SAN JOSE CLEAN ENERGY
A Program of the City of San José

San José Clean Energy

BUSINESS PLAN ASSESSMENT

November 16th, 2021

Contents

List of Tables

Executive Summary

Project Overview

Deloitte & Touche, LLP ("Deloitte" or "we") is pleased to provide the following report in response to San José Clean Energy's ("SJCE" or "you" or "the Department") request for assistance in developing a Draft Business Plan and Strategy (Service Order No. 001 under AC Contract No. OC-000793-001). We assembled a team of energy industry specialists who, collectively, bring experience in energy commodity markets, risk management, compliance, modeling, and strategy in order to address the specific questions brought forth by SJCE.

Deloitte was engaged to work with SJCE staff to address three primary tasks, as described below. Task 1 focused on reviewing certain elements from the Department's Community Choice Aggregation ("CCA") Business Plan (the "Plan") which was originally developed in February 2017. This review included providing high level discussion and analysis as to the conditions that may have changed, actual results and performance as compared to original projections, and highlighting major differences that have evolved in the market from 2017 as compared to today. Deloitte was asked to review assumptions that were elements of the 2017 report and provide comparisons to actual results. Part of the review also included re-visiting the risks that were identified in 2017, including rates, market rules, regulatory risks and liability to the general fund.

Task 2 required Deloitte to work with SJCE staff to complete more quantitative effort, as compared to Task 1, in order to assess certain energy industry trends and the Department's energy market analysis. The output of this task is leveraged to inform a proposed strategic plan framework that forms the basis of Task 3. Task 2 involved a review of the Department's projections of two important factors, the Power Charge Indifference Adjustment ("PCIA") and Pacific Gas & Electric's ("PG&E") generation rate for the years 2022 – 2025, and an assessment of the Department's projection of expected COVID-19 debt relief. The balance of Task 2 included discussion and review of various market trends, including the potential financial impacts of the identified trends and the projections noted above. Working with the Department staff, the Deloitte team leveraged the SJCE existing models to evaluate various scenarios and estimate the potential impacts.

Task 3 required that Deloitte team to work with the Department staff to lay out an initial Strategic Plan Framework to help the department accomplish the following objectives: (1) Ensure SJCE's Financial Stability, (2) Accelerate clean energy goals , and (3) Improve Organizational Effectiveness.

The Department is working to develop and present to the City of San José ("the City') a new five-year business plan. Beginning in late September, Deloitte conducted interviews with 25 people, primarily from the City and the Department, as identified in Appendix B. In addition to the personnel interviews, Deloitte received and reviewed a number of documents, reports, data sources, and staff analyses as shown in Appendix A. We held working sessions with key SJCE staff in order to advance the completion of the project in a collaborative manner and was aligned with the Department's expectations. Given the short duration of the project, approximately six weeks, the depth of quantitative analysis was necessarily limited in order to meet the timeline required to support discussions with the City.

Results Summary

Overall, the 2017 Plan appears to be a well thought out document that considers the relevant elements we would expect to see among peer organizations. It enumerated and examined a number of key risks associated with establishing SJCE, including potential changes in the PCIA and underlying power costs. The Plan also included sensitivity analysis across various inputs. Given the regulatory requirements and market information that was readily available at that point in time, the analysis and recommendations in the plan were reasonable.

However, in some cases the plan underestimated the likelihood of possible extreme outcomes. Even in the SJCE Worse Case or "perfect storm" scenario in the 2017 Plan (low customer participation, high SJCE power supply costs, and PCIA charges), the projected impact was less than what was actually realized. Since the 2017 plan, increases in the PCIA and power costs more than offset the better than expected customer participation that SJCE was able to achieve.

Compared to the plan, the launch of SJCE service to all customers was delayed by eight months, which then coincided with market and regulatory changes that resulted in SJCE's financial position to be more constrained than planned. At the same time, PG&E's generation rate remained relatively stable, impacting competitiveness of SJCE. The market and regulatory changes of note included:

- PCIA methodology change and resulting increases in PCIA
- Higher Brown Power ("BP") costs because of a variety of market factors
- Higher Resource Adequacy ("RA") Costs resulting from additional regulatory action and constraints on capacity
- Higher Renewable Energy Credit ("REC") costs

Looking forward, the PCIA is expected to moderate from $0.04/kWh in 2021 to lower levels on average overage 2022-2025, with a small increase in 2023 from 2022 before trending lower again in 2024 and 2025. SJCE is expecting to collect 65% of its overdue residential customer balances resulting from COVID-19 under the state program. Forward power prices as reflected by NP15 have increased throughout 2021 as natural gas prices have also increased. The forwards for 2022 delivery have come off of their highs of the year, while those for 2023 to 2025 remain near recent highs. That said, in October 2021, the overall NP15 curve exhibits declining overall prices with delivery further into the future. As of October 13, 2021, Peak NP15 prices for 2022 were $72/MWh, while 2023 delivery was only $56/MWh, with 2024 and 2025 lower still, averaging $43/MWh. The prices are based on the observations on that as-of-date, and the overall price curve can mode over time and even day-to-day or intraday.

Scenario cases were run using a PCIA model available to SJCE and the SJCE financial models to evaluate potential impacts from shifts in the market price benchmarks (“MPB”) for BP and RA. Modeled PCIA and PG&E bundled generation rates were relatively more sensitive to shifts in MPB BP than to shifts in MPB RA, as was SJCE total revenue.

Advancements in renewable technology and customer demand for renewables are going hand in hand in driving towards accelerating the decarbonization of the power market. SJCE should continue to actively participate in various stakeholder forums to continue to refine their investment strategies including consideration of various storage technologies and green hydrogen. Concurrently, SJCE should look for further ways to engage their customers and industry groups to identify technologies, including demand side management and distributed energy resources (“DERs”), which SJCE can help meet their sustainability goals.

From a regulatory perspective, SJCE should continue to advocate their position in various proceedings at the California Public Utility Commission (“CPUC”) related to PCIA, RA and other rule making that impacts CCA. SJCE should continue to collaborate with California Community Choice Association (“CalCCA”) in proposing legislative action such as Senate Bill (“SB”) 612.

Based on this analysis, from a strategic perspective, the Department should consider prioritizing a number of actions to enhance financial stability by increasing reserves and add capabilities in specific areas. To put SJCE’s financial footing on firmer ground, the Department should consider moving to cost of service rates, increasing their credit capacity, and limiting additional program spending in the near term. To enable this stronger financial position, additional steps should also be considered. These could include targeted increases in staffing and infrastructure in the market risk area to be able to support the evaluation and possible execution of additional risk mitigation or hedging strategies. With this platform, the Department should enhance their current scenario analysis, leveraging both historical price data as well as models of forward price curves, which can help SJCE evaluate the potential risks and related benefits of hedging strategies. Improved scenario analysis and modeling capabilities can help the Department develop, evaluate, and implement longer-term risk management and response strategies.

Task 1: SJCE Business Plan Review

The City commissioned EES Consulting, Inc. to prepare a Plan that evaluated the viability of a potential CCA, which was delivered in February 2017. The San José City Council unanimously voted to create San José Clean Energy, the city's CCA, in May 2017. After several months serving City accounts beginning November 2018, SJCE launched service to most of the City in February 2019. Projections about various aspects of the CCA's business such as revenues, power supply costs, administrative costs, electric loads, future retail rates, Greenhouse Gas ("GHG") reductions, customer participation were made in the Plan. The purpose of this assessment is to evaluate SJCE's actual performance with respect to the projections in the Plan.

Task 1 Key Takeaways

Here is a summary of the key takeaways from Task 1 which are discussed in more detail in the upcoming sub-sections:

- The City set up SJCE as a single jurisdiction CCA with a full staff scenario.
- The overall level of staff appeared to be underestimated in the Plan, and the Department does not appear to be sufficiently staffed to effectively run its operations.
- Although SJCE started service later than expected based on the Plan, once all customers were enrolled, load appears to be in line with expectations. The level of opt-outs has been lower than planned.
- Power costs inclusive of brown power, RECs and RA have been higher than planned.
- The Department has been able to deliver a significantly more renewable and carbon-free product when compared to PG&E.
- With this higher renewable and carbon-free energy mix, the Department has been able to reduce GHG emissions above the PG&E RPS plan.
- Non-power supply costs have generally been in line with the Plan so far; however, we expect those to increase as the Department continues to staff up in relevant areas.
- Higher power supply costs, lower PG&E generation rates and large increases in the PCIA put pressure on the Department's financial position given the Department strove to maintain a discount or parity with PG&E
- SJCE has tried to shore up its financial position by raising rates and by borrowing through the City's commercial paper program. SJCE's default rate is now at a premium to PG&E.

SJCE's 2017 plan contains four different scenarios with varying levels of renewable resources. They are:

- ***Match PG&E***: SJCE will match PG&E on both renewable and GHG-free energy sources
- ***PG&E + 10%:*** SJCE will exceed PG&E's renewable and GHG-free generation by 10%
- ***PG&E + 20%:*** SJCE will exceed PG&E's renewable and GHG-free generation by 20%
- ***100% Renewable:*** SJCE will supply 100% of retail load with renewable power

In the sections below, only the first two scenarios (Match PG&E, PG&E + 10%) are used for comparison purposes.

1.1 Governance and Operational Structure

SJCE's current operating and governance structure compared to the 2017 projections

1.1.1 Governance structure

The City elected a single jurisdiction model for SJCE versus joining an existing Joint Powers Authority ("JPA") or starting a new JPA. The tradeoffs associated with this decision were properly described in the 2017 plan. The single jurisdiction model has given SJCE more control over decision making and resulting in both benefits and risks. From a benefits perspective, SJCE has more control over rate making and can drive specific programs to suit their customers directly. From a risk perspective, risks are more concentrated under this governance structure (e.g., impact of energy procurement decisions apply directly to SJCE rather than being shared by multiple parties and the costs of standing up of a full energy transacting organization are also borne by SJCE and the City of San José rather than multiple parties). If the City had pursued joining a JPA, they would have to share decision making resulting in additional consensus building and potentially reducing options on rates and programs. Given San José's size and number of customers, the number of votes on the JPA Board would also be important in determining the City's voice within the JPA.

In addition, by being a Department within the City of San José, SJCE can access shared city services such as Human Resources ("HR") and Information Technology ("IT"). SJCE also benefits from easier access to credit by leveraging the City's credit facilities and more favorable collateral terms from the California Independent System Operator ("CAISO") based on the City's credit rating.

1.1.2 Operational structure

Once the City of San José elected the single jurisdiction model (i.e., opting for more control over the CCA's operations), it naturally followed that a full staff scenario would be put into place rather than the minimum staff scenario. Both options were described in the 2017 Plan; (i) the full staff scenario was about hiring sufficient staff in-house to manage SJCE's operations, and (ii) the minimum staff scenario was where the City hires minimal staff to oversee third party contracts and then outsources the remaining functions of the CCA through consulting arrangements. The minimum staff scenario has been rarely used by existing CCAs.

The full staffing scenario within the 2017 Plan assumed an end-state organization of 19 employees to run the Department. Based on our experience and the interviews we held with various SJCE stakeholder, the resource count appears to have been underestimated significantly although the overall non-power costs that the proforma estimated in the 2017 plan is close to current burn rate of the Department with 34 full time employees. As discussed later in the report, it is recommended that the Department further build and enhance capabilities in market risk management to be able to manage both opportunities and risks associated with SJCE operations more holistically.

1.2 Load

This section aims to compare SJCE's load, customer accounts served in 2018-2020 and participation rates to 2017 projections.

SJCE's actual load came closer into sync with the projections in the Plan during the latter half of 2019 when most customers had been enrolled in service. The actual load was closer to projections as SJCE enrolled more customers and opt-outs turned out to be lower than expected. The Plan assumed that SJCE would first provide service only to the City's municipally owned facilities starting early in 2018, then expand to residential and small commercial customers in June of 2018, and finally offer service to all customers by November 2018. The actual launch to municipal facilities was delayed to September 2018. In February 2019, SJCE started offering services to residential, medium and large commercial customers and expanded to small commercial customers in June of 2019. This delay in the start of service impacted the realization of revenue and accumulation of reserves when compared to the plan.

SJCE's Load, customer accounts and participation rates are summarized in Table 1. In 2019, SJCE's load was 16% lower than the projected load and in 2020, it was 3% lower than projections. 2017 estimates assumed participation rates of 85% and 75% for residential and non-residential customers. SJCE outperformed the projections in terms of customer participation.

Participation rates are based on the total number of customers in SJCE's territory vs. those subscribed to SJCE service. Participation rates were 91% and 96% in 2019 and 2020 respectively, which represented 7 percentage points more than the Plan in 2019 and 12 percentage points ahead of Plan in 2020. The participation rate increased from 2019 to 2020 as SJCE completed its final mass enrollment of customers, residential NEM customers, in 2020 and finishing in early 2021.

