, contracting for a seasonally-structured energy product where a third party "firms-up" the delivery amount of a variable energy resource could be highly advantageous, and should at least be considered. Finally, it seems logical that RPU should pursue future contracts for renewable energy assets that incorporate (or retain the option to incorporate) energy storage technology. Ideally, such contracts would give us the optionality to develop some form of energy storage option at a later date (e.g., after the costs associated with the storage technology have hopefully decreased).

In summary, we believe that it would be wise to opportunistically work towards reaching a 40% RPS level by 2020. However, RPU will also need to be very strategic about how it continues to work toward acquiring and incorporating a greater percentage of renewable energy assets into its resource portfolio. Although some of the cost pressures discussed above may turn out to be unavoidable, others can hopefully be minimized via the diligent application of intelligent planning activities and reasonable foresight.

Important Secondary Resource Planning Issues

In addition to our IPP replacement and RPS target decisions, RPU faces a number of additional longer-term resource planning issues that deserve additional attention. In Chapter 13 we examined four of these resource planning issues in greater detail: (a) the value of a "generic" Energy Storage system, (b) the value of an "ideal" DSM/DR program, (c) the cost/benefit impacts associated with customer installed solar PV systems in the RPU service area, and (d) the potential benefits and impacts associated with electric vehicles. The first three of these topics represent pressing current issues for RPU; concise summaries of each topic are described below.

Energy Storage

In Chapter 13, we quantified the potential financial benefits of energy storage systems in the RPU service territory. We first specified a hypothetical, generic energy storage (ES) system with a pre-determined charging and discharging interval in our production cost modeling environment, and then dispatched this system under a full set of market simulations. The implied revenue stream of this generic ES system was then computed by combining the appropriately calculated peak versus off-peak energy revenue streams with the avoided RA costs. These results were then further extended to also produce approximate value estimates for a dynamic system, by making some very high-level simplifying assumptions concerning the expected value of the ancillary service revenue stream.

The final product from this analysis was a set of $/kW value curves for generic ES systems with different useful life expectancies and energy charge-to-discharge efficiency factors, as shown in Figure 14.1.10 below (see also Figure 13.2.1). Based on this analysis, we found that a 20-year, dynamically dispatchable ES system has a NPV of approximately $1,100 to $2,200 per installed kW of capacity, depending upon its energy efficiency level. The equivalent 10-year system has a NPV of about $600 to $1,125 per installed kW of capacity. Likewise, for the range of energy efficiency levels considered here, a 20-year passive ES system has a NPV of approximately $450 to $1150, and a 10-year system has a NPV of approximately $250 to $600, respectively.

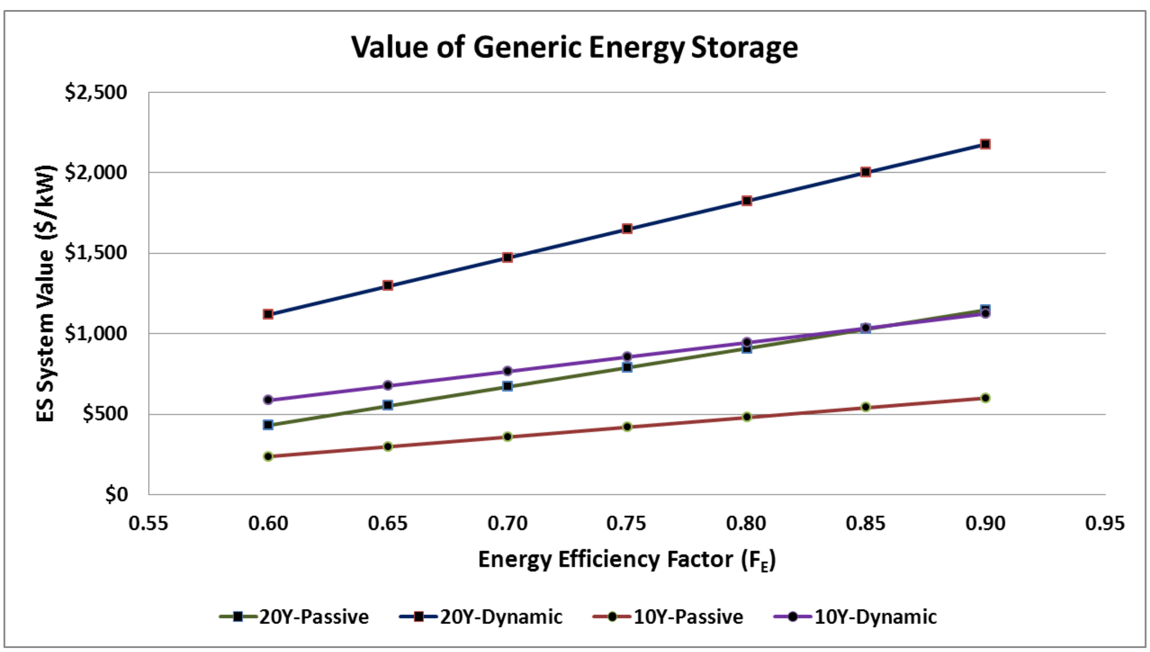


Figure 14.1.10. Forecasted NPV relationships for generic passive and dynamic energy storage systems, for an assumed FAS ratio of 0.5 and an annual discount rate of 3%.

An Ideal DSM/DR Program

In Chapter 13 we also calculated the potential value for an “ideal” Demand Side Management / Demand Response program. In this analysis, the term “ideal” implied that the adopted DSM/DR program would reduce our summer peak energy needs by up to 5%, but without reducing any of our volumetric energy sales. Conceptually, such a program would “smooth out” and reduce our projected 1-in-2 summer peaking needs, without impacting our retail revenue stream. The following input assumptions were used to model our hypothetical DSM/DR program:

- Peak load reductions occur during June through October. In June and October, RPU system peak loads are reduced by 2.5%; in Q3 (July – September), peak loads are reduced by 5%.
- There are no corresponding loss in energy sales, or changes in customer demand charges (i.e., retail sales revenues are unaffected by the DSM/DR program).
- Savings in system energy costs occur due to load smoothing (and shifting); i.e., less load purchased during the highest priced hours in the CAISO day-ahead market, and proportionately more load purchased during lower priced hours.
- ALL RA savings are valued at a blended RA price (see Table 6.6.1), where the RA pricing escalates at 3% annually.
- The DSM/DR program begins in 2016, achieves full enrollment that same year, and continues through 2033.

Based on the above set of assumptions, we found that our 2016 monthly capacity reductions ranged from 10,500 (Oct) to 27,900 (Aug) kW, with a corresponding annual savings of 102,600 kW. By 2033, these monthly capacity reductions range from 13,200 (Oct) to 33,300 (Aug) kW, with a corresponding annual savings of 124,400 kW. Note that these capacity reductions resulted in approximately $300,000 (2016) to $600,000 (2033) in system energy savings, in addition to RA savings.

Upon dividing the annual energy and RA capacity cost savings by the associated annual capacity reductions, we derive the $/kW value of the program. In 2016, the maximum plausible savings potential for such a program is forecasted to be $8.02/kW; by 2033 this value increases to $13.06/kW. Approximately 63% of this savings is associated with avoided RA costs; the remaining 37% can be attributed to system load cost savings. Note that these components were found to be fairly stable throughout the simulation time horizon.

Customer Solar PV

It has become increasingly important to calculate and forecast the financial impacts to RPU resulting from the installation of customer owned solar PV systems in our service territory. We performed such an analysis in Chapter 13, in order to quantify the partial unmet revenue effect associated with our net energy metering (NEM) contracts (using the same criteria discussed in section 6.5 and 6.6.) The goal of this analysis was to determine the partial net program impact ($/kW basis) and the corresponding “solar subsidy” (if any), based on the difference between our unmet retail revenues and our avoided power supply and capacity expansion costs.

Based on an analysis of our avoided costs and unmet revenues, we calculated that the kW normalized, partial net unmet revenue effect for residential solar PV systems in 2014 was $154.64 per kW of installed capacity. Additionally, this unmet revenue forecast is expected to grow over time, eventually reaching $236.57 per kW in 2023.

Unfortunately, the cumulative net unmet revenue stream is also expected to increases significantly over time. Figure 14.1.11 shows the forecasted additional annual costs that our typical non-solar customer must pay RPU to support our current NEM program (i.e., for a typical customer who uses 1,000 kWh of electricity a month; see also Figure 13.4.4). This cost was forecasted to be about $10.70/year in 2014, and should increase to almost $36/year by 2023, if current installation trends continue as expected.

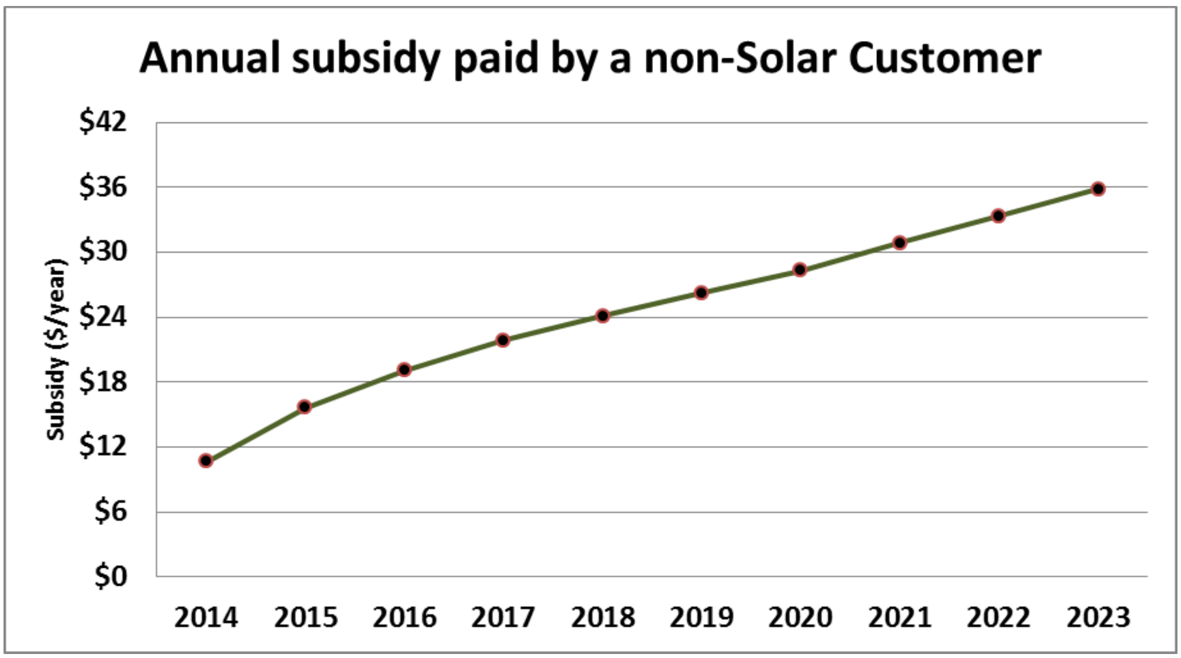


Figure 14.1.11. Forecasted additional annual cost that a typical RPU non-solar customer must pay to support the current NEM program (i.e., for a typical customer who uses 1,000 kWh of electricity a month).

Electric Vehicles

In 2012, California Governor Jerry Brown set a state target of getting 1.5 million zero-emission vehicles on California roads by 2025. This aggressive goal is being pursued by California due to the potential for EVs to dramatically reshape the way in which electricity is stored, managed and regulated on the electrical grid. Thus, the last issue we examined in Chapter 13 was the projected impacts and potential benefits of significant electric vehicle penetration to the California grid.

This being said, the City of Riverside has seen very minimal EV penetration in its service territory to date. Between January 2008 and August 2013, RPU had paid out utility rebates for just 87 EVs (and 55 hybrids). Additionally, in September 2013, RPU launched a new Domestic TOU rate designed for households with electric vehicles. However, as of May 2014, only three customers had signed up for this rate structure. Therefore, RPU has adopted a “wait-and-see” strategy for how to best leverage any future vehicle-to-grid potential in our service territory. Although the state is aggressively pushing the adoption of this technology, there is grossly insufficient EV penetration in our territory to justify any significant infrastructure investments at this time. If/when this trend changes (i.e., improves), RPU will revisit this issue.

14.2 An Optimal Future Portfolio Configuration (Risk-integrated Basis)

Recall that in Chapter 10 we examined the projected budgetary impacts of twelve different future resource scenarios, which were based on two load growth scenarios, two RPS mandates and two IPP contract end dates, in conjunction with both unhedged and forward hedged post-IPP market power replacement options. Next, in Chapter 11 we examined five additional generation scenarios that could represent reasonable IPP replacement options, and compared these new scenarios to the forward market hedged scenario examined in Chapter 10. Finally, in Chapter 12 we examined the projected additional portfolio cost impacts associated with RPU adopting a “50% by 2030” RPS mandate, and also reexamined the 33%, 40% and 50% mandates under significantly higher pricing assumptions (i.e., current pricing forecasts inflated by 50%).