The Opt-out rate presented in Table 1 is a cumulative rate at the end of the year. This metric is based on the number of customers that decline SJCE service.

Table 1: SJCE Projected and Actual load for 2018-20

	Projected			Actual			
	Load (GWh)	**Customer Accounts**	**Participation Rate**	**Load (GWh)**	**Customer Accounts**	**Participation Rate**	**Opt-out %**
2018	1,611	172,547	84%				-
2019	4,120	300,317	84%	3458	326,630	91%	1.59%
2020	4,149	302,420	84%	4013	345,506	96%	2.14%

1.3 Power Supply Costs

This section aims to compare SJCE's actual power supply costs in 2018-2020, including the cost of conventional energy ("Brown Power"), RA, GHG-free, and RPS resources to 2017 projections.

SJCE's projected retail load and projected power mix for various scenarios were used to obtain the load for Renewable Portfolio Standard ("RPS") power, GHG free power and Non-renewable (or Brown) power categories. Projected costs in dollars per megawatt-hour ("$/MWh") were taken from the plan for various resources such as wind, solar, local renewables, natural gas fired, and market Power Purchase Agreements ("PPAs"). Specific assumptions made in the plan regarding sourcing renewable and non-renewable energy in percentages were used to estimate energy costs in $/MWh. Brown Power costs were calculated by separating implied unbundled RECs costs from Renewable energy costs. Other costs related to power supply such as Ancillary services, Congestion, Scheduling and RA were also extracted. Non-power supply costs in plan include Staffing, Administrative, PG&E billing and metering, and Consultant costs.

SJCES's projected total power supply costs in $/MWh for two scenarios are compared to the actual total power supply costs in the same units and are summarized in Table 2.

Note that the total power cost in $/MWh summarized in Table 2 is not necessarily a sum of Energy, REC, and RA, as RECs only cover a part of the load (renewable) and not the entire load. So, the cost of RECs in $/MWh cannot be added directly to the other costs to obtain total cost. Cost of unbundled RECs was separated from the Energy costs in the projections, in order to keep them consistent with actuals.

Table 2: SJCE's total power supply costs (Energy + REC + RA + RA Penalty) in $/MWh

	Projected		Actual
	Match PG&E	**PG&E + 10%**	
2018	55.47	56.54	57.90
2019	56.87	57.78	70.06
2020	58.25	58.99	70.38

SJCE's actual and projected power supply costs are compared in Table 3. Projected costs for 'Match PG&E' scenario are subtracted from the actual costs for comparison. Unit costs ($/MWh) are rounded to one decimal place and total costs (in Million $) are rounded to nearest integer for convenience.

Table 3: SJCE's Actual unit power supply costs (vs) Projected unit power supply costs

	Actual costs above Projected costs in %	
	Match PG&E	**PG&E + 10%**
2018	7	4
2019	26	23
2020	23	21

The comparisons below, between actual SJCE power supply costs and 'Match PG&E' scenario of projections, are performed only for 2019 and 2020.

In 2019, unit brown power prices were moderately above projections. Similarly, for 2020, the actual unit brown power costs were above forecasted unit costs. The increase in load in 2020 resulted in increased total costs in spite of the decrease in unit brown power costs between 2019 and 2020. The reasons for increasing power costs are discussed in detail in section 1.8. The actual unit cost of unbundled RECs was very close to projected unit costs in 2019. In the year 2020, the unit costs were significantly above the projections in 2017 plan. Due to regulatory rule changes in 2018, SJCE shifted to purchasing increased number of higher quality (bundled) Product Content Category ("PCC") 1 and PCC2 RECs as PCC3 RECs were no longer being counted as Renewables on the Power Content Label ("PCL"). This had a significant effect on the increased unit costs. Both in 2019 and 2020, actual unit RA costs were significantly greater than projected costs.

Total power supply costs which include Brown power, REC, RA costs were underestimated for all three years. The actual unit power supply costs are compared with projections and are detailed in Table 3. Unit power supply costs were moderately greater than projections for both the scenarios. As mentioned above, increase in actual load is the reason behind increased total power supply costs between 2019 and 2020 in spite of the decrease in unit costs.

Power costs were consistently higher compared to the Plan for brown power, RA, and RECs over 2019 and 2020.

Multiple external forces contributed to higher power costs compared to the Plan, some resulting in short term impacts and some long term. Below is a high-level summary of some of these factors:

- ***Enbridge Pipeline Explosion:*** As SJCE was initiating power procurement activities prior to its' launch, a section of Enbridge's T-South pipeline in British Columbia exploded in October 2018. This not only disrupted supply in Canada but also severely impacted natural gas availability in Western USA[1].
- ***Increased wildfire risk and incidence****:* The increase in the number and severity of wildfires in California and surrounding areas over the last three years has resulted in increased volatility in power prices because of potential supply disruptions.
- ***Rolling blackouts in 2020 due to heat storm:*** The heat storm in 2020 had California experience four of its five hottest August days in the last 35 years. This resulted in a small fraction of customers experiencing rolling blackouts[2].
- ***COVID-19 related Load shift:*** At the start of the pandemic in March 2020, customer load initially dropped for which SJCE had prebought and then had to sell at depressed prices as demand dropped. In addition, commercial load fell and residential load increased as businesses shut down and people worked from home. Residential load tends to be peakier than commercial load since when temperatures spike, commercial buildings have more sophisticated systems to manage their energy usage whereas residential customers do not have the same tools at their disposal. Both selling power at depressed prices and then increased load sensitivity to high temperatures also contributed to higher power costs.

RA costs have also been significantly higher than planned for all three years of study as part of this report. In general, with increasing renewables in the market, and natural gas plants retiring as well as

[1] https://www.cbc.ca/news/canada/british-columbia/pipeline-explosion-prince-george-stress-cracks-1.5485082
[2] https://www.utilitydive.com/news/california-releases-final-root-cause-analysis-of-august-rolling-blackouts/593436/

Diablo Canyon operational issues[3], this has limited RA capacity. In addition, uncertainty from a regulatory perspective has impacted longer term plant investments also curtailing RA. Here are some of the more specific factors contributing to higher RA costs:

- ***Timing of SJCE's RA purchases the first year:*** RA is bought a year in advance, by the end of October, for the following year. In its first year, SJCE had to pay a premium to purchase RA in the Fall of 2018 for service in 2019 after other entities (including other CCAs) had already fulfilled their requirements. In addition, as a result of a new regulatory requirement, SJCE was required to purchase RA in January and February 2019 as their entire load including small commercial customers which did not come online until June 2019. This new requirement added approximately $5 million to RA costs in 2019.
- ***2018 Qualifying Capacity Change affecting renewables:*** This change was the implementation of Effective Load Carrying Capability ("ELCC") modeling for determination of the qualifying capacity ("QC") of wind and solar resources starting 2018. Energy Division staff measure ELCC as the amount of loss of load equivalent ("LOLE") mitigation that a class of generators provides relative to an equivalent amount of ideal or "perfect" electric generating capacity. Adoption of ELCC values resulted in a significant reduction in QC values for solar resources compared to 2017, with August QC values reduced by approximately 50 percent[4]. This therefore increased the amount of RA that CCAs would have to procure relative to the IOUs, given CCAs' larger renewable content.
- ***Lack of availability of local RA:*** LSEs cited several reasons for these deficiencies in their local waiver requests. All of the LSEs issued Requests for Offers ("RFOs") and/or bid into RFOs issued by other entities. While some were able to procure capacity, none of the LSEs seeking local waivers received enough to meet local RA requirements at prices they deemed reasonable. While some LSEs rejected offers they considered too high, many were unable to procure capacity even when they offered prices well above the local trigger price of $40/kW-year. LSEs also reached out directly to generators, brokers, and other LSEs, but were unable to identify sufficient available capacity to meet their requirements[5]. This resulted in penalties to SJCE and thereby increasing their total RA costs.

REC costs were in line with the Plan for 2019 but higher than Plan for 2020. In 2019, costs of RECs were lower and SJCE bought a portion of lower cost unbundled RECs, PCC3. In 2020, SJCE also decided to move to higher quality PCC1 and PCC2 RECs as starting in 2019 PCC3 RECs were no longer being counted as under RPS as Carbon-free renewables on the PCL. As more of SJCE's long term renewable contracts start coming online end of this year and the end of next year, we would expect these costs to decrease.

For 2020, Brown power and RA contributed almost equally to the increase in costs above what was forecast in the Plan, while RECs, although rising, were less of a contributing factor.

---

[3] https://www.kcbx.org/energy/2020-11-10/planned-and-unplanned-shutdown-at-diablo-canyon-halts-all-electricity-generation

[4] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2018-ra-report-rev.pdf

[5] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/ra_market-report_revised-final.pdf

1.4 Power Mix

SJCE's actual power mix for 2018-2020 (percent RPS & carbon-free) are compared to 2017 projections in this section. Over the span of three years (2018-20), SJCE was able to either match or outperform the projections in terms of RPS and Carbon-free percentages for the most part.

The 2017 plan presents four scenarios with varying levels of renewable resources in SJCE portfolio, out of which, two scenarios (Match PG&E, PG&E + 10%) are summarized in Table 4. Over the span of three years, SJCE was able to either match or outperform the projections in terms of RPS and Carbon-free percentages for the most part. SJCE outperformed the PG&E Match RPS plan by 15 and 9 percentage points in 2018 and 2020 respectively. In 2019, SJCE was able to match the projections. With respect to PG&E + 10% scenario, SJCE outperformed the projected RPS by 5 percentage points in 2018. In 2019 and 2020, SJCE underperformed the projected RPS by 10 and 1 percentage points respectively.

Table 5 details PG&E power mix for 2018-20 and SJCE's actual power mix for the same period. There was a dip in SJCE's RPS and Carbon-free content in 2019. After the regulatory rule change in PCIA methodology in 2018, SJCE decided to discontinue buying the Carbon-free attribute as the Carbon-free attribute was already being paid for by SJCE's customers via PCIA. SJCE also decided to move to higher quality PCC1 and PCC2 RECs as PCC3 RECs were no longer being counted as Carbon-free renewables on the PCL . These two factors caused a dip in SJCE's RPS and Carbon-free content in 2019. Starting in 2020, SJCE started receiving carbon-free allocation from PG&E, as part of an agreement in one part of the PCIA negotiations.

Table 4: SJCE's projected power mix

	Match PG&E		PG&E + 10%	
Year	**%RPS**	**%Carbon-free**	**%RPS**	**%Carbon-free**
2018	33	63	43	73
2019	35	66	45	76
2020	37	69	47	79

Table 5: SJCE's actual power mix compared with PG&E power mix

	PG&E		SJCE	
Year	**%RPS**	**%Carbon-free**	**%RPS**	**%Carbon-free**
2018	39[6]	85	48[7]	100
2019	29[8]	100	35[9]	64
2020	31[10]	84	46[11]	89

1.5 Greenhouse Gas reductions

SJCE's GHG reductions for 2018-2020 are compared to 2017 projections in this section.

Minimizing the GHG reductions through the procurement of additional renewable resources was an important factor in the formation of the CCA.

Projected emission reductions for two scenarios (PG&E + 10%, PG&E + 20%) are summarized in Table 6 and Table 7. As it was unclear which specific resources would be replaced by renewables, the 2017 Plan estimated the minimum and maximum emissions. The Plan also did not display total emissions but only estimated emission reductions. SJCE calculated the emissions factor themselves in 2019 by multiplying their total non-carbon free power (all power except renewables, large hydro, and nuclear) by the CAISO system emissions factor provided by California Energy Commission ("CEC") for 2019. The system emissions factor was the same in 2019 and 2020. In 2020, the emissions factor was automatically calculated in the PCL template provided by the CEC by using the emissions factor of each plant SJCE received power from. The new methodology used in the PCL is more comprehensive than SJCE's 2019 calculation therefore the actual reduction shown is partially due to methodology change and partially due to emissions reductions. Table 8 outlines the actual emissions and emission factors for 2019 and 2020. Emission factors are in metric tons (*"MT") Carbon Dioxide equivalent ("CO2e")/MWh* and the total emissions are given in *MT CO2e.*

The actual emission reduction for 2020 was in between the low and high range for the PG&E + 10% scenario for 2019 which is a reasonable proxy because of the delayed start and ramp up of SJCE's service. 2020 emission data was not included in the Plan.

---

6 https://www.pge.com/pge_global/common/pdfs/your-account/your-bill/understand-your-bill/bill-inserts/2019/1019-Power-Content-Label.pdf
7 https://sanjosecleanenergy.org/wp-content/uploads/2021/10/UPDATED-2020-Power-Content-Label_SJCE-PDF.pdf
8 https://www.pge.com/pge_global/common/pdfs/your-account/your-bill/understand-your-bill/bill-inserts/2020/1220-PowerContent-ADA.pdf
9 https://sanjosecleanenergy.org/wp-content/uploads/2020/12/2019-Power-Content-Label-San-Jose-Clean-Energy-SJCE.pdf
10 https://www.pgecorp.com/corp_responsibility/reports/2021/pf04_renewable_energy.html
11 https://sanjosecleanenergy.org/wp-content/uploads/2020/05/SJCE-2018-Power-Content-Label.pdf

Table 6: Projected Additional renewables and Emission reductions (PG&E + 10%)

PG&E + 10%			
	Additional Renewables (GWH)	YoY Emission reduction – Low (MT CO2e)	YoY Emission reduction – High (MT CO2e)
2019	377	152,267	304,535

Table 7: Projected Additional renewables and Emission reductions (PG&E + 20%)

PG&E + 20%			
	Additional Renewables (GWH)	YoY Emission reduction – Low (MT CO2e)	YoY Emission reduction – High (MT CO2e)
2019	754	304,535	527,660

Table 8: Actual Emission factors and Emission reductions

Year	Emission Factor (MT CO2e/MWh)	Total Emissions (MT CO2e)	YOY Emission reduction (MT CO2e)
2018			
2019	0.153	529,074	
2020	0.086	345,114	183,960

1.6 Rates and Savings

In this section, SJCE's rates and savings to customers for 2018-2020 are compared to 2017 projections.

SJCE's rates and savings were projected for scenarios involving various levels of renewable resources as shown in Table 9. Actual rates and savings from 2019-20, for the three SJCE customer plans, are summarized in Table 10. All rates are given in dollars per kilowatt-hour ($/kWh). SJCE's rate is calculated excluding delivery charges (i.e., SJCE rate = Generation + PCIA + Franchise Fee Surcharge ("FFS")). This rate is then compared with PG&E's generation rate to calculate the savings.

The 2017 plan has delivery charges embedded into the rates. Delivery charge for 2019 is calculated by subtracting PG&E generation rate (from appendix B) from PG&E rate in plan. This delivery charge is used to calculate SJCE rates for various scenarios. SJCE's savings are recalculated using the aforementioned approach. This is done to keep the process of calculating projected rates and savings consistent with actual savings.

2017 plan projected the savings on total bill (Generation + PCIA/FFS + PG&E delivery fee) to be 4.2% for 'Match PG&E' scenario and 3.8% for 'PG&E + 10%' scenario. However, SJCE's actual savings are calculated only based on Generation rate + PCIA/FFS. In order to keep the comparisons consistent, Delivery charges were removed from 2017 plan rates and savings were recalculated. SJCE maintained the savings at 1% for its GreenSource offering while the plan projected a savings of 7.425% to 8.25% for the two scenarios (Match PG&E, PG&E + 10%).

Table 9: SJCE's projected rates in $/kWh and savings in percentages

	RPS		RPS + 10%	
Year	**Rate**	**%Savings**	**Rate**	**%Savings**
2019	0.0934	8.25	0.0942	7.45

Table 10: SJCE's actual E1 residential rates in $/kWh and savings

Year	PG&E Rate[12]	GreenSource[13]	Savings	TotalGreen[14]	Savings%
2018		0.1067		0.1167	
2019	0.1158	0.1146	1.00%	0.1246	-7.64
2020	0.1175	0.1163	1.00%	0.1263	-7.51

As of May 2021, SJCE further differentiated the service offerings to its customers. GreenValue (their current low-cost option) service, which was recently added, keeps the rates on par with PG&E. TotalGreen is still being priced at a premium of $0.01/kWh to GreenSource for E1 Residential. GreenSource and TotalGreen offerings are at a premium of 8% and 16% respectively to PG&E.

1.7 Programs and Economic Development Impacts

This section provides an assessment of the SJCE's programs and economic development impacts compared to 2017 projections.

SJCE Program Selection Framework included the following guiding principles: maximizing GHG reduction opportunities; aligning with Climate San José; promote equity, affordability, and support disadvantaged communities; produce customer and community benefits; and maintain or improve the financial status of SJCE. Given this criteria, the programs SJCE selected tended to lean on external funding. SJCE has initiated three major customer program initiatives since its launch: electric vehicle infrastructure charging through the California Electric Vehicle Infrastructure Program ("CALeVIP"); administration of state-funded energy efficiency programs for residential and commercial customers; and the state-funded Solar Access community solar program for low-income customers living in Disadvantaged Communities ("DACs").

- ***CALeVIP:*** In 2019, SJCE participated with several regional load serving entities ("LSEs") in San Mateo and Santa Clara counties to apply to secure funding from the CEC. SJCE contributed $4M and CEC is

[12] https://sanjosecleanenergy.org/resources/ (Rate Archive)
[13] https://sanjosecleanenergy.org/resources/ (Rate Archive)
[14] https://sanjosecleanenergy.org/resources/ (Rate Archive)

contributing $10M in matching funds. The combined funds ($14 million) are being used as incentives for the installation of electric vehicle charging infrastructure in San José through 2022[15].

- ***Energy Efficiency:*** SJCE is launching Elect to Administer ("ETA") Energy Efficiency programs that will be funded up to $1.7 million per year for a total of $5.1 million over three years through the Public Purpose Program charge funds collected and regulated by the CPUC. The programs are expected to annually reduce 2.8 million kWh of energy and help avoid 905 MT of CO2e of emissions, as well as reach 250 residential households and 103 businesses and schools annually. SJCE can reapply for ETA funding every 3 years[16].
- ***Solar Access:*** In June 2018, the CPUC approved D.18-06-027, adopting three new programs to promote the installation of renewable energy generation in disadvantaged communities ("DAC"), as directed by the California Legislature in Assembly Bill 327. One of these programs is the DAC-Green Tariff ("DAC-GT") program, which provides 100% solar energy and a 20% discount on electricity bills for income-qualifying customers who live in DACs. The DAC-GT program is fully funded by the CPUC through California greenhouse gas allowance proceeds and public purpose programs funds[17]. Through the DAC-GT program, which in SJCE-administered territory is branded Solar Access, SJCE is building a 1.7 MW new solar plant, which could provide renewable power to approximately 600 SJCE customers and save them 20% on their bills.

1.8 Risks

This section provides an assessment of risks identified in 2017 compared to actual events.

1.8.1 Power markets

In Section 1.3, various factors that contributed to higher power costs when compared to plan are discussed in detail.

- ***Enbridge Pipeline Explosion***
- ***Increased wildfire risk and incidence***
- ***Rolling blackouts in 2020 due to heat storm***
- ***COVID-19 related Load shift***

RA costs have also been significantly higher than planned for all three years of study as part of this report. The factors contributing to higher RA costs are discussed in detail in Section 1.3. Here is a list of some of those factors:

- ***Timing of SJCE's RA purchases the first year***
- ***2018 Qualifying Capacity Change affecting renewables***
- ***Lack of availability of local RA***

[15] https://sanjose.legistar.com/gateway.aspx?M=F&ID=cc051e7a-f6f1-40aa-996f-6d0254f03c3b.pdf
[16] https://www.sanjoseca.gov/home/showpublisheddocument/70344/637514390420030000
[17] https://www.sanjoseca.gov/home/showpublisheddocument/66809/637405357579970000

REC costs were in line with the Plan for 2019 but higher than Plan for 2020. In 2019, costs of RECs were lower and SJCE bought a portion of lower cost unbundled RECs, PCC3. In 2020, SJCE also decided to move to higher quality PCC1 and PCC2 RECs as starting in 2019 PCC3 RECs were no longer being counted as under RPS as Carbon-free renewables on the PCL. As more of SJCE's long term renewable contracts start coming online end of this year and the end of next year, we would expect these costs to decrease.

For 2020, Brown power and RA contributed almost equally to the increase in costs above what was forecast in the Plan, while RECs, although rising, were less of a contributing factor.

1.8.2 Rates

PG&E generation rates have fluctuated slightly over the last three years, however, on average, have remained relatively stable. The Plan in the base case estimated PG&E generation rates to increase 2.8% per year over the next 10 years, which left minimal buffer for SJCE to demonstrate savings relative to PG&E.

Table 11: PG&E's generation rate changes for Residential E1

Date of Rate Change	PG&E Generation ($/kWh)[18]	Rate Change
5/1/2019	0.11194	-
7/15/2019	0.11757	5.03%
11/15/2019	0.11777	0.17%
1/5/2020	0.11752	-0.21%
10/1/2020	0.11738	-0.12%
1/1/2021	0.11209	-4.51%
3/1/2021	0.11418	1.86%
5/1/2021	0.11418	-

Delivery charges for PG&E customers have increased significantly over the last couple of years. One of the primary factors is cost recovery related to the wildfires. This increases customers' bills overall.

[18] https://sanjosecleanenergy.org/resources/ (Rate Archive)

Table 12: PG&E's delivery rate changes for Residential E1

Year	PG&E Delivery Rate (S/kWh)[19]	YOY Rate Change
2019	0.12983	-
2020	0.15136	16.58%
2021	0.17272	14.11%

1.8.3 Regulatory risks (PCIA)

SJCE faced multiple regulatory risks. The PCIA was covered as a risk in the rate category rather than a regulatory risk in the Plan. In the period that we examined, the unprecedented increase in PCIA appears to be the primary reason for SJCE's deteriorating financial position. This coincided with regulatory action that started pegging the PCIA to more short term inputs.

All California electricity customers, whether they are served by IOUs or CCAs, pay a PCIA fee. The PCIA reflects the difference between the IOU's above-market costs related to legacy power supply commitments, including third-party energy contracts and operating costs for power plants they own, and today's market value for those resources. The CPUC updates each utility's PCIA every year based on updated IOU projected costs and CPUC estimates of IOU portfolio values[20]. In a 2018 decision (D.18-10-019)[21], the CPUC adopted a number of changes to PCIA methodology. Some of the primary changes were:

- Revised inputs to the Market Price Benchmark to improve the initial accuracy of the PCIA that will be in effect each year by introducing an RA adder and a RPS Adder.
- The IOUs were allowed to annually true-up their PCIA rates to reflect actual values realized in market transactions for the subject year for the Brown Power Index.
- Two new balancing accounts were created allowing for the collection of true-ups from the prior year.
- Existing 10-year cost recovery limitation was removed for legacy Utility Owned Generation ("UOG").
- A PCIA cap was instituted as a part of this decision to help mitigate PCIA volatility but was later removed effective Jan 2021.
  A prepayment option was also discussed for Direct Access ("DA") providers and CCAs and was left to Phase two of the proceeding. The PCIA Phase 2 Decision, D.20-08-004 (R.17-06-026)[22] was adopted August 12, 2020. There are a couple of primary factors which make the prepayment option infeasible (i) The decision requires CCAs to pay IOUs a collateral fee and "risk premium" charge in addition to the actual PCIA prepayment and (ii) It also authorizes the IOUs

[19] https://sanjosecleanenergy.org/resources/ (Rate Archive)
[20] SJCE PCIA fact sheet final Feb 2021
[21] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M232/K687/232687030.PDF
[22] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M345/K020/345020131.PDF

to establish a CCA prepayment “viability screen” and “lottery” process limiting how many entities can approach the IOUs for a prepayment option on an annual basis.

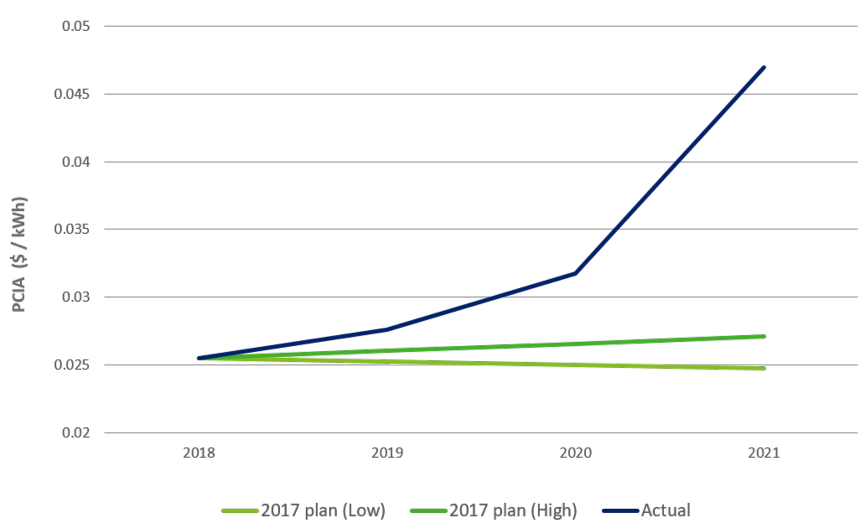
- Table 13 shows the changes in PCIA over the years.