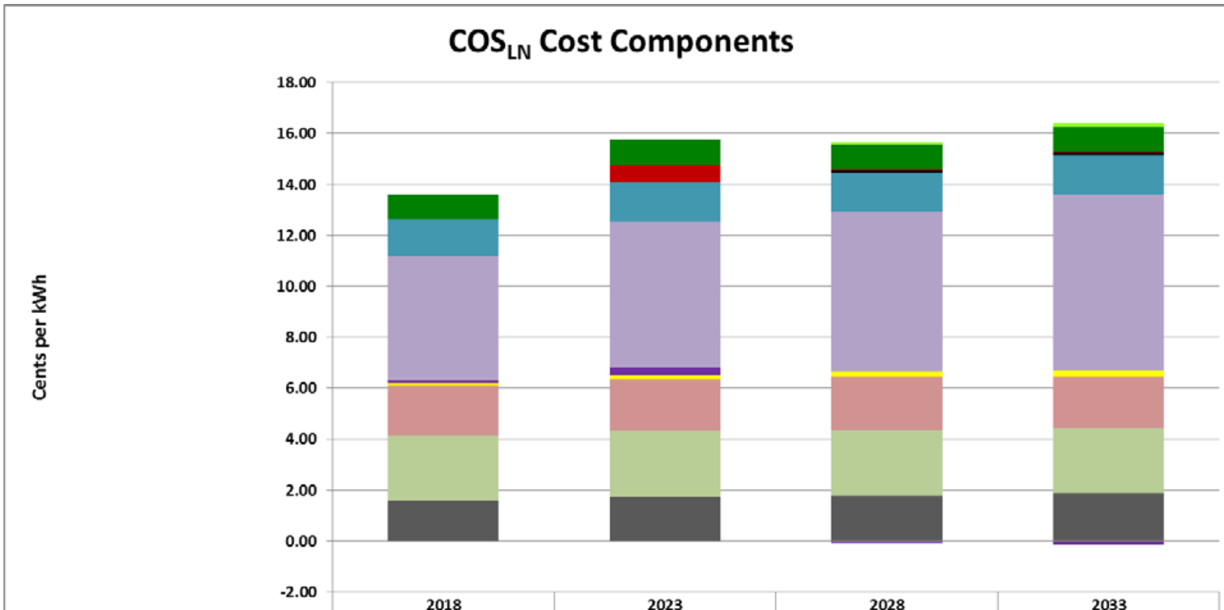
With respect to identifying a risk-integrated, least cost, optimal future resource portfolio, the three key, critical findings from the Chapter 10 through 12 studies were as follows:

1. Of all the different resource scenarios examined in Chapter 10, the forward market hedged scenarios clearly resulted in the least risk solutions. Note that the lowest COS_{LN} metrics were associated with the strong load growth, 33% RPS, 2025 IPP end-date scenario, but also that the minimal increased cost of moving to a 40% RPS (~0.14 ₵/kWh in 2033) was partially offset by the reduced risk estimate (~0.10 ₵/kWh).
2. After examining five alternative generation scenarios in Chapter 11 that could serve as realistic IPP replacement options, we were unable to identify any alternative that produced a lower, risk-integrated COS_{LN} metric than the forward market hedging option (initially examined in Chapter 10).
3. Upon reexamining our 33%, 40% and 50% RPS scenarios under two long-term pricing schemes, we concluded that the primary factor influencing the COS_{LN} metric was the renewable energy contract price, as opposed to the RPS level. Furthermore, reaching and maintaining a 40% RPS should be easily achieved in a cost-effective manner, provided renewable energy prices remain competitive.

Given these results, it is reasonable to propose that the <u>strong load growth</u>, <u>40% RPS</u>, <u>2025 IPP end-date</u>, <u>forward hedged market power</u> replacement scenario represents RPU’s optimal future portfolio configuration with respect to simultaneously minimizing both our load serving costs and risks.

Although the 33% RPS scenario does exhibit a slightly lower COS_{LN} metric, the 40% RPS by 2030 scenario can be argued to be more plausible (i.e., realistic) and exhibits almost the same "risk-integrated" cost forecast (i.e., cost + 2 standard deviations). This conclusion is conditional on the assumption that future renewable energy costs will remain near their current levels and that RPU executes future renewable energy purchases in a strategically optimal manner.

Under such an assumption, Figure 14.2.1 shows a breakdown of the forecasted COS_{LN} cost components for this future portfolio configuration for the forecast years 2018, 2023, 2028 and 2033. As shown in this figure, future wholesale load purchases represent our largest cost component, followed by "all other" utility costs (primarily personnel and infrastructure), bond debt payments (for current and future capital improvements), and general fund transfer payments. Our CAISO costs (TAC and Uplift charges) and 33% RPS cost components are also forecasted to be non-negligible, as are our expected post-2020 carbon costs (at least until our IPP contract ends).



	2018	2023	2028	2033
Incremental Renewable Cost 40% RPS	0.00	0.00	0.08	0.15
Renewable Cost 33% RPS	0.99	1.03	0.99	0.98
Carbon Cost	0.00	0.69	0.04	0.05
Market Hedge Cost (IPP Replacement)	0.00	0.00	0.11	0.10
CAISO Costs (TAC & Other Uplift)	1.43	1.51	1.51	1.53
Portfolio Costs (Load)	4.88	5.72	6.30	6.93
Portfolio Costs (Thermal Gen & Misc)	0.12	0.30	-0.10	-0.15
RA Cost	0.09	0.17	0.20	0.24
Bond Debt (Capital Improvements)	1.96	2.03	2.09	2.02
Personnel & All Other Utility Costs	2.58	2.58	2.57	2.56
GFT	1.57	1.73	1.79	1.87

Figure 14.2.1. Forecasted COS_{LN} cost components for RPU's optimal future portfolio configuration.

14.3 Additional Recommendations

A significant number of diverse resource planning issues have been discussed and analyzed in this 2014 Integrated Resource Plan. Although no IRP process can ever be expected to definitively answer all of the planning related questions that a utility might face, this same planning process can ideally provide objective evaluations of the most critical issues and questions. Additionally, this process can also help frame some high-level recommendations for these same issues and questions. In this spirit, we propose that the following five high-level recommendations should be given serious consideration.

Recommendation 1: Maintain Participation Flexibility in the CAISO Markets

As discussed throughout this IRP and specifically in Chapter 5, there are numerous regulatory mandates and CAISO initiatives that have the potential to significantly alter RPU's Power Resources costs. The details of many of these initiatives and mandates remain to be determined, but it is clear that significant implementation risks exist. More specifically, the combined impacts of these various initiatives and mandates may force RPU to consider alternative CAISO participation strategies in the near future. For example, RPU may need to adopt a real-time load following paradigm in order to circumvent potentially egregious future FRAC/MOO and Joint Reliability RA costs. Likewise, changes to the state-wide RPS and/or ES goals may force RPU to make additional renewable resource or energy storage purchases that we do not currently anticipate.

Thus, given the highly uncertain nature of the current regulatory paradigm, it is critical that RPU implement future procurement resource strategies that maintain the maximum possible flexibility. Additionally, RPU should position itself to quickly and cost-effectively shift its CAISO participation strategy, should such a need arise. It is clearly apparent that the CAISO is now and will continue to be struggling with numerous RPS/ES/DG integration issues, and that these issues will result in multiple millions of dollars of costs to CAISO members. RPU should therefore seek to minimize its exposure to these integration costs, using whatever means that are reasonably feasible.

Recommendation 2: Search for ES/DSM Synergies

With respect to the current ES mandates, we additionally recommend that RPU reexamine its current offering of DSM programs in an effort to identify and find possible synergies between specific demand side management and energy storage technologies. For example, thermal load shifting technologies for large commercial applications has long been recognized as a potentially cost effective DSM program. However, this technology is also be recognized as a valid ES option, and as such could be used to help partially meet/achieve future ES mandates.

The analyses presented in Chapters 6 and 12 of this IRP suggest that the implementation of additional thermal energy storage technology within the RPU service territory might be cost effective under certain situations. This idea should be carefully examined and analyzed when RPU performs its next set of comprehensive ES analyses. At the very least, this technology may prove to be the least cost prohibitive, should RPU be forced to meet an arbitrary, state-imposed ES mandate in the near future.

Recommendation 3: Continue to work towards a 40% by 2020 RPS Goal

RPU has positioned itself to significantly exceed the current state imposed RPS mandates under SB2. While the state mandate calls for each LSE to reach a 33% RPS by 2020, Riverside expects to reach a 37% RPS by 2019, before receiving any credit for our Historic Carry-over filings.

It is certainly possible that considerable cost pressures may arise in the next few years which might be partially offset by liquidating some of Riverside's long renewable energy positions. However, we advise that RPU proceed cautiously here, and avoid reducing our current "soft" 40% by 2020 RPS strategy simply for the sake of short-term cost savings. Legislative proposals have already been proposed that would increase the state imposed RPS mandate to a much higher level (such as 40% or even 50% by 2030). Given this, it would be advisable to allow for more time to elapse before modifying or changing our current procurement strategy. RPU is currently well positioned to meet these potentially higher levels with very minimal additional expenditures; we should not sacrifice this strategic position lightly.

Recommendation 4: Continue to Examine Viable IPP Alternatives

In Chapters 10 and 11 we performed a comprehensive analysis of seventeen different future portfolio scenarios based on two potential future load growth patterns, RPS mandates, and IPP contract termination dates, along with six different IPP replacement options. Each of these scenarios was examined in detail under simulation, specifically with respect to minimizing our expected cost of service over the next twenty year time horizon. In the Chapter 10 studies, replacing IPP with forward market hedged energy under either the 33% or 40% RPS mandates clearly produce the lowest composite cost of service estimates, and thus would be preferred under a "least cost, best fit" paradigm.

In Chapter 11 we examined five additional generation scenarios that could represent reasonable IPP replacement options, and compared these new scenarios to the forward market hedged energy scenario examined in Chapter 10. The five alternative replacement options examined in Chapter 11 consisted of (a) two types of new internal generation, (b) a decision to participate in the IPP Repower Project, (c) a decision to replace at least half of the IPP coal energy with a new long term renewable contract, and (d) the near-term participation in a commercial tolling contract. As in Chapter 10, our budgetary assessment of these alternatives considered both the expected values and simulated standard deviations of our fully loaded, forecasted cost of service. These secondary analyses suggested that most of these additional IPP replacement options could be feasible, but none of these options result in COS_{LN} forecasts that are lower than those observed for the forward market hedged energy strategy.

Currently, we expect that our IPP contract will continue for at least another six years (i.e., through 2020), and could remain in effect through the end of 2025. Thus, from a planning perspective, we are still at the very early stages of identifying an IPP replacement option, and there is ample time to identify and pursue one or more cost-effective alternatives. Therefore, it is advisable to continue examining and analyzing a full range of alternative replacement options, and avoid committing to any specific replacement option at this time. Further analyses can and should be performed on the options considered in this IRP (and perhaps other options not considered in this IRP), before any formal replacement decision(s) are made.

Recommendation 5: Continue to Monitor our Customer Solar DG Penetration Levels

Unlike the planning paradigm for replacing IPP, RPU is facing other resource allocation issues that are of a much more immediate concern. The potential for stranded fixed costs due to increasing levels of customer installed solar PV systems represents one of these more immediate issues that RPU should begin addressing now. More specifically, RPU might wish to seriously consider developing a community solar PV offering for our customer base, in order to offer our customers an attractive alternative to self-installed systems. Or alternatively, RPU may need to consider adopting an unbundled rate structure in the near future, in order to mitigate our revenue losses if our customer solar DG penetration levels continue to increase.

The utility industry is currently undergoing a significant "paradigm shift" in the United States. We are moving away from the concept of using large, centralized generation assets to supply our customers with power on a 24x7 basis and towards a more inter-dependent grid where both customer and smaller utility-scale distributed generation will play an increasingly important power serving role. RPU should begin shifting its business operational model accordingly to account for these paradigm shifts, preferably sooner rather than later.

14.4 Final Thoughts

In conclusion, the 21st Century is proving to be both a challenging and exciting time for the utility industry. While numerous risks currently exist in the ISO related markets (and the CAISO in particular), there are also unprecedented opportunities for public utilities to embrace and deploy new technologies and improve their business models to better serve their local customer base. While RPU has always had the discipline to maintain a healthy financial balance sheet and employ conservative risk control measures, our utility has also had the foresight to adopt progressive strategies and new technologies that provide financial and social advantages to our local community. Our mission continues to be to provide the highest quality water and electric services at the lowest possible rates to benefit the Riverside community. It is our sincere hope that the analyses, findings and recommendations presented in this 2014 Integrated Resource Plan assist Riverside Public Utilities to continue to achieve this goal in a proactive, intelligent, and optimal manner.

List of Acronyms

Acronym	Definition
AB	Assembly Bill
AC	Alternating Current/Air Conditioner
ADT	Average Daily Temperature
AEO	Annual Energy Outlook
AGR	Annual Growth Rate
AMI	Advanced Metering Infrastructure
AQMD	Air Quality Management District
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CAR	Cost At Risk
CARB	California Air Resources Board
CC	Combined Cycle
CCNG	Combined Cycle Natural Gas
CD	Cooling Degrees
C_E	Energy Cost
CEC	California Energy Commission
CF	Capacity Factor
CFL	Compact Fluorescent Lamp
CFO	Clean Fuels Outlet
CIMIS	California Irrigation Management Information System
CMUA	California Municipal Utilities Association
COS	Cost of Service
COS_{LN}	Load Normalized Cost of Service
CPI	Consumer Price Index
CPR	Coincident Peak Reduction
CPUC	California Public Utilities Commission
CRR	Congestion Revenue Right
CY	Calendar Year
DC	Direct Current
DF	Degree of Freedom
DG	Distributed Generation
DR	Demand Response

Acronym	Definition
DSM	Demand Side Management
E3	Energy and Environmental Economics, Inc.
EDC	Engineer, design, and construction
EE	Energy Efficiency
EEA	Energy Exchange Agreement
EERAM	Energy Efficiency Resource Assessment Model
EFW	Energy from Waste
EIA	Energy Information Administration
EIM	Energy Imbalance Market
EMP	Monthly Non-farm Employment
EPA	Environmental Protection Agency
ES	Energy Storage
F_{AS}	Ancillary Services Factor
FERC	Federal Energy Regulatory Commission
FRAC	Flexible Resource Adequacy Criteria
FYE	Fiscal Year Ending
GCOS	Gross Cost of Service
GE	General Electric
GFT	General Fund Transfer
GHG	Green House Gas
GR	Growth Rate
GWh	Gigawatts Hour
HL	Heavy Load
HP(MtM)	Hedging Payoff (mark-to-market)
HR	Heat Rate
HUEC	Hourly Unhedged Energy Cost
ICE	Intercontinental Exchange
IEPR	Integrated Energy Policy Report
IPA	Intermountain Power Agency
IPP	Intermountain Power Project
IRP	Integrated Resource Plan
ISO	Independent System Operator
kV	Kilovolt
LADWP	Los Angeles Department of Water and Power

Acronym	Definition
LED	Light Emitting Diode
LG	Load Growth
LL	Light Load
LSE	Load Serving Entity
Mid-C	Mid - Columbia
MMBtu	Million British Thermal Unit
MMT	Million Metric Tons
MOO	Must Offer Obligation
MOU	Memorandum of Understanding
MPSP	Maximum plausible savings potential
MRR	Mandatory Reporting Regulations
MRTU	Market Redesign and Technology Upgrade
MSE	Mean Squared Error
MSS	Metered Substation
MVA	Megavolt Ampere
MW	Megawatts
MWh	Megawatts Hour
NCOS	Net Cost of Service
NCPA	Northern California Power Agency
NEM	Net Energy Metering
NEP	Net Energy Position
NOB	Nevada Oregon Border
NPV	Net Present Value
OEM	Original Equipment Manufacturer
OEP	Open Energy Position
Open ADR	Open Automated Demand Response
OSI	Open Systems International, Inc.
OTC	Once Through Cooling
PBC	Public Benefit funds
PC	Personal Computer
PCC	Portfolio Content Category
PCM	Pulse Code Modulation
PCPI	Per Capita Personal Income
PG&E	Pacific Gas and Electric Co.