Table 13: Actual vs Projected and Year-on-Year increase in PCIA for Residential E1

Year	Average of PCIA for Residential E1 ($/kWh)[23]	Actual YOY Increase	YOY increase in plan
2018	0.02552		
2019	0.02759	8.1%	-1% to 2%
2020	0.03177	15.2%	-1% to 2%
2021	0.04696	47.8%	-1% to 2%

Figure 1 shows how the PCIA would have increased/decreased for the two scenarios in plan with 2018 as the baseline year. It also shows how PCIA actually changed over the years.

Figure 1: Actual vs Projected PCIA for Residential E1



The changes to the PCIA calculation methodology increased the volatility of the PCIA by pegging it to more short-term inputs. The Energy Resource Recovery Account (“ERRA”) is a balancing account where the utilities record and track energy procurement costs (fuel and purchased power). Inaccuracies in the ERRA forecast produce cash flow impacts to CCAs. Given the cap that was instituted and then removed resulted in the higher PCIA in 2021 with the IOUs receiving under collections from the prior year in

[23] https://sanjosecleanenergy.org/resources/ (Rate Archive)

addition to the current year PCIA. In the period examined, **this unprecedented increase in the PCIA can be identified as the primary reason for SJCE's deteriorating financial position.** Even in the 'high case' sensitivity analysis within the Plan, the PCIA was forecasted to increase by 25% and then decrease by 2% per year in subsequent years.

1.8.4 Liability to the general fund

SJCE's liability to the General Fund of the City of San José is limited by contractual language in all of its procurement agreements that state that obligations are limited to SJCE, the Clean Energy Fund, rather than the general fund of the City of San José. There are notable exceptions to this including the CAISO agreement and the commercial paper program that SJCE has obtained through the City.

1.8.5 Financing required

The Plan assumed an initial loan of $5 million at the start of Phase 1, which was intended to cover municipal facilities, and a second loan of $50 million for the start of Phase 2 which was to address municipal, residential, and small commercial accounts. SJCE obtained a loan from the City of San José to cover initial startup funding and working capital requirements of the venture of $10 million. This initial loan has since been paid back to the City.

SJCE also agreed to a revolving credit agreement with Barclays Bank PLC ("Barclays") of $50 million initially which they later increased to $80 million in May 2019 which provided both a line of credit and letter of credit ("LOC") to SJCE. The LOC is used as collateral for power suppliers. This is important as SJCE does not utilize a lockbox to pay power suppliers.

Some CCAs utilize a "lockbox" financial arrangement where revenues from the sale of electricity are deposited into a separate trust account. Suppliers are then paid directly from that account before remaining proceeds are released to the CCA for operations. This is more common in a JPA governance structure but would not likely be favorable for SJCE given their structure and being backed by the City. In this single jurisdiction model, the City would typically prefer to maintain control over revenues.

The amended agreement with Barclays, also increased the letter of credit sublimit from $35 million to $65 million and the loan sublimit from $20 million to $30 million. As a condition of this revolving credit facility, Barclays requires that SJCE maintain a $20 million restricted operating reserve. In June 2021, for anticipated additional financing for the purchase of power and other operating costs of SJCE, the City through its commercial paper program issued Commercial Paper Notes ("CP Notes") in an amount not to exceed $95 million. SJCE financing needs were lower than expected in the early years and have increased as costs and PCIA have increased. However, even though the financing needs increased, the costs associated with the financing was lower than planned.

SJCE's actual financing expenses comprise of Interest Expense, letter of credit fee and commercial paper fee for each year. Projected debt service from 2017 plan is compared against the actual financing expenses which is summarized in . These projections are same for all three scenarios. Actual costs turned out to be lower than projections by 84% in 2019 and 72% in 2020. A comparison of actual and projected financing expenses is detailed in Table 14.

Table 14: SJCE's projected and actual financing expenses ($)

	Projected	Actual
2018	1,170,882	93,458
2019	5,354,849	878,352
2020	5,354,849	1,525,934

1.9 Financial Position

This section provides an assessment of SJCE's financial position compared to 2017 projections. This includes SJCE revenues, power supply costs and other expenses, and financing used.

SJCE's financials were projected based on the renewable power mix for various scenarios and the forecasted load. The tables below (Table 15 and Table 16) summarize the projected financials for 'Match PG&E', 'PG&E + 10%' scenarios. Forecasted power supply costs varied for each scenario based on the renewable resources procured. Financial projections in 2017 plan were given on an annual basis. To keep the comparisons consistent, actual numbers on a yearly basis were derived using SJCE's quarterly financial statements.

The 2017 plan included 'Contribution to reserves' and 'Financing expenses' as part of total operating expenses. These expenses were treated as separate in SJCE's actual financial statements. To keep the comparisons consistent, these expenses were separated from the operating expenses in the projections. They are analyzed separately as Reserves and Financing expenses in the following sections.

The operating margin (Revenues – Operating Expenses) was projected to be $15M for 2018 and around $31M for 2019 and 2020. Actual figures were around -$4M in 2018, $30M in 2019 and $24M in 2020. SJCE underperformed the projections by 5% in 2019 and 22% in 2020.

Operations & Maintenance expenses in plan are inferred to be a combination of Billing and data management, PG&E Fees, Technical services, and staffing. These expenses along with 'General & Administrative expenses' and 'Uncollectible' are treated as 'Other Expenses' and compared with the actuals accordingly.

Table 15: SJCE's projected financial position (Scenario: Match PG&E)

RPS	Revenues ($)	Power supply Costs ($)	Other Expenses ($)	Total Operating Expenses ($)	Reserves ($)
2018	97,913,834	75,075,737	7,920,338	82,996,075	13,746,877
2019	259,686,133	214,170,172	13,731,336	227,901,508	40,176,653
2020	270,430,221	225,825,329	13,915,167	239,740,496	65,511,529

Table 16: SJCE's projected financial position (Scenario: PG&E RPS + 10%)

RPS + 10%	Revenues ($)	Power supply Costs ($)	Other Expenses ($)	Total Operating Expenses ($)	Reserves ($)
2018	99,120,259	78,520,386	7,937,562	86,457,948	11,491,429
2019	262,833,844	223,478,371	13,777,877	237,256,248	31,714,176
2020	273,708,163	234,666,751	13,959,373	248,626,124	51,441,366

Table 17: SJCE's actual financial position

	Revenues ($)	Power Supply Costs ($)	Other Expenses ($)	Total Operating Expenses ($)	Reserves ($)
2018	1,796,303	3,767,444	2,277,481	6,044,925	4,447,769
2019	290,873,358	248,466,175	12,201,173	260,667,348	38,962,876
2020	325,052,397	283,574,961	17,592,637	301,167,598	31,110,382

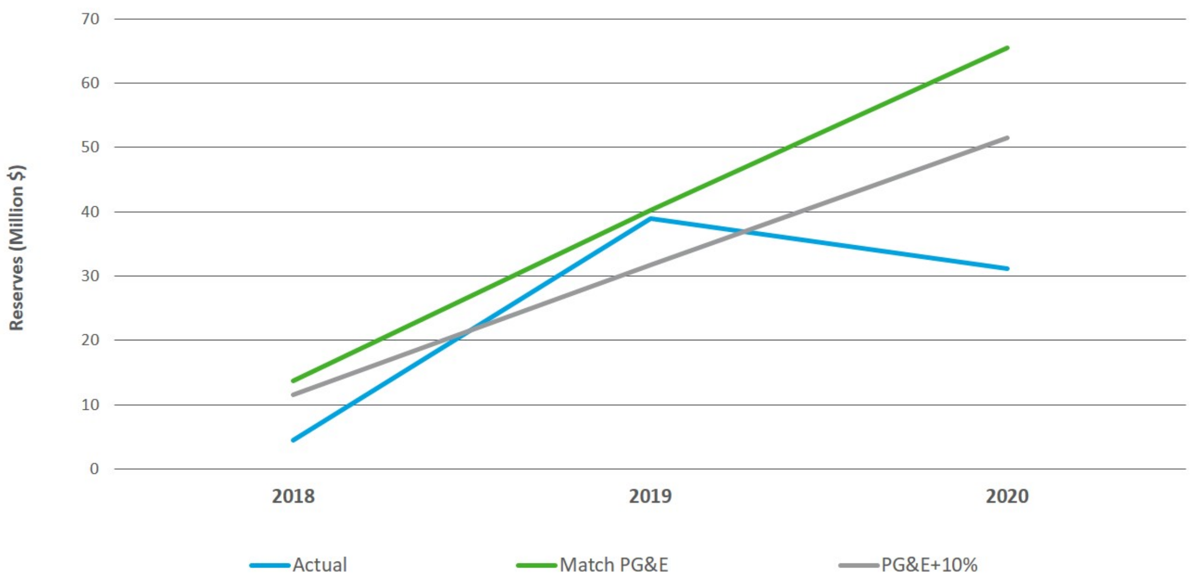
The comparisons below are made for two scenarios in plan (Match PG&E, PG&E + 10%). The plan assumes that SJCE starts offering its services from January 2018. SJCE was actually initiated during the latter part of 2018. This is a major factor in actual 2018 financials being significantly lower than the projections. Taking this into account, comparisons are made only for 2019 and 2020 in the sections below.

SJCE's revenues were higher than projections by approximately 11% to 12% in 2019 for both scenarios. For the year 2020, the actual revenues were higher by 20% for 'Match PG&E' scenario and by 19% for 'PG&E + 10%' scenario. Even though the actual load is a bit lower than projections in 2019 and 2020, generation rates are higher than projections which caused the revenue to be higher. For 'Match PG&E' scenario, the actual power supply costs were 16% higher than projections in 2019 and 26% greater than projections in 2020. Similarly, for 'PG&E + 10%' scenario, actual power supply costs exceeded the projections by 11%, 21% in 2019 and 2020 respectively.

Other expenses comprise of all operating expenses other than power supply costs. These can also be termed as Non-power supply costs. Non-power supply costs include billing and data management, staffing, general and administrative costs, materials and supplies etc. Projected non-power supply costs are within the same range for all four scenarios. In 2019, SJCE's actual costs were approximately 11% lower than projections. In 2020, the actual costs were approximately 26% greater than projected costs for both scenarios. In 2020, SJCE became fully operational. Therefore, as customers and load increased, so did related costs for PG&E billing services, data services and Letter of credit fees. In addition, as mentioned previously, the Plan appears to have underestimated the staff needed in the full staff scenario. So, headcount continued to increase in 2020 as the Department continued to staff up to necessary levels.

Cumulative reserves in the 2017 plan were compared against 'Cash and Cash equivalent – ending' section of SJCE's actual cash flow statements. SJCE's actual reserves are inclusive of commercial paper.

Figure 2: SJCE's projected and actual reserves



As shown in *Figure 2*, for 'Match PG&E' scenario, SJCE's actual reserves were 3% lower than projections in 2019 and 52% lower than projections in 2020. For 'PG&E + 10%' scenario, SJCE's actual reserves were 23% greater than projections in 2019 and 40% lower than projections in 2020.

Task 2: Industry Trends and Market Analysis

This section covers several industry and market trends. Deloitte obtained a significant amount of the information from existing SJCE work products or public data and from related experience with industry and market trends.

2.1 PCIA and Generation Rate

This sub-section provides an assessment of SJCE's projection of the PCIA and PG&E's generation rate for 2022-2025. Review SJCE current models are reviewed to provide an assessment of the accuracy. Sensitivity and risk analysis are performed for PCIA and generation rate trends in 2022-2025 that SJCE should prepare for.

The classical regulatory compact sets out the traditional utility model in which the utility is granted a monopoly on servicing load in a territory in exchange for and obligation to serve that load and the ability to earn a reasonable and regulated return on the portfolio of investments made to serve the load. The PCIA is intended to determine that legacy costs associated with that portfolio of longer-term arrangements to serve the load is fairly allocated between the exiting load and the load that remains with the IOU. The PCIA is often expressed as:

PCIA (above market cost) = total portfolio cost – portfolio market value.