Acronym	Definition
PIRP	Participant Intermittent Resource Program
PO	Partial Ownership
POU	Public Owned Utilities
PPA	Power Purchase Agreement
PSC	Power Sales Contract
PTO	Participating Transmission Owner
PV	Photovoltaic/Palo Verde
PVNGS	Palo Verde Nuclear Generating Station
QF	Qualifying Facilities
RA	Resource Adequacy
R_E	Energy Revenue
RERC	Riverside Energy Resource Center
RMC	Risk Management Committee
RPM	Revolutions Per Minute
RPS	Renewable Portfolio Standard
RPU	Riverside Public Utilities
RTRP	Riverside Transmission Reliability Project
SB	Senate Bill
SCADA	Supervisory Control And Data Acquisition
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison Co.
SCGT	Simple Cycle Gas Turbine
SCPPA	Southern California Public Power Authority
SDG&E	San Diego Gas and Electric Co.
SEER	Seasonal Energy Efficiency Ratio
SEL	Schweitzer Engineering Laboratories, Inc.
SL	System Load
SONGS	San Onofre Nuclear Generation Station
SP	System Peak
STD	Standard Deviation
STS	Southern Transmission System
TAC	Transmission Access Charge
TES	Thermal Energy Storage
TGC	Total Generation Cost

Acronym	Definition
TGR	Total Gross Revenue
TLC	Total Load Cost
TNPC	Total Net Portfolio Costs
TOU	Time of Use
TREC	Trackable Renewable Energy Credits
TRR	Transmission Revenue Requirement
UEC	Unhedged Energy Cost
UFOC	Uplift Fees and Other Costs
WECC	Western Electricity Coordinating Council
WKN	WKN(Wind Kraft Nord) Wagner
WLG	Weather, Load and Generation
WSPP	Western Systems Power Pool
XHD	Extended Heating Degrees
ZEV	Zero Emission Vehicle

APPENDIX A

A.1 Ascend PowerSimm Simulation Framework

The Ascend solution values portfolios consisting of structured transactions, generation assets, load obligations, and hedges plus operating components of transmission, ancillary services, and conservation programs. The hierarchical portfolio structure of PowerSimm enables portfolio components to be valued individually or jointly as an element of the parent portfolio. The valuation of a utility portfolio or structured transaction follows from the application of analytic algorithms that optimize asset values and calculate hedge, load, and structured transaction values relative to underlying Monte Carlo simulations. Recognizing the importance of meaningful Monte Carlo simulations to valuations of portfolios and structured transactions, we present an overview of Ascend's simulation methodology below.

The simulation framework of PowerSimm addresses uncertainty as viewed through today's market expectations (forward prices) and the future realized delivery conditions for load, spot prices, and generation. PowerSimm supports the ability to modify inputs, model impacts, and evaluate key sources of uncertainty. The framework to simulate physical and financial uncertainty follows the process flow of Figure A.1.1. The simulation of volumetric and market prices further extends the correlated simulation of forward prices to model structural relationships during delivery. Examples of such relationships include weather on load, load on market prices, and gas and load on electric prices. Additionally, relationships with very limited historical information can be modeled by specifying statistical distributions on values such as CO_2 or REC prices. PowerSimm also performs fundamental modeling of demand and supply conditions to forecast market prices beyond the liquid portion of the forward curve.

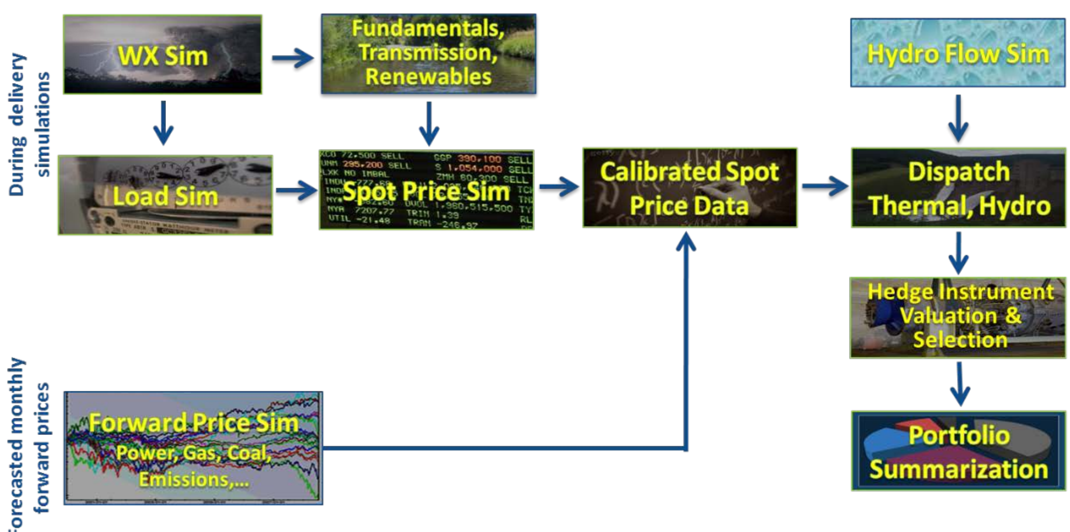


Figure A.1.1. PowerSimm simulation framework.

Simulation of electric system and customer loads follow from a common analytical structure that seeks to preserve the fundamental relationship between demand and price. The simulation process is divided into two separate components: 1) prior to delivery and 2) during delivery. The prior-to-delivery simulation of forward prices evolves current expectations through time from the start date to the end of the simulation horizon. The simulations during delivery capture the relationship of physical system conditions (i.e., weather, load, wind, run-of-river hydro, unit outages, and transmission) on market prices. The inter-relationship between 'prior-to-delivery' and 'during-delivery' simulations is central to linking expectations to realized observations that are either simulated or actual. Figure A.1.2 presents a graphical representation of this process.

For forward contracts representing prior-to-delivery simulations, monthly prices are evolved into the future from the current market prices to expiration for each contract. This process of evolving forward contracts into the future utilizes the current forward strip (market expectations of future prices) and the observed behavior of forward contract uncertainty and covariate relationships to create future price projections. For each simulation, the final evolved forward price becomes equal to market expectations. The average of the forward price simulations for each monthly contract will equal the final evolved spot price. During the prior-to-delivery simulations, monthly forward contracts are correlated with each other and across commodities. Seasonal hydro conditions are also correlated with the simulated forward prices.

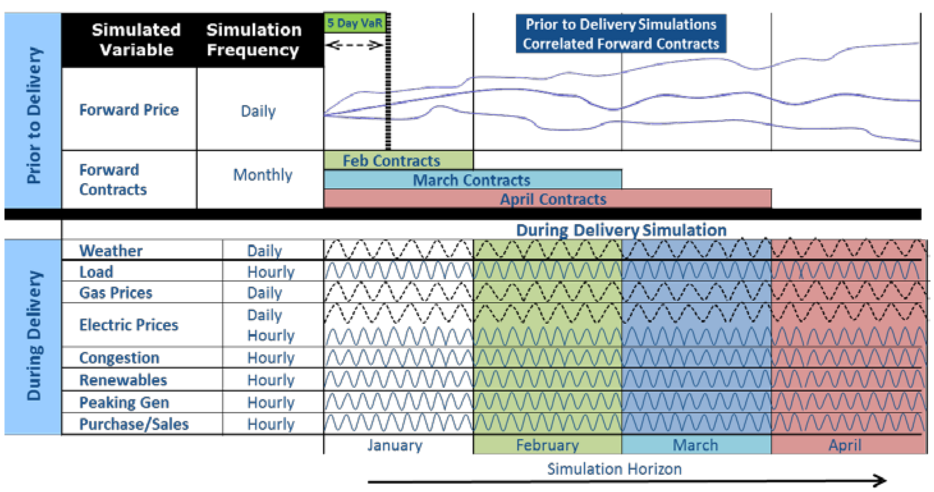


Figure A.1.2. Simulation framework of forward and spot prices.

The during-delivery simulation process begins with simulation of weather. PowerSimm simulates up to approximately 30 different weather variables (e.g., daily min/max temperatures) for user-specified weather stations using a cascading Vector Auto-Regression (VAR) approach. This approach maintains both the temporal and spatial correlations of weather patterns for the region with a 3-step process. Ascend applies a cascading VAR approach to maintain inter-month temperature correlations consistent with the historical data. For example, if a hot July is likely to be followed by a hot August, the cascading VAR does a superior job of capturing this effect. The application of weather simulations supports the analysis of uncertainty through hundreds of weather scenarios without the limitation of the pure historical record where extreme weather events beyond observed conditions may occur (but obviously with a low probability). The second step of the process combines these weather simulations for input into the load simulation process. PowerSimm offers the capability to weight weather stations together. Typically this is done via energy or population weighting.

PowerSimm incorporates external demand factors, scaling and shaping the simulated loads to match forecasted monthly demand and peak demand values. The simulations of electric load use a state-space modeling framework to estimate seasonal patterns, daily and hourly time series patterns, and the impact of weather. The state-space framework of PowerSimm produces unparalleled benchmark results that reflect the explained effects of weather and time-series patterns and the unexplained components of uncertainty. State-space modeling uses the regression equations to explain the variability in price as it relates to demand.

The during-delivery simulation of prices addresses the more intuitive simulations of system conditions and spot prices. System conditions of unit outages, supply stack composition, system imports and exports, and transmission outages are modeled and simulated independently of weather, but also serve as determinants to the spot price of electricity.

PowerSimm dispatch models forced outages (off-line and derates). The stochastic component of forced outage modeling captures the uncertainty in outage duration. Users can specify the maintenance schedule or elect to have PowerSimm optimize the maintenance schedule with reserve requirements observed.

Finally, PowerSimm enables users to readily perform sensitivity runs by supplying percent scaling factors to the “base” level key components of uncertainty. These sensitivity runs can be input and run in batch mode.

A.2 Simulation Engine: Overview

The analytic processes to PowerSimm reside in the SimEngine. The heart of the Simulation Engine is a Monte Carlo simulation of physical elements and market prices. The SimEngine produces Monte Carlo simulations of weather, load, market prices, and wind and solar generation. This section discusses the analytic methodology of the SimEngine and the specific model structure to simulate the following elements:

1. Weather
2. Load
3. Forward Market Prices
4. Spot Electric Prices

5. Spot Gas Prices
6. Wind and Solar Generation

A.2.1 State Space Modeling

State-space modeling in its simplest form is regression analysis with uncertainty. The uncertainty associated with regression analysis can be used to explain how weather relates to load or how yesterday's forward price relates to today's forward price. Simple regression analysis seeks to maximize the predictive capabilities of the explanatory variables on the dependent variable. An example of a simple linear regression equation is shown below and in Figure A.2.1.

$$Y = intercept + \beta X + \varepsilon$$

The regression line provides the best fit between the individual x values and maximizes the predictive value of each x observation and the dependent y variable. There exists several components of uncertainty in this equation including: i) uncertainty in the coefficient estimate β, ii) uncertainty in the residual error term ε, and iii) the covariate relationship between the uncertainty in β and the residual error. State-space modeling captures these elements of uncertainty.

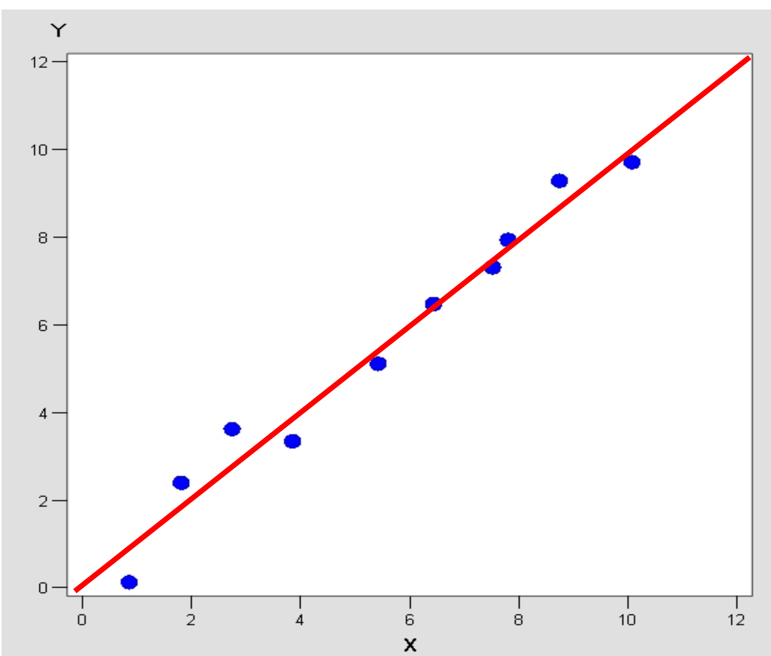


Figure A.2.1. Example of a traditional regression analysis.

For example, ten Monte Carlo simulations are shown in Figure A.2.2. The regression line is no longer completely straight because the state-space Monte Carlo simulations capture the uncertainty in the slope and add an element of random noise (i.e., residual error). The simulations also capture the covariate relationship between the uncertainty in the coefficient estimates and the residual error. By preserving the covariate relationships between the coefficients and the residual error we are able to maintain the relationship of the original data structure as we propagate results through time.

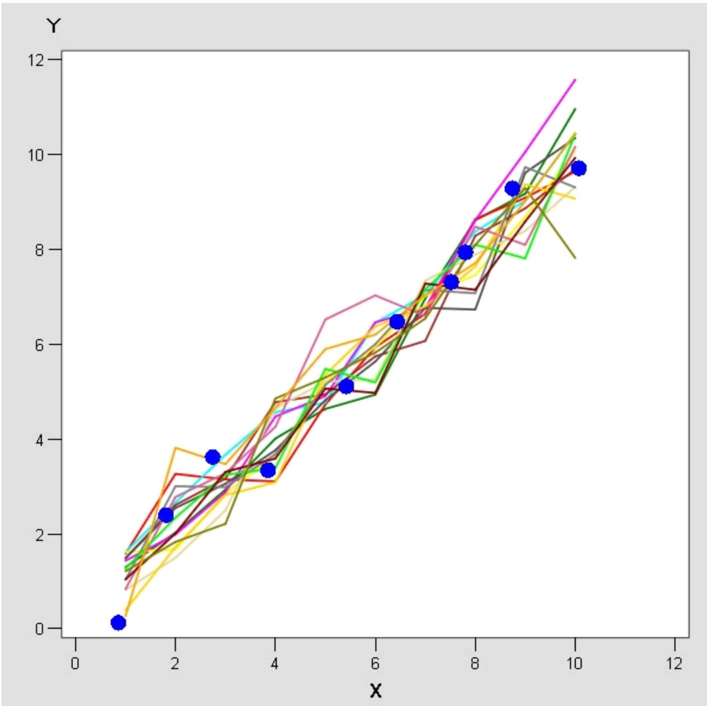


Figure A.2.2. Monte Carlo simulations.

The simulation results shown above are for a single equation, which could correspond to a utility load or a nodal price. The simulation estimates capture the effect of uncertainty in the individual parameter estimates, as well as the residual error and the covariate relationship between the uncertainty distribution in the coefficient estimates and residual error. For a system of equations, correlation effects between equations are captured through the residual error term.

In this report, state-space modeling serves as the cornerstone of uncertainty analysis. The logic of the linked physical and market relationships needs to be supported with solid benchmark results, which demonstrate the statistical match of the input values to the simulated data.

Parameter Estimation

The complexities of time series data can best be captured through the estimation of the state-space coefficients and conditional uncertainty estimates with full information maximum likelihood estimation (FIMLE). The FIMLE procedure allows for both the model estimation and the simulation of load based on perturbations of the parameter estimates that account for uncertainty of coefficient estimates and equation errors. FIMLE also accounts for the effects caused by temporal autocorrelation. For example, to accurately reproduce the distribution of load, we need to have more than weather as a stochastic variable. By introducing additional variance through the coefficients and residuals of the regression, we can more effectively simulate the realized outcome and pattern of electricity demand.

The first step is to combine the historical parameters needed for the model estimation, which include all of the variables needed for the parameters described above. Then, based on the input data, the model equation is then constructed and fit in with the parameter estimates and equation errors being stored. These estimates are then fed into a series of statements that simulate load for the next two years based on both weather simulations that are previously generated, perturbations of the parameter estimations, and equation errors. Normally, this is done in a symmetric manner where *i* load simulations are run on *i* weather simulations for a total of 2*i* simulations.

Weighting of Data

PowerSimm applies a weighting system to the input data that enables end users to adjust the emphasis of different historic events or time periods in the parameter estimation process. Each simulation module comes with a default weighting system. The default weighting system can be replaced by user-defined weights enabled through the PowerSimm user interface.

A.2.2 Weather Simulation

Understanding variability in climate data is important for accurate characterization of electricity load and price volatility. Climate dynamics are too chaotic for individual daily events to be accurately forecast. Therefore, it is often best to quantify a climate data variable on a monthly time step. Since the specific daily weather events of the upcoming months cannot be accurately anticipated, they are relegated to random phenomena within monthly probability distributions based on historical and forecasted climate data.

Though regarded as ‘random’ phenomena, daily weather events are correlated both in time and space. In other words, weather events observed today can influence weather events tomorrow and weather events observed in one location can be correlated with weather events in other locations. A straightforward way to represent the statistics of daily weather variations is the class of spatial-temporal models for surface weather data known as weather generators.

The purpose of a weather simulation is to provide a set of outcomes for simulated daily and hourly weather variables (e.g., daily min and max dry bulb temp) across 20 or more weather stations in the target region (e.g., Southern California). The simulation would maintain the appropriate correlation of observations among the weather stations.

In the modeling framework, weather forecasts are used as inputs to the short-term weather simulation model, but they can also be used as inputs to the long-term weather simulation model. Seasonal weather forecasts adjust the simulated mean and variance from long-run expectations to coincide with the forecast expectations. The long-run expectations are developed from historic values realized over the last 20 years. These forecasts provide a consistent set of weather realizations through Monte Carlo simulations, and are then fed into the overall simulation engine.

Analytical Scope

Weather simulation focuses on providing all weather explanatory variables used in the simulation of load. The model automatically works with the historic time series data specific to each weather station and determines the relationship between neighboring weather stations. This allows for consistent simulation of weather.

Analytical Applicability

Both Customer and System load are driven from simulated weather. Therefore, the use of weather simulation as a primary driving factor would enable a PowerSimm routine to preserve the appropriate relationship between customer load and spot prices. PowerSimm utilizes a Monte Carlo simulation whereby a specified number of equally likely events (realizations) influence a set of outcomes. These outcomes are comprised of realized weather values to capture weather for each station and the relationship to other stations in California (or the Western US).

Input Data

The core of a weather simulation engine runs on a dataset containing the requested covariates to be simulated. The data is presented in columns and sorted by date on a daily time step. This allows the engine to estimate the simultaneous and lagged correlations between all of the covariates.

Historic weather data is input into WeatherSimm through the Oracle database. (National Climate Data Center (NCDC) has been Ascend's preferred data source for historic data) Uploaded historic weather data should be consistent with the frequency of population of load data.

For long term (2+ years) simulations, trends in the historical data can be determined along with long-term weather forecast predictions made by groups such as the Climate Prediction Center (CPC) of the U.S. National Centers for Environmental Prediction, (NCEP) and the International Research Institute (IRI) for Climate Prediction.

Output Data

As described above, the core engine runs on a dataset where the covariates are represented by columns in a single dataset. The core engine generates an identical simulation output dataset with an additional variable that identifies the simulation number. This dataset can be restructured into any format required.

A.2.3 Load Simulation

Developing accurate electricity load simulations is critical for determining the cost of service, risks, and hedging strategies. In addition, load simulation has significant bearing on electricity prices because of the strong non-linear relationship between electricity load and prices. Traditional mathematical statistics may not be able to represent full distributions of load. A simulation approach is advantageous where a specified number of likely events (realizations) can be used in conjunction with simulated weather parameters. The combination of weather and load simulations provides a unified simulation process that can be used to estimate the potential long-term load.

Input Data

All load simulations are based on historical actual hourly load values. Projected economic/load growth input variables can also be applied, when available. For utility or large customer load, a minimum of one year of historic data is required. External load forecasts can be applied to create the expected value of load forecasts. External forecasts can be in the form of either monthly demand or a specified 8760 load stream. These forecasted values become the expected value of the simulated load.

Output Data

The output data is identical to the hourly historic input load dataset except that it includes the requested number of load simulations for the requested simulation length. This dataset also includes the simulation date and time update along with a link table to describe the parameters used to run the simulation.

Model Specification

The simulation of electric load captures the uncertainty in electricity demand through the PowerSimm module LoadSimm. Variation in electricity load can be broken down into three structural components:

- Calendar aspects of 'load shapes' both on an hourly and daily basis,
- Weather parameters that influence load,
- Temporal autocorrelation within load.

The structural components of load include hour of day (HOD) and day of week (DOW) load shapes, and interaction between HOD and DOW. Holidays, seasonal trends, and long-term growth predictions are also important components, but the main explanatory factor for load is weather. An example of this simulated relationship is shown in Figure A.2.3. The current model structure simulates system and utility load.

Temporal autocorrelation within load allows for temporally correlated errors to be modeled with more detail. This takes into account the temporal correlation in the model estimation.

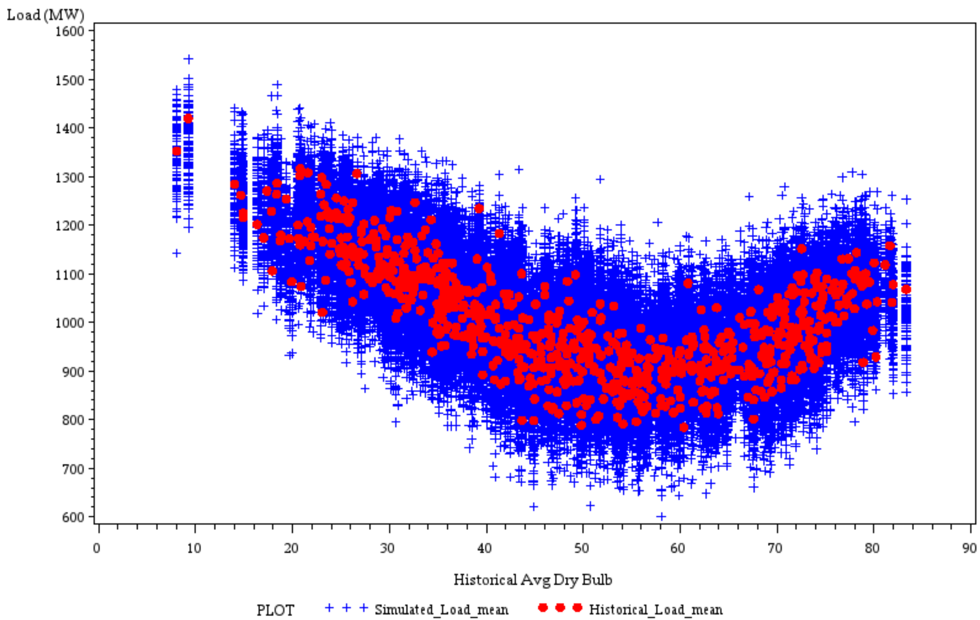


Figure A.2.3. Simulated and historical load and weather data.

A.2.4 Forward Prices

PowerSimm simultaneously simulates multiple strips of forward curves into the future where parameters for the stochastic processes and the covariate factors are estimated from historic data. PowerSimm builds a system of simultaneous equations that captures the stochastic component of each individual forward contract and the covariate relationship between neighboring contract months, other commodities, and other factors (such as interest rates and exchange rates). The state-space modeling framework satisfies the criteria for developing a "Cash Flow at Risk" solution by producing simulations of prices that are realistic, benchmark well to historic data, and produce a payoff of cash flows consistent with market option quotes at multiple strike prices. The consistency of simulated prices with market expectations remains the principal benchmark criteria for forward market simulations.

Input Data

PowerSimm requires a history of forward price quotes for each delivery month to simulate market prices into the future.

Output Data

PowerSimm outputs simulations of forward quotes to expiration for each contract. The simulations can be run on either a daily time step or a single time step until expiration. The simulation of forward prices produces a large number of simulated values. The reporting of these values is presented in terms of summary statistics that can be viewed in the standard output reports, which focus on the mean, 5^{th}, and 95^{th} percentile of simulation results.

Model Specification

The simulation of forward prices follows a state-space modeling framework. The correlation structure between each contract is preserved through a covariance matrix that maintains the covariate movements in uncertainty for different contracts and between different commodities. As a base simulation assumption, PowerSimm creates convergence between the initial forward price and the final forward price. PowerSimm also has the ability to weight the historic data used in the parameter estimation process to give more weight to more recent events and to reduce the leverage factor associated with outlier events.

A.2.5 Spot Electric Prices

Relationships between fundamental variables and electricity prices are measured from historic data. The simulated variables of load, hydro generation, imports/exports, reserve margins, supply stack, and gas prices are then used as explanatory variables for electricity prices through a structural state space model.

Within SimEngine, the process culminates in the simulation of spot electricity prices. Spot electricity prices preserve the weather, load, and price relationships that govern electric market price formation. The simulation inputs consist of the following modules:

- WeatherSimm
- LoadSimm
- HydroSimm
- TransSimm/Imports/Exports
- Gas Price Simulation Engine

These modules produce explanatory variables for electric spot market prices. Each simulation trajectory for heavy load (HL) and light load (LL) spot electric prices for each month are scaled to the final evolved forward price for electricity. The simulated daily HL and LL values are then further decomposed into hourly values with a state-space time series model.

The hourly-simulated values of load, price, and congestion flows are then input into economic dispatch and hedge payoff processes. The final simulated values are then written to the Results Database.

Input Data

The input data consists of the following (with the optional explanatory variables notes in parentheses following the data element):

- Historic hourly load data
- Historic hourly or daily hydro generation
- Daily gas prices
- Transmission imports and exports (optional)
- Daily reserve margins (optional)
- Supply stack characteristics (optional)

Output Data

SimEngine produces simulation of daily HL and LL electric prices and hourly spot electric prices. Summary statistics can be viewed in the standard output reports, which focus on the mean, 5th, and 95th percentile simulation results.

Methodology and Model Specification

The application of the fundamental drivers of electricity has influence on the daily and hourly formation of prices over both the intermediate and long-term prices. Over the intermediate term, daily HL and LL electricity prices are simulated so that the mean distribution of daily prices converges with the final evolved forward price.