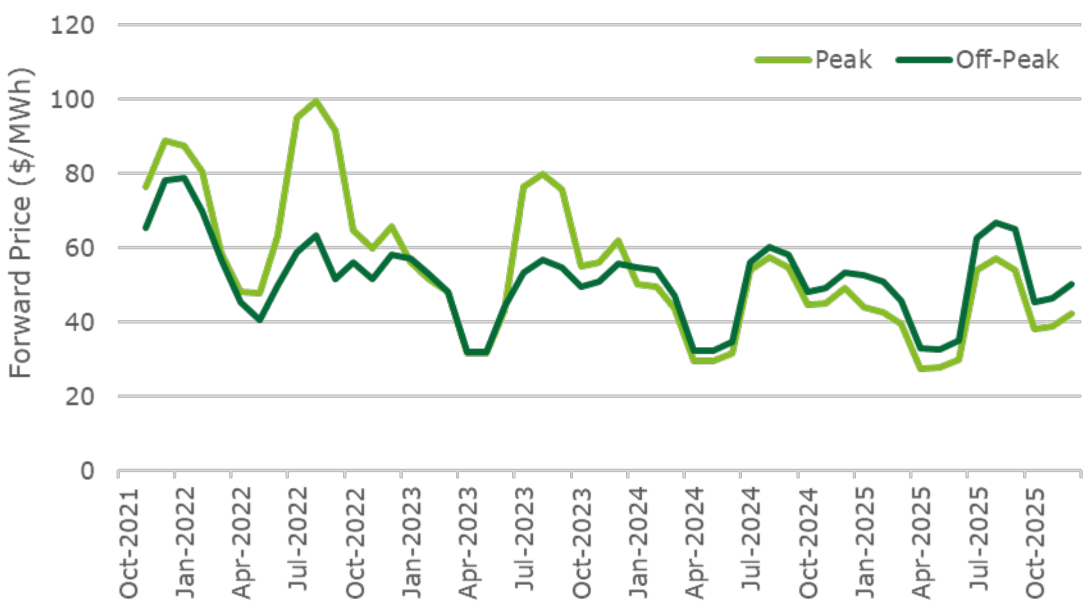
While this equation looks simple, there are many complications. Traditionally, the portfolio to serve the load would consist of physical generation assets owned by the utility. With competitive wholesale power markets and financialization, the supply portfolio could still retain utility-owned assets but would also often include physical or financial contract positions. The exact composition of the portfolio has become commercially sensitive as other market participants may adjust prices or otherwise transact in ways to erode the value of the portfolio to the advantage of the market participant. Preventing disclosure of the portfolio may protect its commercial value, but it also erodes transparency.

Limited information on the portfolio makes projection for that part of the PCIA difficult. Even if an estimate can be made using the market prices and resulting PCIA, that provides only a snapshot of the portfolio value, and does not directly indicate how the portfolio may evolve over time. Despite the challenges and limited visibility, observable market prices can be an indicator, albeit only partial and limited, for where the portfolio market value (and therefore the PCIA) may be trending.

Regulatory changes to the calculation of PCIA adopted after the 2017 Business Plan have changed the PCIA outcomes relative to expectations far beyond a change in market prices. Valuing the IOU supply portfolio entirely against the wholesale market price without consideration for value enhancing attributes (such as renewable) made for lower market value and thus higher PCIA. These regulatory changes are difficult to predict and model, leaving forward market prices as a common area of focus in PCIA analysis.

Among the most accessible market prices is the forward curve which is a representation of the term structure of prices, that is, the series of prices transactable on a given date (the as-of-date) for delivery of a commodity at a range of future delivery dates or periods. The forward curves for peak and off-peak pricing of CAISO NP15, the node closest to SJCE, are illustrated in Figure 3.

Figure 3: CAISO NP15 Forward Curve as of October 13, 2021



Source: CME Group via S&P Capital IQ Pro

The forward curve shows the strong summer seasonality in peak power prices with the price for peak power deliverable in August 2022 at $100/MWh as contrasted with a price as low as $30/MWh for delivery in April 2023. Of note in this instance of the curves is that peak prices trend below off-peak prices by 2024, driven by the lower peak prices (off-peak prices are relatively unchanged or even slightly increasing across the delivery horizon). The lower peak prices are a reflection of expectations around increasing share of solar in the generation mix.

Also, of note is that the forward curve is relatively high in the earlier delivery periods than it has been in the recent past. An important contributor to these higher power prices is the price of natural gas which has increased to levels not seen in years due to lower than expected supply conditions and storage inventories, both in the US and globally.

The PCIA model utilized by SJCE allows for selection and modification of different forward curves and their potential impact on projected PCIA. The SJCE Pro-Forma model can incorporate the PCIA projection (including curve modification) along with its own input forward curves to estimate potential cost of supply positions.

For more liquid commodities, the forward curve typically changes from day to day and often throughout the trading day. Because the forward curve on a given as-of-date reflects the confluence of influences and inputs on that date, some moves may be rather idiosyncratic with temporary jumps or drops. How this is addressed varies by context and market entity. SJCE has adjusted the methodology over time including using a rolling average of a trailing period of trading days. The various industry approaches and implications are discussed in a later section of this document.

An approach to evaluating sensitivities to different forward curves is to apply the current curve along with specified curve shifts are different intervals. The PCIA model provides multiple input variables, primary among are forward energy prices and PG&E bundled generation rates. Along with the base assumptions as of late October 2021, shifts in the forward curve of twenty percent and forty percent above and below the base assumption were applied. These scenarios represent shifts in the market price benchmark ("MPB") for Brown Power and are indicated by names with MPB BP. An additional set of four shifts were done with price shifts in system RA, also where the four cases were at twenty percent and forty percent both above and below the base. These scenarios are indicated by names with MPB RA. All nine cases are summarized below along with chart legend assignments for colors and line styles. Changes in the RPS MPB have less impact on the PCIA, so scenarios varying RPS MPB were omitted for this exercise.

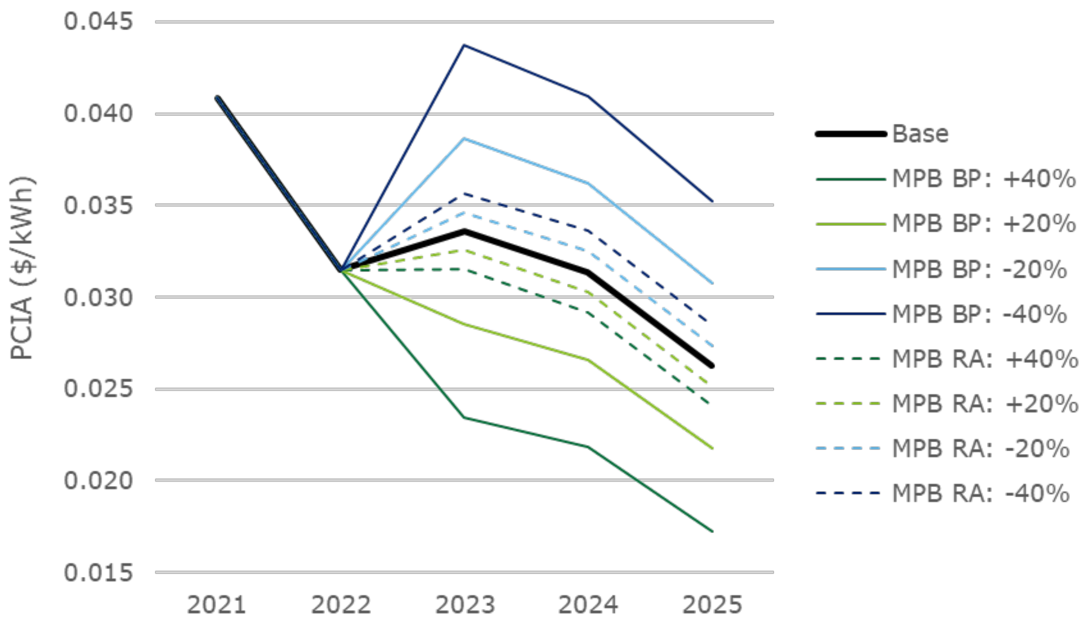
Table 18: Scenario impacts on PCIA

Scenario Name	MPB BP Shift	MPB RA Shift	Color	Line Style
Base	0	0	**black**	solid
MPB BP: +40%	+40%	0	**dark green**	solid
MPB BP: +20%	+20%	0	**light green**	solid
MPB BP: -20%	-20%	0	**light blue**	solid
MPB BP: -40%	-40%	0	**dark blue**	solid
MPB RA: +40%	0	+40%	**dark green**	dashed
MPB RA: +20%	0	+20%	**light green**	dashed
MPB RA: -20%	0	-20%	**light blue**	dashed
MPB RA: 40%	0	-40%	**dark blue**	dashed

Figure 4 compares the range of scenario impacts on PCIA relative to the base assumptions. Increases in the MPB have the opposite directional impact on PCIA (i.e., reduction). The highest resulting PCIA, therefore, is with the scenario with the largest decrease in MPB, and *vice versa*. Shifts in the MPB BP have a greater impact on PCIA levels than shifts in the MPB RA for the same relative change in the respective input curve.

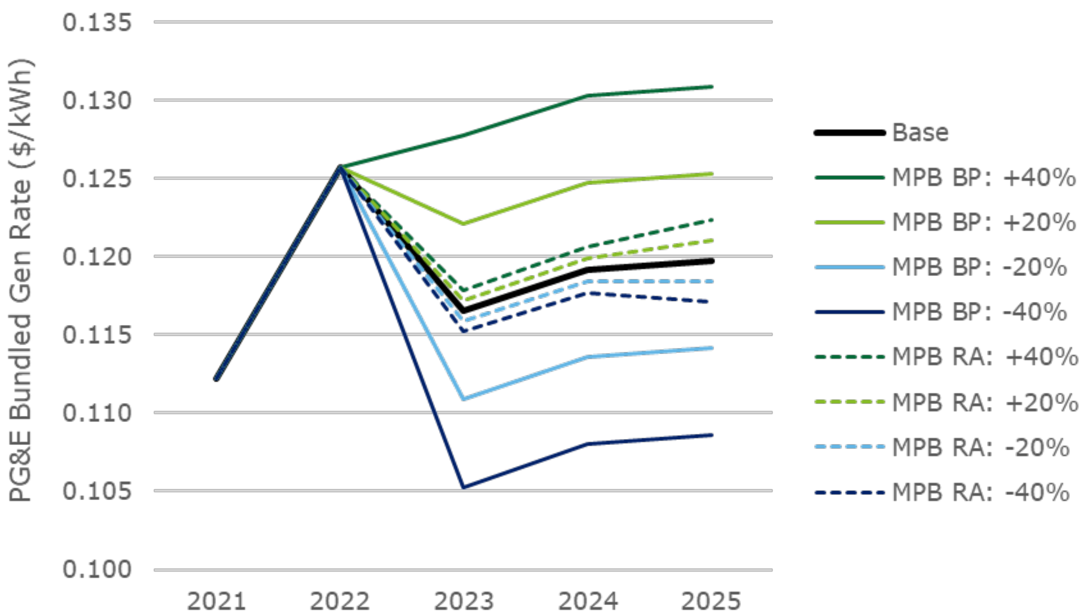
The base projection is for generally declining PCIA in the coming years, though 2023 has an expected increase over 2022 while remining below 2021.

Figure 4: Comparison of PCIA Projection Scenarios



While PCIA and market prices move in opposite directions, estimates of PG&E bundled generation rates move in the same direction as shifts in the MPB BP and MPB RA. As with PCIA, however, moves in MPB RA have less significant impact than similar relative moves in MPB BP. The comparison of PG&E bundled generation rates as projected by the model is show in Figure 5 below.

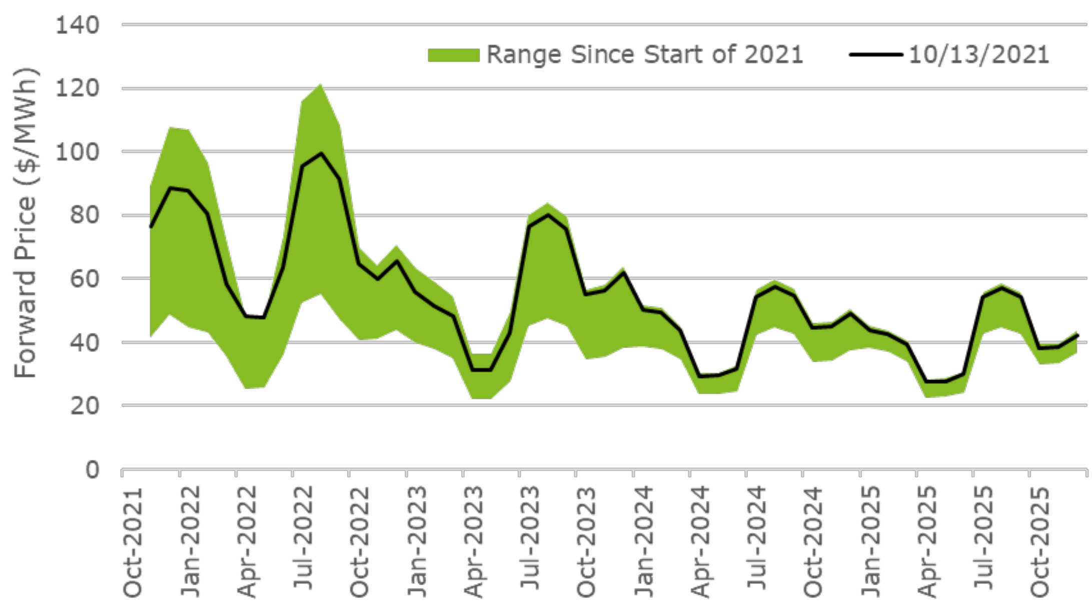
Figure 5: Comparison of PG&E Bundled Generation Rate Projection Scenarios



In considering the shifts in inputs to use in scenarios, looking to history can provide a guide. The actual range over which prices (or other inputs) have moved is one indicator. The risk analyst should keep in mind that the future can unfold differently than the past, and as fundamental factors such as more renewable energy, more storage capacity, and potentially different regulatory treatments can all affect the future in ways unseen in the past. In that context, historical variation still provides value, perhaps if only to set minimum shifts to investigate.

Figure 6 illustrates the range and variation of the forward curve for NP15 peak power from the beginning of 2021. Such a range can inform the selection of the sensitivities to use when stress-testing projections. For the front of the curve through summer 2022, the high of the forward curve range was much higher than the curve as-of October 13, 2021. The lower observations are generally from early in the year before the mid-February 2021 winter storm when extreme cold throughout much of the country caused gas prices to rise sharply, even in California where temperatures were more normal. While the forward prices for late 2021 and Summer 2022 have moved below the earlier highs, they remain well above the lows. For the later forward periods in 2023 and 2024, the recent forward prices remain at or near the year's highs.

Figure 6: Range of Historical Forward Prices for NP15 Peak Power



Source: CME Group via S&P Capital IQ Pro

2.2 COVID Debt Relief

This section provides an assessment of SJCE's projections on the amount COVID debt relief expected from state funding and internal collection efforts and an assessment of how much will be uncollectable and written off.

The COVID-19 pandemic has disrupted employment and the economy broadly resulting in difficulty for many utility customers to pay their bills. Recognizing this revenue shortfall also challenges the financial standing and flexibility of utilities, the American Rescue Plan Act of 2021 ("ARPA") provided funding to states to offer relief. SB-135 Human Services Omnibus (2021-2022) has proposed to utilize ARPA funds to establish the California Arrearage Payment Program ("CAPP") in which the Department of Community Services and Development could provide funding to utilities to apply as bill credits for customers with past due bills. The bill was signed into law by Governor Newsom on [insert date]. Three points of note include:

- The arrearages eligible for coverage are only those during the "COVID-19 pandemic bill relief period" defined as the period beginning March 4, 2020 and ending June 15, 2021;
- Of the $993,500,000 appropriated for the CAPP, $694,953,250 would be allocated for "financial assistance to all distribution customers of investor-owned utilities, including customers served by a community choice aggregator;" and
- Funds must be dispersed to utility applicants no later than January 31, 2022.

In the two months leading into the COVID-19 pandemic bill relief period, SJCE Uncollected Accounts averaged $277,000. The monthly Uncollected Accounts from April 2020 to May 2021 averaged approximately $530,000. Uncollected Accounts during the applicable relief period may total approximately $8.9 million, though June 2021 saw a large increase in Uncollected Accounts ($2.3 million) relative to surrounding months or the prior June. The projected monthly Uncollected Accounts from July 2021 to December 2023 averages just under $470,000. While not all of the arrearages are completely attributable to COVID-19 pandemic impacts (pre-pandemic Uncollected Accounts averaged $277,000/month), an incremental $200,000/month in Uncollected Accounts were observed.

While for the CAPP funds will help utilities with the ballooned customer arrearages, there would still be arrearages outside the relief period after June 15, 2021. On November 2, 2021, the California Community Services Department issued CAPP Program Notice No. 2021-06-E2[24], the latest official notice from the agency administering the CAPP program. This Program Notice showed that SJCE has been allocated approximately $4.3M in CAPP funds. Funds are expected to be fully disbursed before the end of March 2022.

2.3 Power Market Trends

This section consists of an assessment of power market trends and costs, including seasonal and annual volatility and the impacts of an extended drought and the retirement of PG&E's Diablo Canyon nuclear facility and older natural gas power plants on the market.

Supply and Demand Trends

As shown in Figure 7, total generation capacity is expected to increase from 82.3 GW in 2021 to 87.3 GW in 2022 with 3.5 GW generation addition from solar and the other 1.5 GW addition from battery storage and wind. Although solar generation can produce power at near nameplate levels during the daytime, solar generation decreases rapidly into sunset during which times peaking generation like natural gas or storage will need to ramp up to cover this increasing net load (i.e., native load net of solar generation), forming the neck of the so-called duck curve).

[24] https://www.csd.ca.gov/Shared%20Documents/CAPP-PN-2021-06-E2.pdf

Figure 7: EIA Monthly Electric Generator Capacity in California (as of July 2021)[25]

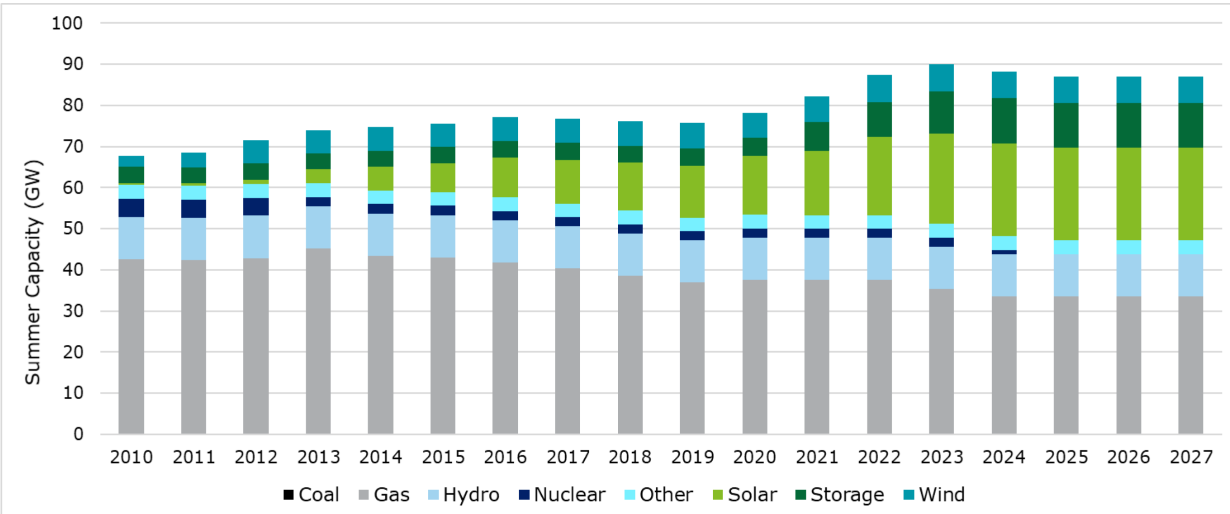


Figure 8: CAISO Average Real Time Market LMP in August 2021

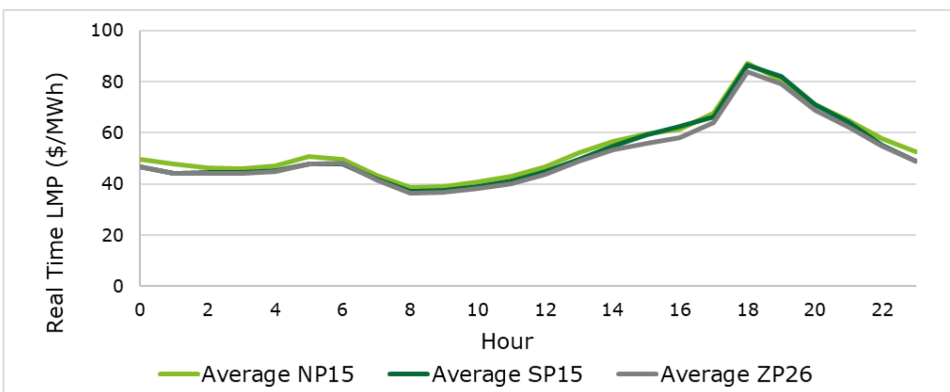
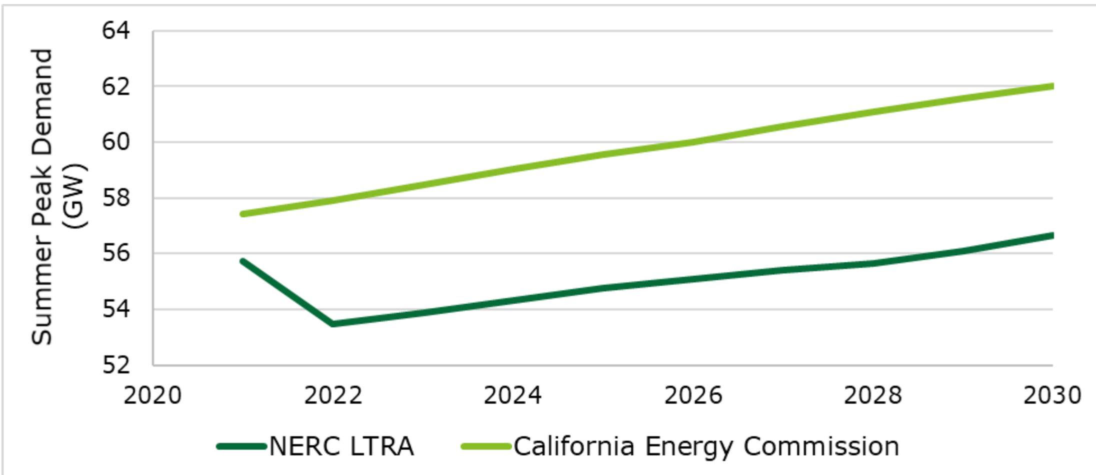


Figure 8 shows the 31-day average August 2021 Locational Marginal Prices ("LMP") variation across the day in CAISO. As mentioned in the previous section, when solar generation decreases in the late afternoon, natural gas generation typically must ramp up to match the increasing net load, and this situation drives the price up (around 18:00 hour in Figure 8). The problem is likely to become more pronounced in 2023 with the expected retirement of 2 GW of natural gas generation capacity, and in 2024 with another expected 2 GW of natural gas retirements. Despite the addition of solar capacity expected, that capacity may not provide enough power in late afternoon and early evening. Although

[25] Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860) - U.S. Energy Information Administration (EIA)

there are plans for an additional 2.5 GW of battery storage by 2024, CAISO power market prices (both Day-Ahead and Real Time) can be expected to be higher and more volatile based on the installed generation capacity stacks.

Figure 9 Summer Peak Demand forecast in California until 2030



The increase of demand will also lower the system operating reserve and potentially result in higher and more volatile prices. Figure 9 shows the summer peak demand forecast in California through 2030. In the NERC Long-Term Reliability Assessment report[26], summer peak demand forecast will drop approximately 2.5 GW from 2021 to 2022, but then showing a 0.7% annual growth rate. The forecast done by California Energy Commission[27] has a steady growth rate 0.9% throughout the horizon, which resulted in about 0.5 GW summer peak demand increase each year. If the demand in California increases steadily like what California Energy Commission has forecasted, it is going to be another driver to push the power market price even higher and with higher volatility.

Diablo Canyon is scheduled to shut down each of its reactors when their licenses expire in 2024 and 2025. The 2.2 GW nuclear plant has operated as baseload generation since 1985 and produced around 16,300 TWh in 2020. Concerns have been raised about grid reliability, and the CPUC has struggled to find resources to replace Diablo Canyon, especially since the State of California has a policy of moving away from fossil fuel generation. The CPUC's ruling in February 2021 recommended procuring 7.5 GW of resources including at least 1 GW of geothermal generation and 1 GW of long-duration (more than eight hours) energy storage to address reliability.[28] Subsequently in June 2021, the CPUC increased the Integrated Resource Planning ("IRP") call for new resources to 11.5 GW.[29]

---

[26] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf
[27] https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report/2019-iepr
[28] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M367/K037/367037415.PDF
[29] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603637.PDF

The California Department of Water Resources had also announced that they will add five new gas generators with 150 MW of total capacity to support grid reliability, of which four have been deployed since September 2021. The new capacity is due in part to the closure of thermal plants and lower water conditions for hydro generation, resulting in the potential for supply shortages as experienced during rolling blackouts in 2020.