Regional electricity prices are primarily a function of daily gas prices and daily reserve margins. Each variable explains about 50% of the variability in prices and jointly they explain about 90% of the variability

The simulation of electricity prices follows the simulation of the exogenous variables that jointly explain electricity prices. These variables include gas prices and load and may also include unit outages, capacity, supply stack characteristics, hydro generation, imports, and exports. The variables load, unit outages, capacity, imports, and exports are factored directly into the calculation of daily reserve margins.

The simulated values for price are conditional upon the path-dependent weather and load simulations. The mean or median of the realized daily HL and LL spot prices are bucketed into monthly time steps and scaled to be centered around the monthly forward price.

A.2.6 Spot Gas Prices

Developing accurate spot gas price simulations is critical for determining the cost of service, risks, and hedging strategies. A simulation approach is advantageous where a specified number of likely events (realizations) can be used in conjunction with exogenous system shocks such as extreme weather events. The combination of market electric prices and spot gas prices is critical to accurately capturing the cost of generation and driving dispatch of generation assets.

Input Data

Estimation of the parameters to simulated spot gas prices utilizes input of historical gas spot prices, weather, and daily HL and LL electric prices. The simulated weather is input into the model on a simulation basis.

Output Data

The output data is identical to the daily historic input dataset except that it includes the requested number of spot price simulations for the requested simulation length. This dataset also includes the simulation date and time update along with a link table to describe the parameters used to run the simulation.

SimEngine produces daily spot gas price simulations over the forecast horizon. The summary statistics can be viewed in the standard output reports, which focus on the mean, 5^{th}, and 95^{th} percentile simulation results.

A.2.7 Wind and Solar Generation

Developing accurate wind and/or solar generation simulations is critical for determining cost of service, risks, hedging strategies, and for estimating the relationship between the explanatory variables and price. Traditional mathematical statistics may not be able to represent full distributions of such generation. A simulation approach is advantageous where a specified number of likely events (realizations) can be used in conjunction with simulated weather parameters. The combination of weather and wind/solar generation simulations provides a unified simulation process that can be used to estimate the relationship between wind/solar production, electricity demand, and market prices.

Input Data

WindSimm requires input of historical hourly wind or solar generation. For new assets, the estimated hourly data is used for input values.

Output Data

The output data is identical to the hourly historic input wind/solar generation dataset except that it includes the requested number of simulations for the requested simulation length. This dataset also includes the simulation date and time update along with a link table to describe the parameters used to run the simulation.

WindSimm produces simulations of hourly wind/solar generation over the forecast horizon. WindSimm summary statistics can be viewed in the standard output reports, which focus on the mean, 5th, and 95th percentile simulation results.

Methodology and Model Specification

Variation in wind/solar generation can be broken down into three structural components:

- Calendar aspects of ‘generation shapes’ both on an hourly and daily basis
- Weather parameters that influence generation
- Temporal autocorrelation within the generation data

The structural components of wind/solar generation include hour of day (HOD) and seasonal trends. The relationship between generation and electric load is maintained by using temperature as an explanatory factor.

Integration of these components into a modeling framework requires that the significant interactions among the components be taken into account. Weather parameters impact hourly and daily generation profiles depending on the HOD. There are also differences in the temporal autocorrelation contingent on seasonality. The combination of these main effects and their significant interactions can be used to accurately simulate generation.

WindSimm has three main components that influence changes in wind/solar generation. The first is the structural components that develop the ‘production shapes’ both on hourly and daily basis marked with bold fonts. The second is the weather variables that influence generation. The third is the temporal autocorrelation observed in the generation data. Beyond these main effects, there are significant interactions between these components that are incorporated for model accuracy.

A.3 Generation Dispatch

In PowerSimm, units are dispatched against multiple simulation sets of price, load and emissions, allowing for a distribution of outcomes. The core dispatch routine is based on a deterministic dynamic program-type model with backward and forward passes.

The setup configuration for Dispatch can be modified to maximize granularity and realism of unit operation or to maximize processing speed. Dispatch can also run autonomously from PowerSimm for short-term and high-granularity dispatch simulations. Greater speed can be achieved through simplifying unit characteristics and/or increasing the size of the simulation time step (e.g., from hourly to 4-hourly time step size).

Generation units are economically dispatched by finding the sequence of states for the unit hour-by-hour that maximizes the Total Net Revenue (Total Gross Revenue – Total Production Costs). Even when a collection of units is being dispatched to serve native load, it is treated as being dispatched economically, subject to a constraint condition: the overall portfolio of units should minimize the cost of production while maximizing revenue (if any) and subject to the condition that native load is serviced.

In addition to serving native load, units may also be constrained by a maximum number of starts in a month or how much of a specific emission they can generate. To enforce these constraints, penalties are added to the Net Revenue equation. These "economic" penalties and incentives do not show up in the final report on Costs and Net Revenue; they are simply used to satisfy the constraints. This modified Net Revenue equation represents the new objective function. The mathematical problem of dispatch is to maximize the cumulative total value expressed by this function.

Peak-period and seasonal unit characteristic changes are handled by identifying a unit. When unit characteristics change radically between seasons, the dispatch may be split into separate blocks; effectively modeling the different blocks as separate units and then splicing their results.

Planned outages are represented by assigning large negative objective function values to all "ON" states for the outage period. Partial Planned Outages act in the same manner, but are restricted to generation levels beyond the specified threshold. Unplanned or Forced outages are deemed to take the unit operator "by surprise". Unplanned outages are generated via random simulation.

Certain operational constraints (such as total generation limits, maximum starts, and emissions) involve iterative dispatch simulations using different adjustments to the objective function. The iterative dispatch loop seeks to obtain the minimum objective function adjustments that result in a dispatch result that obeys the conditions of the constraint. Startup/shutdown time, minimum run time, minimum down time and fuel switching constraints are all handled directly through the state-to-state mapping tables rather than through the objective function.

Finally, the PowerSimm dispatch engine can be configured to produce portfolio asset and dispatch simulations at the hourly granularity for one month to twenty-five (25) years into the future. The end-user can specify the number of simulations, the time step granularity, the generation asset portfolio, multiple portfolio constraints and stress test scenarios, and the degree of detail in the output data tables. All output data is delivered via the OLAP cube into Excel pivot-tables; these tables can then be further customized and modified by the end-user, to meet specific reporting and/or computational applications.

APPENDIX B

B.1 System Load Model: Statistical Details

The regression component of our monthly total system load forecasting model is a function of our two economic drivers (PCPI and EMP), two calendar effects that quantify the number of weekdays (SumMF) and weekend days (SumSS) in the month, two weather effects that quantify the total monthly cooling and extended heating degrees (SumCD and SumXHD), and four low order Fourier frequencies (Fs(1), Fc(1), Fs(2) and Fc(2)). Additionally, the heterogeneous residual variance (mean square prediction error) component is defined to be a function of two low order Fourier frequencies (Fs(1) and Fc(1)). Mathematically, the model is defined as

$$\begin{aligned} y_t &= \beta_0 + \beta_1[PCPI_t] + \beta_2[EMP_t] + \beta_3[SumMF_t] + \beta_4[SumSS_t] + \beta_5[SumCD_t] \\ &+ \beta_6[SumXHD_t] + \beta_7[Fs(1)_t] + \beta_8[Fc(1)_t] + \beta_9[Fs(2)_t] + \beta_{10}[Fc(2)_t] + h_t\sigma^2 \end{aligned} \qquad \text{Eq. B.1}$$

where

$$h_t = \exp\left\{\alpha_1[Fs(1)_t] + \alpha_2[Fc(1)_t]\right\}. \qquad \text{Eq. B.2}$$

In Eq. B.1, y_t represents the RPU monthly total system load (GWh) for the calendar ordered monthly observations and forecasts (t=1 → Jan 2003, t=384 → Dec 2033) and the seasonally heterogeneous residual errors are assumed to be Normally distributed and temporally uncorrelated. Eqs. B.1 and B.2 were simultaneously optimized using restricted maximum likelihood estimation (SAS AutoReg Procedure).

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 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

$$Var(\hat{y}_t) = \hat{h}_t\hat{\sigma}^2_{MSPE} + Var\left\{\hat{\beta}_5[SumCD_t] + \hat{\beta}_6[SumXHD_t]\right\} \qquad \text{Eq. B.3}$$

where $\hat{\sigma}^2_{MSPE}$ 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 simulation, once the parameters associated with the SumCD and SumXHD weather effects have been estimated.

B.2 System Peak Model: Statistical Details

The regression component of our monthly system peak forecasting model is a function of our two economic drivers (PCPI and EMP), three weather effects that quantify the total monthly cooling needs, maximum three-day cooling requirements (i.e., three-day heat waves) and the maximum single day heating requirement (SumCD, MaxCD3 and MaxHD, respectively), and six lower order Fourier frequencies (Fs(1), Fc(1), Fs(2), Fc(2), Fs(3) and Fc(3)). Once again, the heterogeneous residual variance (mean square prediction error) component is defined to be a function of low order Fourier frequencies (four frequencies in this model: Fs(1), Fs(2), Fc(1) and Fc(2)). Mathematically, the model is defined as

$$\begin{aligned} y_t = \beta_0 + \beta_1[PCPI_t] + \beta_2[EMP_t] + \beta_3[SumCD_t] + \beta_4[MaxCD3_t] + \beta_5[MaxHD_t] \\ + \beta_6[Fs(1)_t] + \beta_7[Fc(1)_t] + \beta_8[Fs(2)_t] + \beta_9[Fc(2)_t] + \beta_{10}[Fs(3)] + \beta_{11}[Fc(3)] + h_t\sigma^2 \end{aligned} \qquad \text{Eq. B.4}$$

where

$$h_t = \exp\left\{\alpha_1[Fs(1)_t] + \alpha_2[Fc(1)_t] + \alpha_3[Fs(2)] + \alpha_4[Fc(2)]\right\}. \qquad \text{Eq. B.5}$$

In Eq. B.4, y_t represents the RPU monthly system peaks (MW) for the calendar ordered monthly observations and forecasts (t=1 → Jan 2004, t=372 → Dec 2033) and the seasonally heterogeneous residual errors are assumed to be Normally distributed and temporally uncorrelated. Eqs. B.4 and B.5 were again simultaneously optimized using restricted maximum likelihood estimation (SAS AutoReg Procedure).

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

$$Var(\hat{y}_t) = \hat{h}_t\hat{\sigma}^2_{MSPE} + Var\left\{\hat{\beta}_3[SumCD_t] + \hat{\beta}_4[MaxCD3_t] + \hat{\beta}_5[MaxHD_t]\right\} \qquad \text{Eq. B.6}$$

where $\hat{\sigma}^2_{MSPE}$ 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 simulation after the parameters associated with the SumCD, MaxCD3 and MaxHD weather effects were estimated.

APPENDIX C

C.1 Derivation of the 1.9 multiplication Factor for the CAR Calculation

By definition, the Value-at-Risk (VAR) metric and/or Cost-at-Risk (CAR) metric for an observed or simulated distribution of data is defined to be the difference between the 95th percentile and the mean. Mathematically, this can be expressed as

$$VAR\ or\ CAR = P_{95} - Mean$$

This definition is very practical, in the sense that it makes no assumptions about the statistical properties of the underlying data distribution.

When one can make a reasonable assumption about the type of statistical distribution that the data arises from, it is also possible to express the VAR and CAR metrics as a simple function of the standard deviation. For example, if the data arises from a Normal distribution with a mean of μ and a standard deviation of σ, then it is simple to show that CAR = 1.65σ. Note that 1.65 represents the appropriate multiplication factor (*F*) that solves the constraint equation

$$\frac{E\{P_{95}\} - \mu}{\sigma} = F$$

where *E*{ } represents the expectation and $E\{P_{95}\} = \mu + 1.65\sigma$, etc.

The Normal distribution is not a particularly good approximation to most data distributions that are derived from observed or simulated market price data. However, the Lognormal distribution often is a good approximation (particularly for cost-based metrics), since most production cost modeling platforms simulate market price data using Lognormal distribution functions. (Note that the Ascend software follows this approach; i.e., the log of the mean-adjusted price data follows a Normal distribution, hence the mean-adjusted price data follows a Lognormal distribution.) Under the assumption that log(X) follows a Normal(μ, σ) distribution, where X represents the data being examined, the expected values of the mean, standard deviation, and 95th percentile of the back-transformed data are:

$$Mean(X) = \exp(\mu + 0.5\sigma^2) = \exp(\mu)\exp(0.5\sigma^2)$$

$$Standard.Deviation(X) = \exp(\mu)\sqrt{\exp(\sigma^2)\,[\exp(\sigma^2) - 1]}$$

$$P_{95}(X) = \exp(\mu + 1.65\sigma) = \exp(\mu)\exp(1.65\sigma)$$

Upon plugging these expectations into the constraint equation, we obtain the following formula for the multiplication factor:

$$F = \frac{\exp(1.65\sigma) - \exp(0.5\sigma^2)}{\sqrt{\exp(\sigma^2)[\exp(\sigma^2) - 1]}}$$

This formula does not yield a single solution, but instead represents a nonlinear function of the standard deviation. However, it can be readily verified that the maximum value that the factor can take is approximately 1.9 (see Figure C.1), and this value lies within the range of 1.7 to 1.9 for reasonable values of σ (e.g., $0.1 < \sigma < 1$). Thus, for Lognormally distributed data distributions, a VAR or CAR metric calculated as 1.9 times the observed standard deviation should yield a reasonable (abet possibly conservative) estimate, as compared to the traditional VAR or CAR calculation.

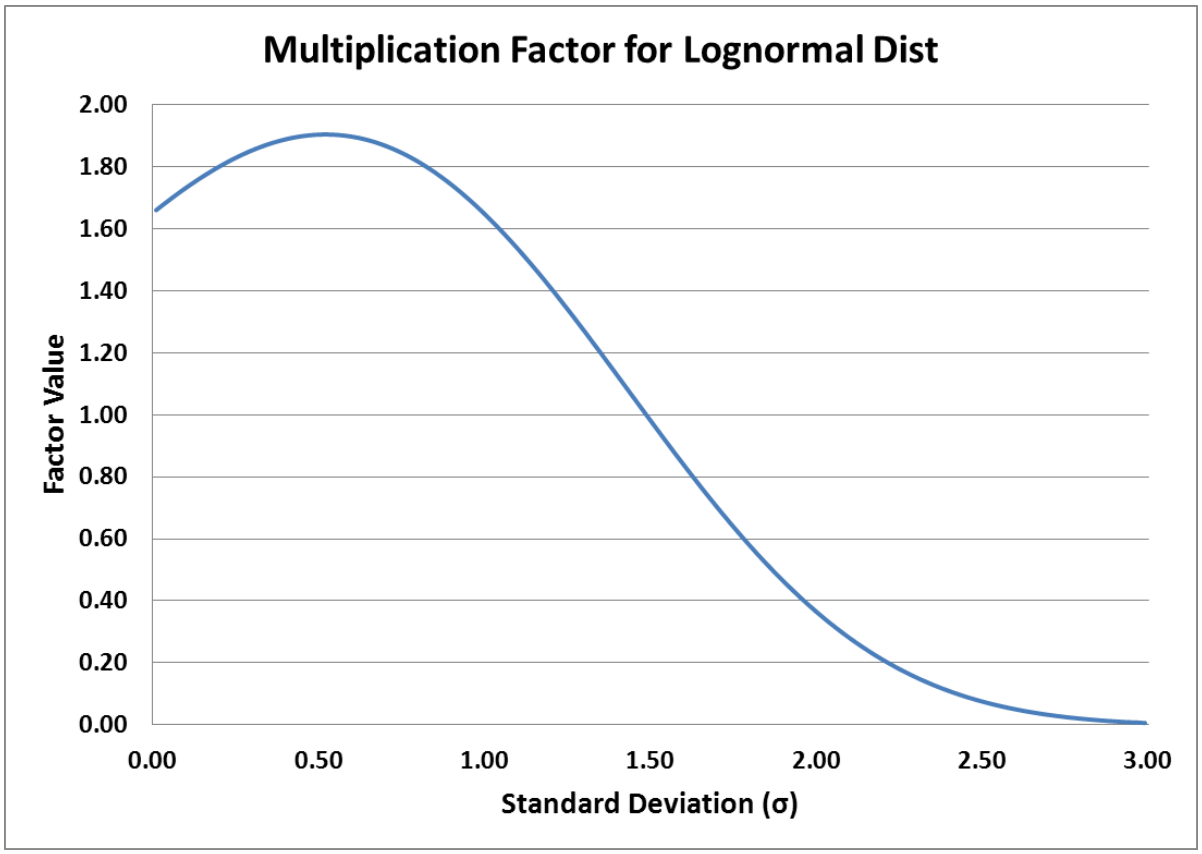


Figure C.1. A plot of the VAR and/or CAR multiplication factor for Lognormally distributed data, as a function of standard deviation (of the log-transformed data).

APPENDIX D

Power Resource Budget Projections: Primary Metrics
10 Yr Budget Report:2014-12-26 BatchId 901 - RPU Master Long Term
*****All Costs/Revenues in ($1000)*****

Line		FY 2014/2015	FY 2015/2016	FY 2016/2017	FY 2017/2018	FY 2018/2019	FY 2019/2020
1							
2	**Capacity Cost**						
3	Hoover	$ 815	$ 824	$ 828	$ 805	$ 809	$ 809
4	IPP Detail - Emissions	$ 36,100	$ 28,821	$ 29,572	$ 27,516	$ 32,020	$ 33,570
5	Palo Verde - MultiMonths	$ 3,345	$ 3,271	$ 3,349	$ 3,427	$ 2,846	$ 2,932
6	RA Capacity	$ 1,357	$ 781	$ 1,166	$ 1,200	$ 1,783	$ 2,183
7	Ice Bear Installation Cost	$ -	$ 1,800	$ 1,500	$ 1,500	$ 1,500	$ 400
8	Ice Bear O&M Cost	$ -	$ 49	$ 74	$ 101	$ 129	$ 132
9	**Total Capacity Cost**	**$ 41,617**	**$ 35,547**	**$ 36,488**	**$ 34,549**	**$ 39,087**	**$ 40,026**
10							
11	**Other Fixed Cost**						
12	AB-32 Implementation	$ 261	$ 250	$ 250	$ 250	$ 250	$ 250
13	Amendment 60 Settlement	$ -	$ -	$ -	$ -	$ -	$ -
14	Contingency Generating Plants	$ 2,200	$ 2,200	$ 2,200	$ 2,200	$ 2,200	$ 2,200
15	**Total Other Fixed Cost**	**$ 2,461**	**$ 2,450**	**$ 2,450**	**$ 2,450**	**$ 2,450**	**$ 2,450**
16							
17	**SONGs Cost**						
18	Professional Services	$ 125	$ 200	$ 200	$ 200	$ 200	$ -
19	Outside Legal Services	$ 500	$ 700	$ 700	$ 700	$ 700	$ -
20	Decommissioning Operations	$ 1,500	$ -	$ -	$ -	$ -	$ -
21	O&M - Maint/Repair	$ 2,300	$ 350	$ 350	$ 350	$ 350	$ -
22	Insurance Charges - Direct	$ 195	$ 195	$ 195	$ 195	$ 195	$ -
23	Decommissioning Fund Exp	$ 3,000	$ 1,500	$ 1,500	$ 1,500	$ 1,500	$ -
24	Taxes and Assessments	$ 600	$ 600	$ 600	$ 600	$ 600	$ -
25	Nuclear Fuel Purchases	$ -	$ -	$ -	$ -	$ -	$ -
26	Capital Costs Related to Decomm.	$ 561	$ -	$ -	$ -	$ -	$ -
27	**SONGS Extra Costs - Total**	**$ 8,781**	**$ 3,545**	**$ 3,545**	**$ 3,545**	**$ 3,545**	**$ -**

APPENDIX D

Power Resource Budget Projections: Primary Metrics
10 Yr Budget Report:2014-12-26 BatchId 901 - RPU Master Long Term
*****All Costs/Revenues in ($1000)*****

Line		FY 2014/2015	FY 2015/2016	FY 2016/2017	FY 2017/2018	FY 2018/2019	FY 2019/2020
28							
29	**Transmission Revenue (TRR)**	**$ (31,000)**	**$ (32,000)**	**$ (32,320)**	**$ (32,643)**	**$ (32,970)**	**$ (33,299)**
30							
31	**Transmission Cost**						
32	Mead-Adelanto	$ 3,190	$ 3,322	$ 3,309	$ 3,294	$ 3,284	$ 2,551
33	Mead-Phoenix	$ 302	$ 318	$ 318	$ 317	$ 317	$ 253
34	STS	$ 11,000	$ 12,000	$ 12,000	$ 12,000	$ 11,000	$ 12,333
35	NTS	$ 1,827	$ 1,681	$ 1,681	$ 1,681	$ 1,681	$ 1,681
36	SCE	$ 11,500	$ 13,450	$ 13,700	$ 13,900	$ 14,100	$ 14,300
37	SCE WDAT	$ 1,455	$ 1,300	$ 1,320	$ 1,340	$ 1,360	$ 1,380
38	LADWP Service Agreements	$ 1,374	$ 1,310	$ 1,330	$ 1,350	$ 1,370	$ 1,390
39	Budget Adj. c/o of Potential FERC/CAISO Settlement	$ 1,543					
40	**Subtotal**	**$ 32,191**	**$ 33,381**	**$ 33,658**	**$ 33,882**	**$ 33,112**	**$ 33,888**
41	ISO TAC Load	$ 23,986	$ 22,651	$ 24,840	$ 27,261	$ 29,265	$ 31,090
42	ISO Transmission Charges	$ 1,644	$ 1,644	$ 1,690	$ 1,720	$ 1,750	$ 1,780
43	**Subtotal**	**$ 25,630**	**$ 24,295**	**$ 26,530**	**$ 28,981**	**$ 31,015**	**$ 32,870**
44	**Total Transmission Cost**	**$ 57,821**	**$ 57,676**	**$ 60,188**	**$ 62,863**	**$ 64,127**	**$ 66,758**
45							
46	**Total Net Transmission Cost**	**$ 26,821**	**$ 25,676**	**$ 27,868**	**$ 30,220**	**$ 31,157**	**$ 33,459**

APPENDIX D

Power Resource Budget Projections: Primary Metrics
10 Yr Budget Report:2014-12-26 BatchId 901 - RPU Master Long Term
*****All Costs/Revenues in ($1000)*****

Line		FY 2014/2015	FY 2015/2016	FY 2016/2017	FY 2017/2018	FY 2018/2019	FY 2019/2020
47							
48	**Resource Energy (MWh)**						
49	BPA-II with all Financial Returns	101,220	42,750	0	0	0	0
50	Clearwater - MultiMonths	11,884	12,377	11,992	12,170	11,470	12,339
51	Hoover	35,623	35,620	35,623	34,266	33,839	33,836
52	IPP Detail - Emissions	878,520	812,683	842,720	836,630	812,763	824,445
53	Palo Verde - MultiMonths	92,868	93,214	93,045	92,840	92,967	93,459
54	RERC	39,289	33,063	38,919	43,721	39,728	43,122
55	Salton Sea (Renewable) - MultiMonths	350,323	341,019	441,903	443,060	510,792	596,718
56	Springs	258	217	249	318	258	257
57	DVL 20MW Solar Historical Gen	29,220	29,402	55,582	55,297	54,885	54,594
58	Silverado 20MW (no sim)	0	0	22,540	44,577	44,352	44,236
59	Tequesquite Solar 7MW (no sim)	0	7,635	14,863	14,752	14,679	14,647
60	WinTec	4,666	4,666	4,667	4,666	2,131	0
61	WKN	21,535	21,534	21,538	21,536	21,538	21,535
62	Cabazon Wind	38,586	71,523	71,365	71,349	71,381	71,525
63	First Solar 14MW (no sim)	0	21,402	41,580	41,372	41,165	41,070
64	Recurrent Columbia II Solar 11MW (no sim)	40,621	33,220	32,983	32,818	32,654	32,561
65	**Total Energy Generation (MWh)**	**1,644,614**	**1,560,325**	**1,729,569**	**1,749,372**	**1,784,603**	**1,884,343**

APPENDIX D

Power Resource Budget Projections: Primary Metrics
10 Yr Budget Report:2014-12-26 BatchId 901 - RPU Master Long Term
*****All Costs/Revenues in ($1000)*****

Line		FY 2014/2015	FY 2015/2016	FY 2016/2017	FY 2017/2018	FY 2018/2019	FY 2019/2020
66							
67	**Total Energy Cost (no CO2)**						
68	NETREVENUEBPAFIN - NETREVENUEBPAFIN	$ 5,471	$ 4,241	$ -	$ -	$ -	$ -
69	Clearwater - MultiMonths	$ 787	$ 484	$ 535	$ 582	$ 592	$ 659
70	Hoover	$ 399	$ 401	$ 403	$ 390	$ 387	$ 389
71	IPP Detail - Emissions	$ 19,863	$ 18,228	$ 18,894	$ 20,054	$ 20,660	$ 21,427
72	Palo Verde - MultiMonths	$ 1,156	$ 987	$ 1,015	$ 1,043	$ 1,064	$ 1,102
73	RERC	$ 2,780	$ 1,418	$ 1,943	$ 2,304	$ 2,276	$ 2,521
74	Salton Sea (Renewable) - MultiMonths	$ 24,801	$ 24,557	$ 32,293	$ 32,862	$ 38,517	$ 45,642
75	Springs	$ 25	$ 13	$ 18	$ 23	$ 21	$ 21
76	DVL 20MW Solar Historical Gen	$ 2,443	$ 2,458	$ 4,700	$ 4,746	$ 4,781	$ 4,827
77	Silverado 20MW (no sim)	$ -	$ -	$ 1,599	$ 3,176	$ 3,160	$ 3,152
78	Tequesquite Solar 7MW (no sim)	$ -	$ 621	$ 1,218	$ 1,227	$ 1,239	$ 1,255
79	WinTec	$ 263	$ 269	$ 276	$ 282	$ 130	$ -
80	WKN	$ 1,396	$ 1,430	$ 1,464	$ 1,499	$ 1,535	$ 1,572
81	Cabazon Wind	$ 2,288	$ 4,241	$ 4,232	$ 4,231	$ 4,233	$ 4,241
82	First Solar 14MW (no sim)	$ -	$ 1,471	$ 2,859	$ 2,844	$ 2,830	$ 2,824
83	Recurrent Columbia II Solar 11MW (no sim)	$ 2,843	$ 2,325	$ 2,308	$ 2,297	$ 2,285	$ 2,279
84	**Subtotal Generation Cost**	**$ 64,516**	**$ 63,145**	**$ 73,755**	**$ 77,559**	**$ 83,710**	**$ 91,910**
85	CAISO Energy Charges	$ 752	$ 3,343	$ 3,410	$ 3,478	$ 3,548	$ 3,619
86	CRR Auction Cost	$ 1,150	$ 1,500	$ 1,600	$ 1,700	$ 1,800	$ 1,900
87	**Subtotal Generation Cost**	**$ 66,418**	**$ 67,988**	**$ 78,765**	**$ 82,737**	**$ 89,058**	**$ 97,429**
88	Power - Forward Contract - Purchases	$ (60)	$ 752	$ 496	$ -	$ -	$ -
89	**Total Generation Cost**	**$ 66,358**	**$ 68,739**	**$ 79,262**	**$ 82,737**	**$ 89,058**	**$ 97,429**
90	*Note Above: Net Hedge Cost/(Revenue)						

APPENDIX D

Power Resource Budget Projections: Primary Metrics
10 Yr Budget Report:2014-12-26 BatchId 901 - RPU Master Long Term
*****All Costs/Revenues in ($1000)*****