California hydro conditions have been again below normal in 2021. This affects both non-dispatchable run-of-river and dispatchable hydro generation, which means that both the total generation capacity and generation flexibility is lower. Since hydro generation has lower variable O&M cost (most of hydro generation variable O&Ms are less than $20 per MWh), this results in higher-than-normal electricity price in California in 2021. In 2014, California also experienced severe drought and high electricity prices (annual average LMP higher than $35 per MWh for both Day-Ahead-Market and Real-Time-Market) when hydro generation only contributed less than 10% of total electricity. Based on NOAA US Seasonal Drought Outlook[30], most of the drought situation in the West is not going to be improved in the winter 2021/2022. Because the drought is so widespread, multiple normal raining seasons are needed to fill up the larger reservoirs to return water levels back to normal. Before this happens, lower than normal hydro production is expected in the West, which again will not benefit power prices.

Low hydro production not only affects electric power market, but also has a negative impact on the natural gas market. Since the hydroelectric power is lower, more natural gas was consumed in the west region to fill the gap of power supply. Generally, natural gas resources are heavily used in the US during winter for space heating. Therefore, the industry builds gas inventory (storage level) during the summertime when prices and overall natural gas demands are lower. In 2021 however, more natural gas was used during summertime due to low hydro generation production and higher gas-fired power generation. Hurricane Ida impacting oil and gas supply in the Gulf of Mexico region combined with higher gas demand resulting in lower than normal US natural gas storage levels. Winter gas prices are also high in the UK and Europe, due in part to low regional gas storage inventories there, adding to domestic US gas pricing pressures with the potential for LNG demand from overseas markets. These supply concerns are already reflected in natural gas monthly forward price in Henry Hub with higher than $5.5 per MMBtu during the winter of 2021/2022 (December to March) as of October 1st, 2021. As CAISO relies largely on natural gas generation in both winter and summer seasons in near future, electricity prices are expected to be higher due to natural gas price increases.

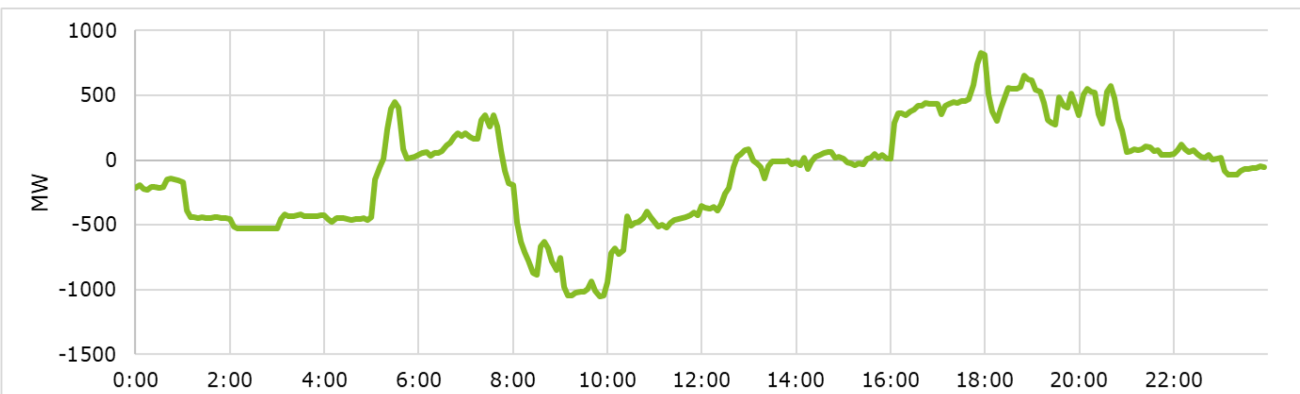
Natural gas demand in the US is highly seasonal, and oftentimes, supply and demand disruptions affect only the upcoming season or two with an assumption of a return to "normal." However, the severe drought across the Western US has brought reservoir levels to record low levels, so improving hydro conditions are expected to continue to weigh on energy production (and therefore gas demand) for some time. Additionally, natural gas production that had already begun declining before the COVID-19 pandemic, dropped further during the initial response and has not fully recovered. Calls for capital

[30] https://www.cpc.ncep.noaa.gov/products/expert_assessment/sdo_summary.php

discipline among investors to avoid overproduction in both oil and gas may finally be taking hold as potentially evidenced by the modest drilling and production recovery. A wait-and-see attitude for added production enthusiasm may also hold supply in check and maintain gas price at levels elevated relative to the past several years.

To address higher renewable penetration and higher renewable curtailment, California will add a total 4 GW of energy storage units between 2021 and 2024. This total is higher than the amount identified in the CPUC IRP targets, which suggests that the overall market perceives greater commercial value in storage than the more reliability-oriented view from the Commission. Energy storage can alleviate the high price volatility problem in CAISO by charging excessive renewable power during daytime and late evening and discharge power into the grid in late afternoon and early morning, as shown in Figure 10. This can help brings down the price spike in late afternoon as shown in Figure 8.

Figure 10 Battery operation in CAISO on August 16, 2021, positive y-axis value is when the battery storage is discharging, and negative y-axis value is during charging



Energy Imbalance Market

CAISO has been relying on import generation from other Western Electricity Coordinating Council ("WECC") regions like Pacific Northwest, Southwest, and Great Basin regions[31]. According to CAISO, during 2017 to 2020 when ISO load is greater than 43,000 MW, the maximum net import is 9.975 GW and the median is 5.069 GW[32], which is only exceeded by solar and natural gas generation. Together with currently expanding Energy Imbalance Market ("EIM") and Extended Day-Ahead Market ("EDAM"), the capacity addition and retirement in WECC will also affect the market price in CAISO.

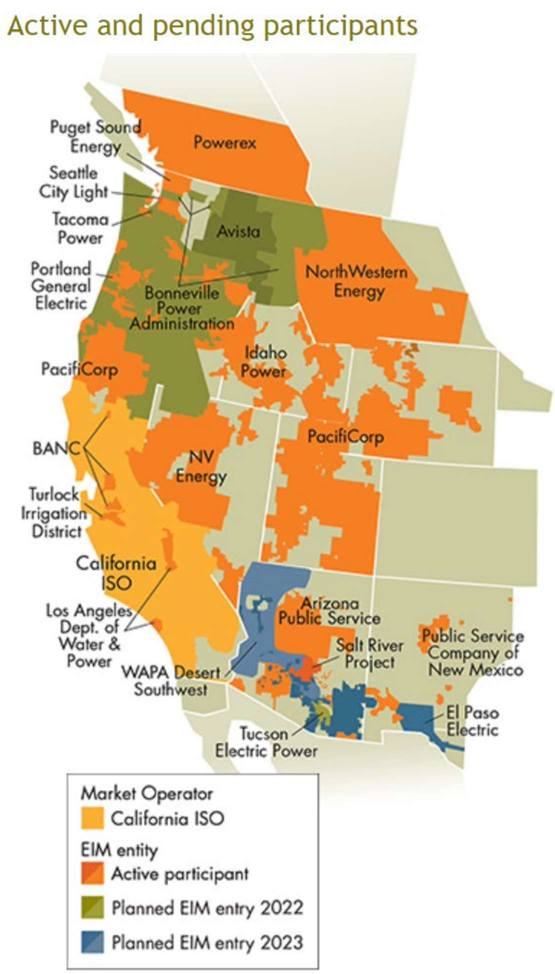
As shown in Figure 11, the CAISO has expanded their markets through EIM. Today, 15 entities including Pacific Corp, NV Energy, Arizona Public Service, and other participants can purchase and sell power on EIM platform. Bonneville Power Administration ("BPA") has completed extensive assessment and public

[31] https://www.eia.gov/outlooks/aeo/pdf/nerc_map.pdf
[32] http://www.caiso.com/Documents/2021-Summer-Loads-and-Resources-Assessment.pdf

process to came to a final decision to join EIM in March 2022[33], where it can provide its hydro power as a flexibility resource in all EIM regions. BPA has more than 20 GW of hydro generation and drought conditions are likely to eventually improve in Northwest region according to NOAA drought outlook.[34] Currently, BPA exports up to 9 GW of power to British Columbia and California (average export in June 2021 is 4,451 MW). After joining EIM, tools to increase the efficiency of BPA's transmission operations and mitigate congestion cost will be provided. EIM will also develop opportunities to compensate generator's flexible capability.

[33] https://www.bpa.gov/Projects/Initiatives/EIM/Pages/Energy-Imbalance-Market.aspx
[34] https://www.cpc.ncep.noaa.gov/products/expert_assessment/sdo_summary.php

Figure 11: EIM territory



Besides EIM, California also has an EDAM initiative to develop an approach to extend the day-ahead market to EMI participants. EDAM is expected to improve market efficiency by scheduling generators across larger areas. The initiative is currently under proposal development and several workshops, webinars, and trainings have been held by CAISO since 2019. CAISO intends to have a stakeholder call in late in October and gather stakeholders' comments in December to come up with a final proposal for EDAM operation detail. With the current EDAM development plan, EDAM working groups will finalize the policy design in 2022 and start EDAM implementation as early as the beginning of 2023.[35]

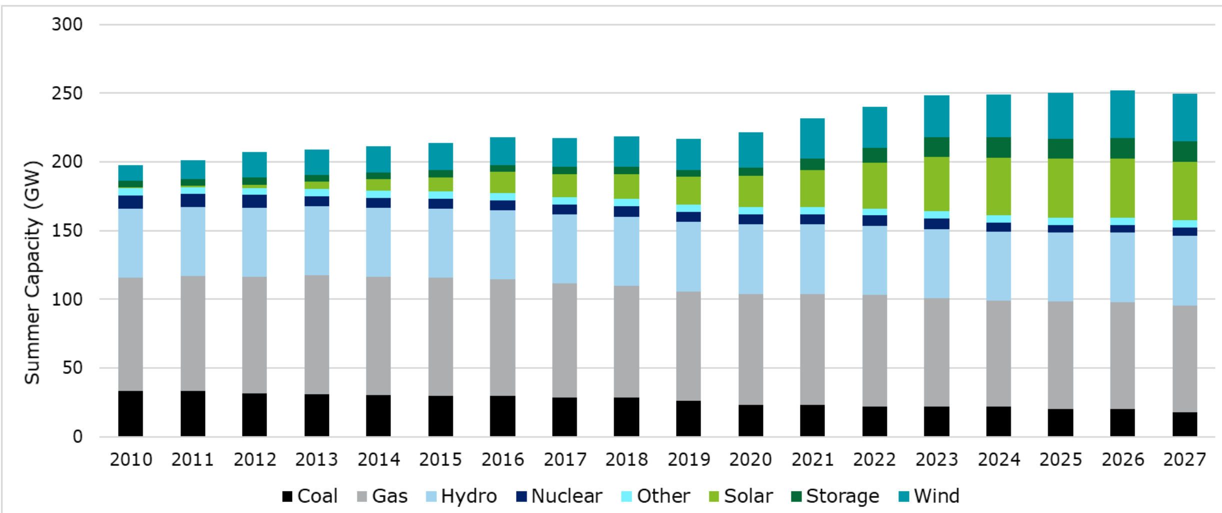
With expanding the real time market and day-ahead market in the west, more generation resource options are available in the market. Regions like BPA had a power surplus and will be able to sell their excessive power. Energy trading between regions will be more responsive where resources can react to EIM real-time price signal, utilizing resource flexibility capability larger area. This will likely result in smoother and flatter supply curve, which leads to lower power price on average, and reducing power spike. With a larger geographic diversity, demand is higher and more spread out, which also reduces the oversupply potential and thus mitigates the likelihood of extreme low prices. Large geographic diversity will also smooth the average variable renewable energy generation changes due to weather changes in one area, which is beneficial with fast growing renewable penetration in WECC.