Line		FY 2014/2015	FY 2015/2016	FY 2016/2017	FY 2017/2018	FY 2018/2019	FY 2019/2020
91							
92	**CO2 Emissions, Costs, and Revenues**						
93							
94	**CO2 Emissions (metric tons)**						
95	Clearwater - MultiMonths	6,088	6,339	6,158	6,248	5,882	6,331
96	IPP Detail - Emissions	804,702	744,398	771,910	766,332	744,471	755,171
97	RERC	20,163	16,982	19,983	22,432	20,391	22,136
98	Springs	192	162	185	237	192	191
99	BPA Import Energy	2,520	1,005	0	0	0	0
100	**Total Emissions**	**833,665**	**768,885**	**798,237**	**795,249**	**770,936**	**783,829**
101							
102	**CO2 Cost**						
103	Clearwater - MultiMonths	$ 91	$ 89	$ 93	$ 101	$ 101	$ 115
104	IPP Detail - Emissions	$ 12,071	$ 10,760	$ 11,928	$ 12,606	$ 12,992	$ 13,934
105	RERC	$ 302	$ 239	$ 302	$ 361	$ 349	$ 403
106	Springs	$ 3	$ 2	$ 3	$ 4	$ 3	$ 3
107	**Total CO2 Cost**	**$ 12,467**	**$ 11,091**	**$ 12,327**	**$ 13,072**	**$ 13,446**	**$ 14,456**
108							
109	**CO2 Allowances and Auction Revenues**						
110	CO2 Allowances (metric tons)	1,056,379	1,054,845	1,067,013	1,075,313	1,081,054	1,083,954
111	CO2 Allowances Available for Sale at Auction	222,714	285,960	268,776	280,063	310,118	300,125
112	CO2 Auction Floor Price ($/metric ton)	$ 11.46	$ 12.26	$ 13.12	$ 14.04	$ 15.02	$ 16.07
113	CO2 Auction Revenue (Calculated)	$ (2,552)	$ (3,506)	$ (3,526)	$ (3,932)	$ (4,658)	$ (4,824)
114	**CO2 Auction Revenue (Budgeted)**	**$ (4,000)**	**$ (4,154)**	**$ (4,100)**	**$ (4,100)**	**$ (4,100)**	**$ (4,100)**

Power Resource Budget Projections: Primary Metrics
10 Yr Budget Report:2014-12-26 BatchId 901 - RPU Master Long Term
*****All Costs/Revenues in ($1000)*****

Line		FY 2014/2015	FY 2015/2016	FY 2016/2017	FY 2017/2018	FY 2018/2019	FY 2019/2020
115							
116	**Wholesale CAISO Sales (MWh)**						
117	Total Energy Generation Sold into SP15	1,644,614	1,560,325	1,729,569	1,749,372	1,784,603	1,884,343
118							
119	**Wholesale CAISO Revenue**						
120	BPA-II with all Financial Returns	$ (4,627)	$ (2,145)	$ -	$ -	$ -	$ -
121	Clearwater - MultiMonths	$ (809)	$ (712)	$ (776)	$ (839)	$ (846)	$ (941)
122	Hoover	$ (2,033)	$ (1,820)	$ (1,964)	$ (2,011)	$ (2,054)	$ (2,139)
123	IPP Detail - Emissions	$ (40,495)	$ (33,397)	$ (37,645)	$ (39,824)	$ (40,225)	$ (42,342)
124	Palo Verde - MultiMonths	$ (3,940)	$ (3,496)	$ (3,790)	$ (4,022)	$ (4,168)	$ (4,373)
125	RERC	$ (3,102)	$ (2,234)	$ (2,977)	$ (3,531)	$ (3,436)	$ (3,793)
126	Salton Sea (Renewable) - MultiMonths	$ (14,912)	$ (12,774)	$ (18,083)	$ (19,293)	$ (22,948)	$ (28,073)
127	Springs	$ (26)	$ (19)	$ (25)	$ (33)	$ (29)	$ (30)
128	DVL 20MW Solar Historical Gen	$ (1,230)	$ (1,155)	$ (2,433)	$ (2,582)	$ (2,660)	$ (2,756)
129	Silverado 20MW (no sim)	$ -	$ -	$ (962)	$ (2,086)	$ (2,153)	$ (2,235)
130	Tequesquite Solar 7MW (no sim)	$ -	$ (301)	$ (653)	$ (690)	$ (713)	$ (741)
131	WinTec	$ (193)	$ (171)	$ (185)	$ (198)	$ (98)	$ -
132	WKN	$ (889)	$ (789)	$ (854)	$ (914)	$ (949)	$ (992)
133	Cabazon Wind	$ (1,498)	$ (2,644)	$ (2,867)	$ (3,054)	$ (3,164)	$ (3,313)
134	First Solar 14MW (no sim)	$ -	$ (829)	$ (1,811)	$ (1,924)	$ (1,986)	$ (2,067)
135	Recurrent Columbia II Solar 11MW (no sim)	$ (1,688)	$ (1,334)	$ (1,432)	$ (1,519)	$ (1,569)	$ (1,630)
136	**Total Generation Revenue**	**$ (75,444)**	**$ (63,819)**	**$ (76,455)**	**$ (82,521)**	**$ (86,997)**	**$ (95,423)**

APPENDIX D

Power Resource Budget Projections: Primary Metrics
10 Yr Budget Report:2014-12-26 BatchId 901 - RPU Master Long Term
*****All Costs/Revenues in ($1000)*****

Line		FY 2014/2015	FY 2015/2016	FY 2016/2017	FY 2017/2018	FY 2018/2019	FY 2019/2020
137							
138	**Gross Load (includes internal gen.) in MWh**						
139	GENERATIONLOAD - Load @ Generation	2,329,483	2,372,618	2,400,287	2,434,984	2,471,333	2,514,472
140	TOTALLOADCOSTS - Total Load Cost	$ 102,889	$ 92,534	$ 101,552	$ 109,557	$ 115,410	$ 122,463
141							
142	**Net CAISO Energy Position**						
143	Net Market Purchases or (Sales) in MWh	684,869	812,292	670,718	685,612	686,731	630,129
144	Net Cost of Market Purchases or (Sales)	$27,445	$28,715	$25,097	$27,036	$28,413	$27,040
145	Market Contingency Reserve	$0	$4,266	$4,574	$4,837	$4,731	$4,005
146							
147	**Gas Burn (MMBtu)**						
148	Clearwater - MultiMonths	160,315	119,225	115,834	117,521	110,640	119,077
149	RERC	530,942	319,424	375,868	421,937	383,539	416,372
150	Springs	5,049	3,039	3,480	4,450	3,616	3,599
151	**Total Burn**	**696,306**	**441,688**	**495,182**	**543,908**	**497,796**	**539,048**
152							
153	**Fuel Cost**						
154	Clearwater - MultiMonths	$ 757	$ 453	$ 505	$ 551	$ 563	$ 628
155	RERC	$ 2,564	$ 1,236	$ 1,729	$ 2,063	$ 2,057	$ 2,284
156	Springs	$ 24	$ 12	$ 17	$ 22	$ 20	$ 20
157	Gas - Forward Contract - Purchases	$ 499	$ 1,690	$ 291	$ -	$ -	$ -
158	**Subtotal**	**$ 3,844**	**$ 3,391**	**$ 2,542**	**$ 2,636**	**$ 2,640**	**$ 2,932**
159	VOMCosts - VOM Costs	$ 247	$ 214	$ 245	$ 272	$ 248	$ 269
160	**Total Fuel Cost**	**$ 4,091**	**$ 3,604**	**$ 2,787**	**$ 2,909**	**$ 2,889**	**$ 3,201**
161	*Note Above: Net Hedge Cost/(Revenue)						
162							

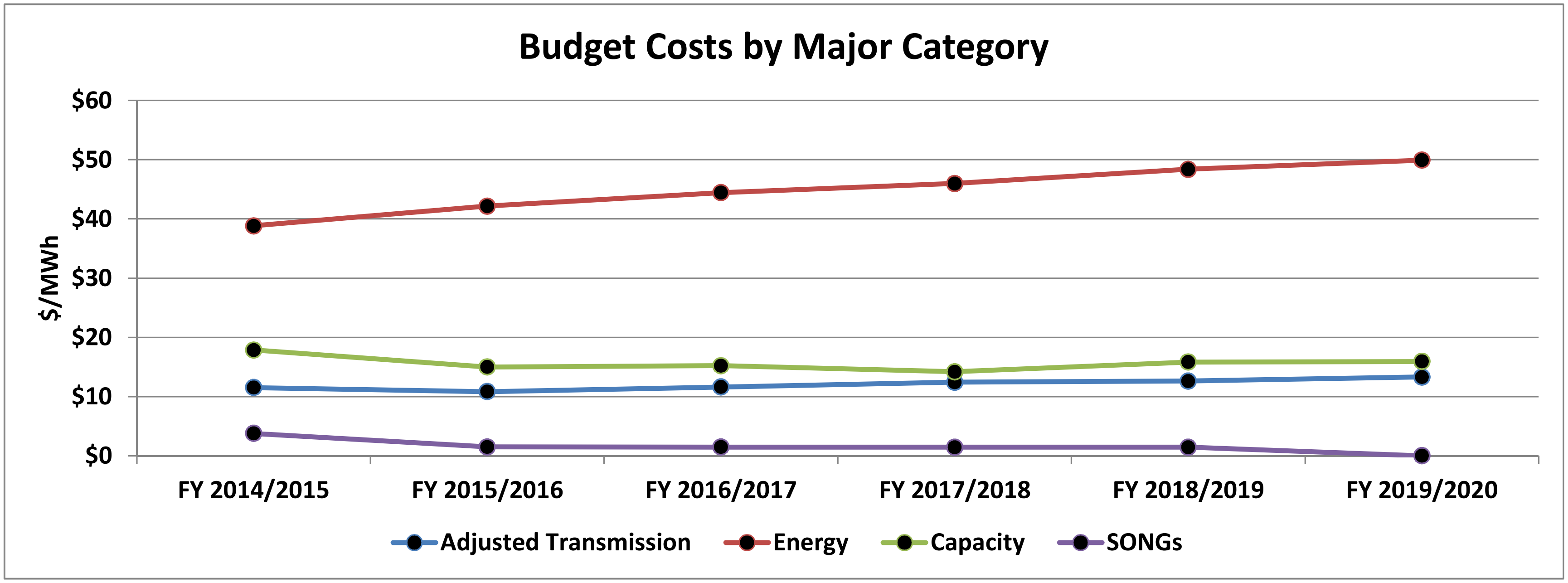
APPENDIX D

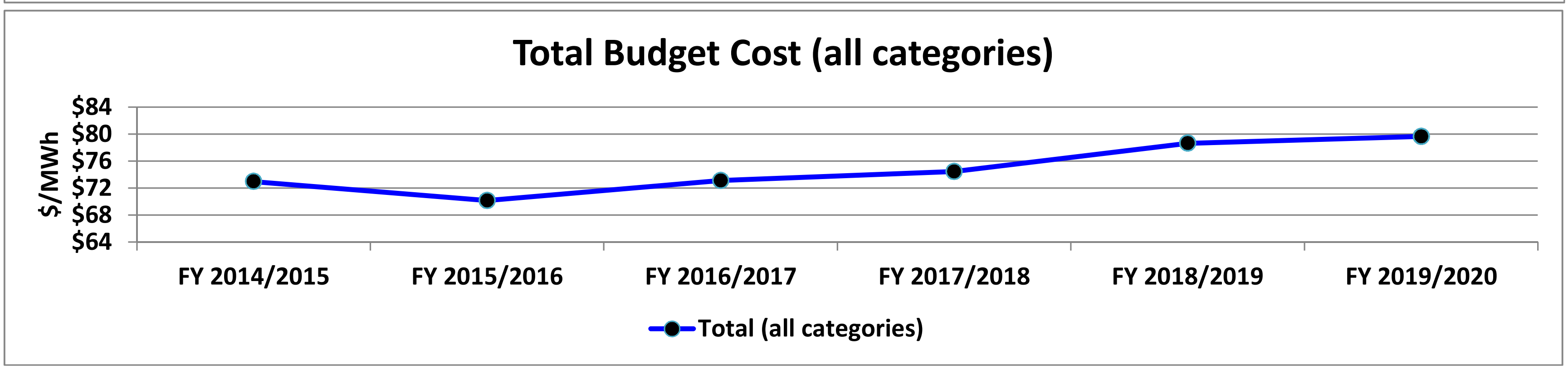
Power Resource Budget Projections: Primary Metrics
10 Yr Budget Report:2014-12-26 BatchId 901 - RPU Master Long Term
*****All Costs/Revenues in ($1000)*****

Line		FY 2014/2015	FY 2015/2016	FY 2016/2017	FY 2017/2018	FY 2018/2019	FY 2019/2020
163	Summary						
164	Gross Costs	$ 204,983	$ 202,628	$ 211,896	$ 218,017	$ 231,411	$ 237,708
165	Gross Revenue	$ (35,000)	$ (36,154)	$ (36,420)	$ (36,743)	$ (37,070)	$ (37,399)
166	Net Costs	$ 169,983	$ 166,474	$ 175,476	$ 181,274	$ 194,341	$ 200,309
167							
168	Summary						
169	Transmission	$ 57,821	$ 57,676	$ 60,188	$ 62,863	$ 64,127	$ 66,758
170	Energy	$ 90,459	$ 100,020	$ 106,682	$ 111,974	$ 119,562	$ 125,542
171	Capacity	$ 41,617	$ 35,547	$ 36,488	$ 34,549	$ 39,087	$ 40,026
172	SONGS	$ 8,781	$ 3,545	$ 3,545	$ 3,545	$ 3,545	$ -
173	GHG Regulatory Fees	$ 261	$ 250	$ 250	$ 250	$ 250	$ 250
174	Amendment 60 Settlement	$ -	$ -	$ -	$ -	$ -	$ -
175	Contingency Generating Plants	$ 2,200	$ 2,200	$ 2,200	$ 2,200	$ 2,200	$ 2,200
176	Gas Burns + Net Hedge Cost or (Revenue)	$ 3,844	$ 3,391	$ 2,542	$ 2,636	$ 2,640	$ 2,932
177	SUBTOTAL COST	$ 204,983	$ 202,628	$ 211,896	$ 218,017	$ 231,411	$ 237,708
178	CO2 Allowance Auction Revenue	$ (4,000)	$ (4,154)	$ (4,100)	$ (4,100)	$ (4,100)	$ (4,100)
179	TRR Revenue	$ (31,000)	$ (32,000)	$ (32,320)	$ (32,643)	$ (32,970)	$ (33,299)
180	SUBTOTAL REVENUE	$ (35,000)	$ (36,154)	$ (36,420)	$ (36,743)	$ (37,070)	$ (37,399)
181							
182	TOTAL	$ 169,983	$ 166,474	$ 175,476	$ 181,274	$ 194,341	$ 200,309
183							
184	Summary (Cost/Gross Load)						
185	Adjusted Transmission	$ 11.51	$ 10.82	$ 11.61	$ 12.41	$ 12.61	$ 13.31
186	Energy	$ 38.83	$ 42.16	$ 44.45	$ 45.99	$ 48.38	$ 49.93
187	Capacity	$ 17.87	$ 14.98	$ 15.20	$ 14.19	$ 15.82	$ 15.92
188	SONGs	$ 3.77	$ 1.49	$ 1.48	$ 1.46	$ 1.43	$ -
189	Total (all categories)	$ 72.97	$ 70.16	$ 73.11	$ 74.45	$ 78.64	$ 79.66

Power Resource Budget Projections: Primary Metrics
10 Yr Budget Report:2014-12-26 BatchId 901 - RPU Master Long Term
*****All Costs/Revenues in ($1000)*****

Line		FY 2014/2015	FY 2015/2016	FY 2016/2017	FY 2017/2018	FY 2018/2019	FY 2019/2020





APPENDIX E: RPU debt-service & all-other cost assumptions and calculations.

New Bond Issuance Assumptions							
Timing	2016	2019	2022	2025	2028	2031	2034
Par Amount	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000
Interest Rate	5%	5%	5%	5%	5%	5%	5%
Maturity	30	30	30	30	30	30	30
Structure	Level	Level	Level	Level	Level	Level	Level

	For Period Ending October 1									Adjusted to Calendar Year Basis		
Year	Existing Debt Service Requirment	New Debt Service	New Debt Service	New Debt Service	New Debt Service	New Debt Service	New Debt Service	New Debt Service	Total Debt Service Requirement	Total Debt Service	Total Cost from Other Budget Categories	Grand Total All Other Budget Costs
2014	$44,629,724								$44,629,724	**$44,710,937**	**$58,128,000**	**$102,838,937**
2015	$44,954,574								$44,954,574	**$45,111,633**	**$58,453,000**	**$103,564,633**
2016	$41,679,724	$3,903,086							$45,582,810	**$45,565,723**	**$58,858,000**	**$104,423,723**
2017	$41,611,374	$3,903,086							$45,514,460	**$45,520,793**	**$60,027,330**	**$105,548,123**
2018	$41,636,706	$3,903,086							$45,539,792	**$46,515,114**	**$61,227,877**	**$107,742,990**
2019	$41,634,907	$3,903,086	$3,903,086						$49,441,079	**$49,441,682**	**$62,452,434**	**$111,894,116**
2020	$41,637,318	$3,903,086	$3,903,086						$49,443,490	**$49,430,133**	**$63,701,483**	**$113,131,616**
2021	$41,583,888	$3,903,086	$3,903,086						$49,390,060	**$50,354,475**	**$64,975,512**	**$115,329,988**
2022	$41,538,462	$3,903,086	$3,903,086	$3,903,086					$53,247,720	**$53,232,435**	**$66,275,023**	**$119,507,458**
2023	$41,477,320	$3,903,086	$3,903,086	$3,903,086					$53,186,578	**$53,170,994**	**$67,600,523**	**$120,771,517**
2024	$41,414,983	$3,903,086	$3,903,086	$3,903,086					$53,124,241	**$54,084,650**	**$68,952,534**	**$123,037,183**
2025	$41,353,530	$3,903,086	$3,903,086	$3,903,086	$3,903,086				$56,965,874	**$56,942,975**	**$70,331,584**	**$127,274,559**
2026	$41,261,933	$3,903,086	$3,903,086	$3,903,086	$3,903,086				$56,874,277	**$56,859,468**	**$71,738,216**	**$128,597,684**
2027	$41,202,694	$3,903,086	$3,903,086	$3,903,086	$3,903,086				$56,815,038	**$57,769,922**	**$73,172,980**	**$130,942,903**
2028	$41,119,143	$3,903,086	$3,903,086	$3,903,086	$3,903,086	$3,903,086			$60,634,574	**$60,613,652**	**$74,636,440**	**$135,250,092**
2029	$41,035,457	$3,903,086	$3,903,086	$3,903,086	$3,903,086	$3,903,086			$60,550,888	**$60,528,492**	**$76,129,169**	**$136,657,661**
2030	$40,945,875	$3,903,086	$3,903,086	$3,903,086	$3,903,086	$3,903,086			$60,461,306	**$61,414,586**	**$77,651,752**	**$139,066,338**
2031	$40,855,912	$3,903,086	$3,903,086	$3,903,086	$3,903,086	$3,903,086	$3,903,086		$64,274,429	**$64,248,552**	**$79,204,787**	**$143,453,340**
2032	$40,752,407	$3,903,086	$3,903,086	$3,903,086	$3,903,086	$3,903,086	$3,903,086		$64,170,924	**$64,144,818**	**$80,788,883**	**$144,933,701**
2033	$40,647,986	$3,903,086	$3,903,086	$3,903,086	$3,903,086	$3,903,086	$3,903,086		$64,066,503	**$65,015,022**	**$82,404,661**	**$147,419,683**
2034	$40,538,978	$3,903,086	$3,903,086	$3,903,086	$3,903,086	$3,903,086	$3,903,086	$3,903,086	$67,860,581			
									Total	**$1,084,676,056**	**$1,376,710,187**	**$2,461,386,243**
									Avg. Ann. GR	**1.89%**	**1.76%**	**1.82%**

APPENDIX F

F.1 IPP CC Gas Curve Assumptions

SInce the IPP NGCC plant will be located in Utah, natural gas for the IPP NGCC plant is assumed to be sourced from Utah and priced using a forward pricing curve at a natural gas trading hub in the region. The particular forward pricing curve we considered in our IPP NGCC analysis is for the NWP-Rockies hub. This forward curve is published on ICE and is representative of the Rocky Mountain Region.

Currently, the forward curve for the SoCal Citygate hub is the only natural gas forward curve being harvested in the Ascend Portfolio Modeling Software. Therefore, to study the cost impact of the IPP NGCC, we made a manual adjustment to our SoCal Citygate forward curve to reflect the average pricing differential between the SoCal Citygate and NWP-Rockies forward curves. This pricing differential is highlighted in Figure F.1 and Table F.1, respectively.

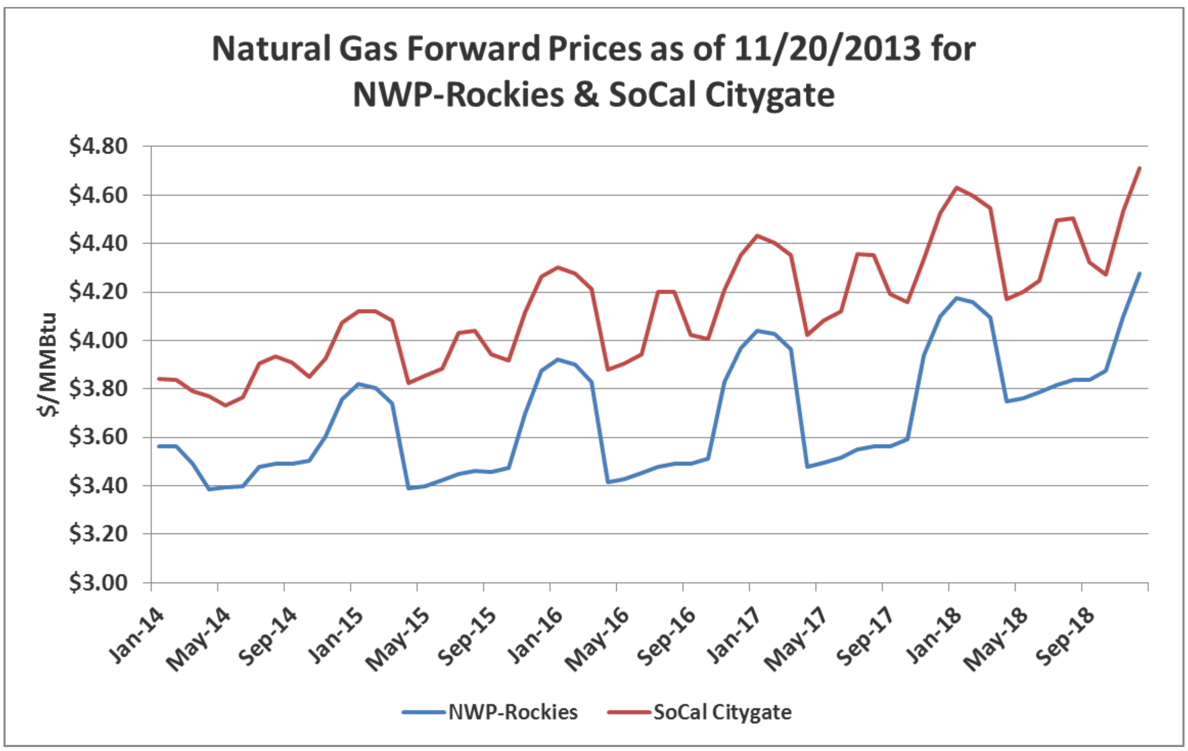


Figure F.1. NWP-Rockies and SoCal Citygate forward curves as of 11/20/2013.

As shown by these data, there is a considerable price differential between the NWP-Rockies and SoCal Citygate forward curves, with the forward prices for the NWP-Rockies hub being less than those for SoCal Citygate. In particular, between 2014 and 2018, the NWP-Rockies forward prices average about $0.46/mmBtu less than SoCal Citygate. When considering only the outer years (2016 – 2018), the average forward price differential increases and settles to about $0.50/mmBtu. Given that the IPP NGCC is assumed to come online in 2021 and 2025 (depending on the IRP scenario), we reduced our entire SoCal Citygate forward curve by the $0.50/mmBtu average seen in the outer years. The end result of this adjustment is shown in Figure F.2 below.

Table F.1. Annual NWP-Rockies and SoCal Citygate forward pricing differential as of 11/20/2013.

Year	NWP-Rockies ($/mmBtu)	SoCal Citygate ($/mmBtu)	Differential ($/mmBtu)
2014	3.51	3.86	-0.35
2015	3.58	4.02	-0.43
2016	3.64	4.13	-0.48
2017	3.73	4.28	-0.54
2018	3.95	4.44	-0.49
Average (2014-2018)	**3.68**	**4.14**	**-0.46**
Average (2016-2018)	**3.78**	**4.28**	**-0.50**

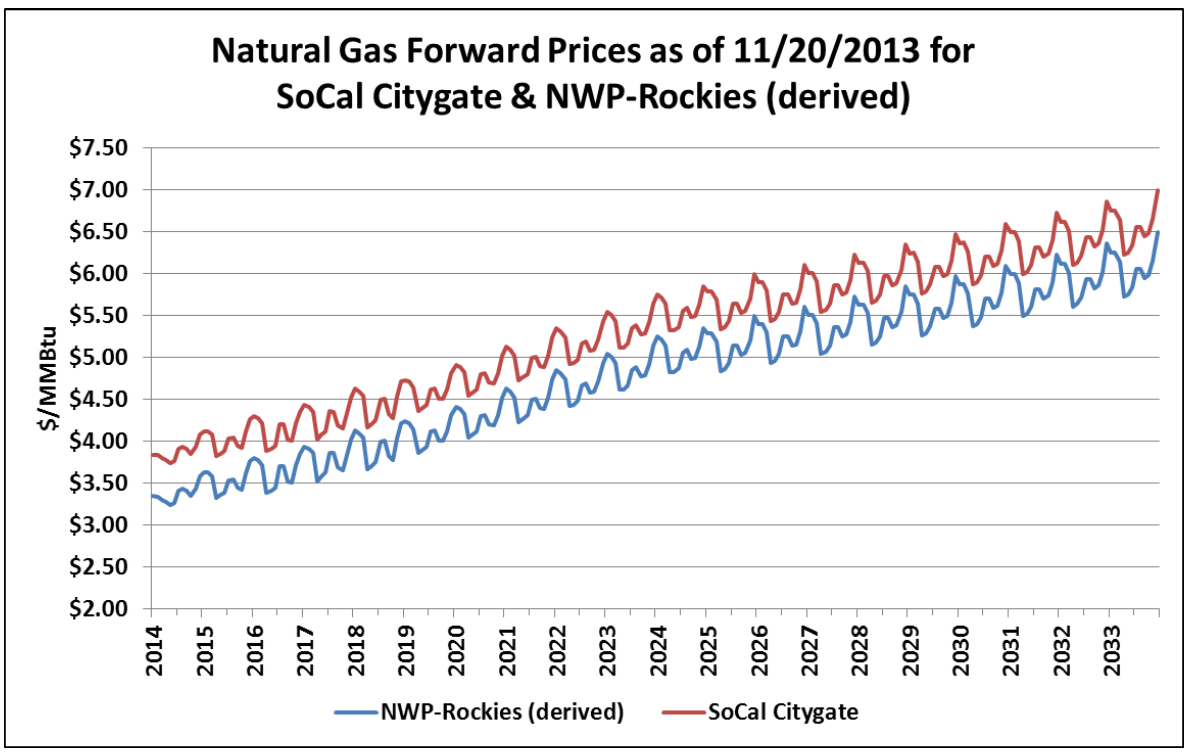


Figure F.2. Derived NWP-Rockies forward curve versus SoCal Citygate forward curve.