Figure 12 shows the generation capacity changes until 2027 in WECC region excluding British Columbia and Alberta. As shown in the plot, the region is facing similar issue as CAISO. With more than 3 GW of coal, 2 GW of nuclear, and 4 GW of natural gas retiring, the region plans to have around 15 GW of solar, and 6 GW of energy storage, and 4 GW of wind built in next five years. Since the WECC regions like

---

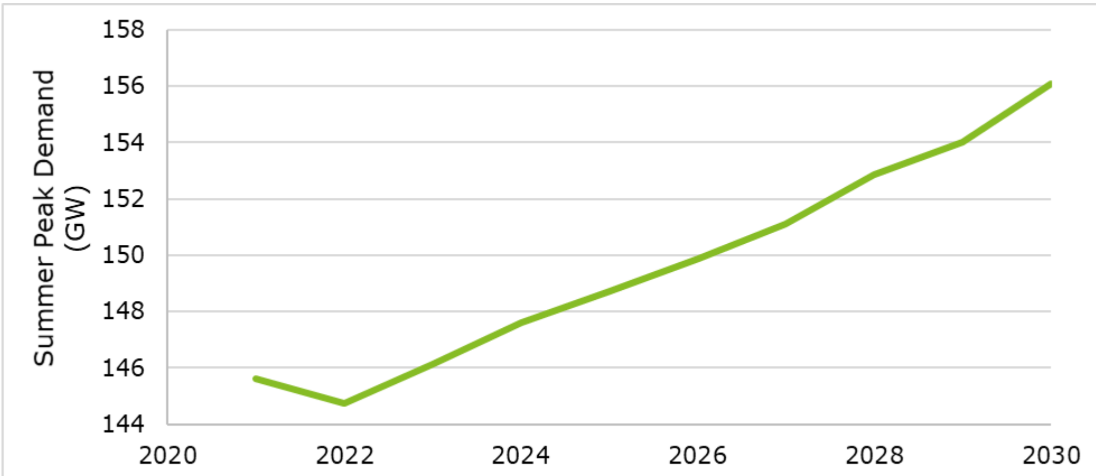
[35] CAISO, Extended day ahead market development plan. https://www.caiso.com/Documents/ExtendedDay-AheadMarketDevelopmentPlan.pdf

Northwest Power Pool ("NWPP"), Southwest Reserve Sharing Group ("SRSG"), and Rocky Mountain Reserve Sharing Group ("RMRG") have higher reserve value compared to California, meeting the summer peak demand is not as difficult. However, under this clean transition from thermal generation to renewables and energy storage, WECC regions will need to rely more on natural gas generation to balance the grid when renewables underperform before energy storage can catch up, especially during the drought season where hydro generation also produce below normal.



Similar to California, WECC summer peak demand is expected to drop by 1 GW in 2022 and grow back steadily with a 0.95% annual growth rate based on NERC LTRA forecast. This peak demand drops in 2022 will help WECC regions in near term but the low reserve/ high price problem will likely to return in 2024 when the high summer peak demand returns.

Figure 13: Summer Peak Demand forecast in WECC excluding British Columbia and Alberta from NERC LTRA



Overall, the following are the positive (lower price and price volatility) and negative drivers summarized for CAISO price and price volatility:

- Positive Drivers: Expanding power market region through EIM and EDAM, lower peak demand in 2022, and more energy storage coming online.
- Negative Drivers: Thermal generation shifting to solar and wind, growing demand after 2022, high natural gas price, and drought condition in WECC.

2.4 Financial projections model

This section aims to provide financial projections in an excel model for SJCE based on the assessment of 1, 2, & 3. The model should include expected monthly and annual revenues, costs, financing, and reserves. The model should include and expected range based on the uncertainty of inputs and assumptions.

The forward curve plays an important role in projecting the cost of supply, the PCIA, and other major inputs to the financial modeling of SJCE. As previously described, the forward curve may (and does) change over time, sometimes quite significantly. On any given as-of-date, the curve might be particularly high or low relative to surrounding days, and there are some implications of this, and different ways firms use address the issues.

When something varies over time, taking a snapshot such as a forward curve on a specific as-of-date can potentially capture an idiosyncratic moment or temporary aberration. One approach is to realize this, but ultimately accept that “it is what it is” and use the snapshot knowing it is a specific observation that may have individual peculiarities for that day. In this way, the curve of the as-of-date is used as-is. This is often the case in accounting contexts where the valuations of positions are tied to a specific date, such as transaction close, reporting period end, or a date to align with other reporting or uses.

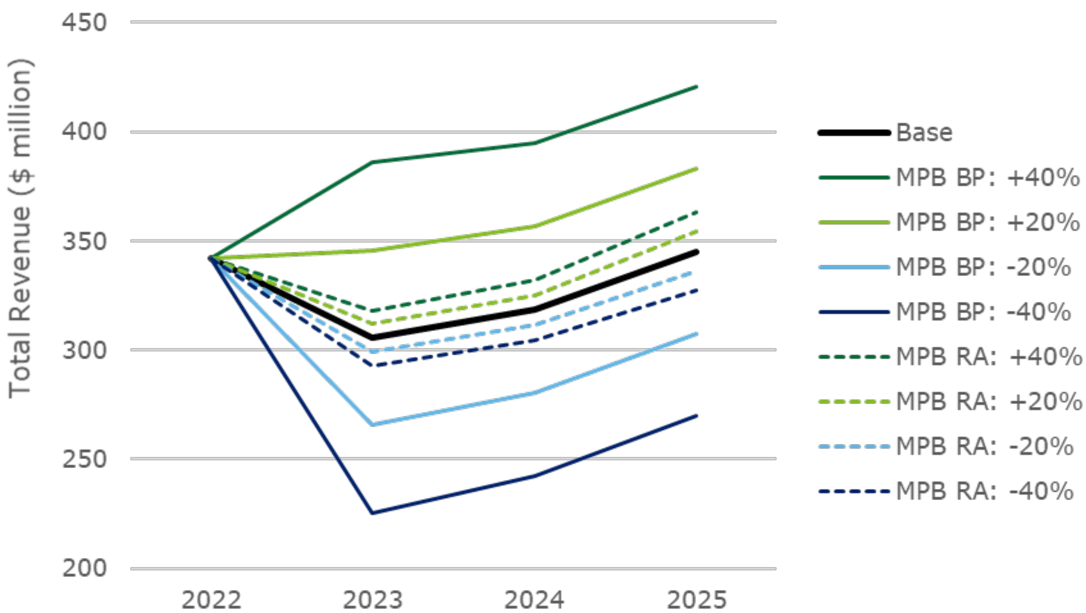
Another approach is to average observations. This will tend to reduce the influence of a specific date or a specific transaction that may move or set the market. In markets that set pricing based on transaction prices such as for certain index products, to reduce or avoid the potential for manipulation or idiosyncratic events, an averaging of trade prices may be used. This is usually a small set such as the last three days or trading.

SJCE has deployed a method using a moving average for a trialing period of time. In an earlier approach, the trialing period was six months. At one point, because the market was in a relatively long-term trend, the six-month window was slow to reflect the recent changes, which meant the signaling to management was also delayed. To address this, SJCE moved to a shorter 60-day window.

While the desire to reduce the impact of any one day's move on the curve is understandable, the method to address this is use- or context-dependent. For financial reporting, budget comparison, and similar situations, the key-day as-of-date is typical. The key-day is aligned with the date used for other inputs into the computations. For analytical purposes, the date may be less tied to dates in other reports, but the curve from a single as-of-date is still often the most used. To capture the variability and potential that the observed as-of-date is somewhat anomalous, other metrics or input can be used.

As noted earlier, one approach to addressing potential variability in the forward curve is to apply scenarios. Drawing on the same scenarios and associated PCIA and PG&E bundled generation rates described in Section 2.1, shifts in inputs to evaluate sensitivities and potential outcomes can be run through financial models. SJCE rates are priced at parity to PG&E for this and subsequent analysis in this section. Costs for SJCE can be affected by both energy price moves and RA price changes, though primarily on the uncontracted exposures. Forward procurement of expected loads affects the remaining uncontracted exposure, which affects the impact from these forward price shifts. Figure 14 illustrates the SJCE Total Revenue projections under the scenarios.

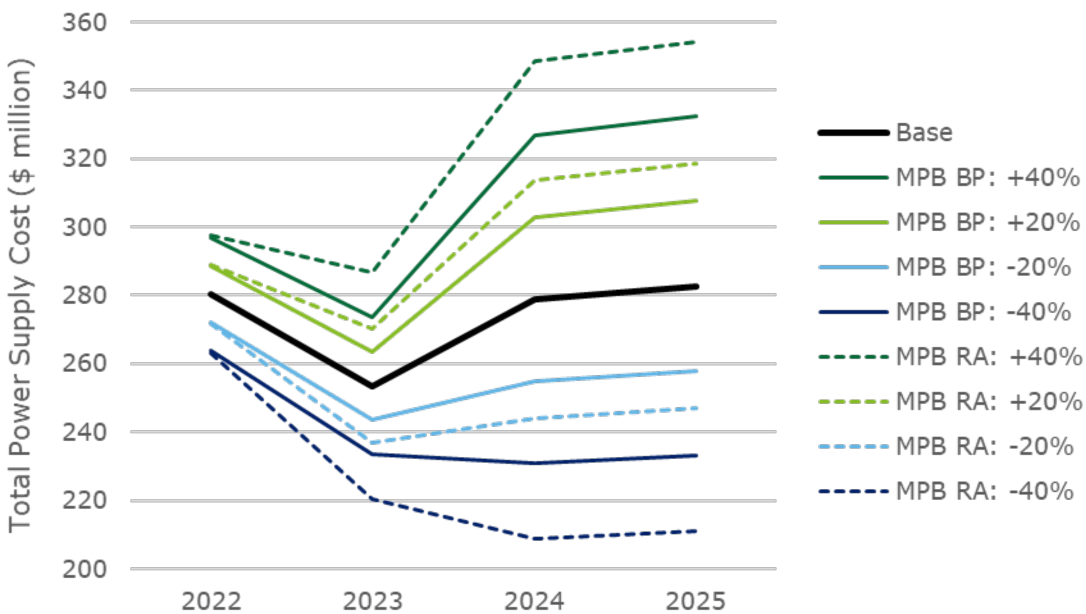
Figure 14: Comparison of SJCE Total Revenue Projection Scenarios if rates are set at parity to PG&E



While the range from +40% to -40% of MPB BP covers a relatively wide span of potential market pricing, the impact on Total Revenue is also quite large exceeding $80 million for a 40% MPB BP move in 2023. The market shifts affect not only the top line but also other aspects of the total revenue/cost situation with SJCE Power Supply Cost and Net Revenue discussed below. One approach to managing the uncertainty is through a reserve account, and the magnitude of these potential swings can suggest appropriate levels of reserve when the broader risk management objectives are included. Changes to the rate structure, such as via a shift to cost of service, and energy contracting practices can also adjust the exposure of SJCE to market moves and uncertainty.

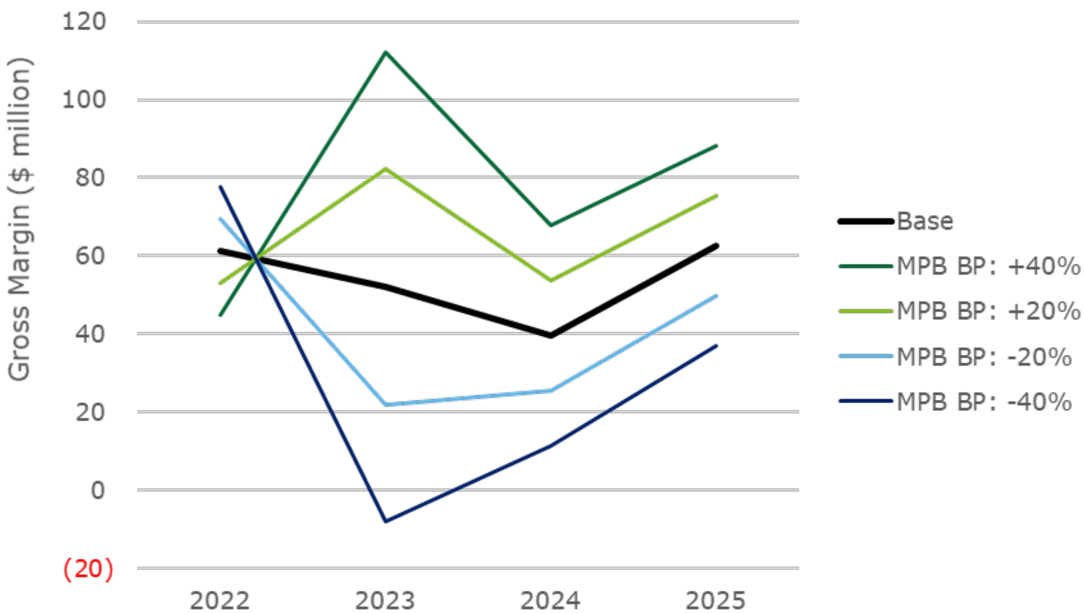
Defining total power supply costs as costs for power including CAISO costs, contracted and open BP energy costs, contracted and open RPS/GHG-Free energy costs, contract and open total RA costs, but excluding pre-payments, with recent contracted estimates, SJCE total power supply costs are more sensitive to shifts in MPB RA than relatively similar shifts in MPB BP. That is, for a given percentage change in MPB RA, the resulting change in total power supply cost greater in magnitude than the change would be under the same percentage shift in MPB BP. This is illustrated across the set of scenarios as in Figure 15.

Figure 15: Comparison of SJCE Total Power Supply Cost Projection Scenarios



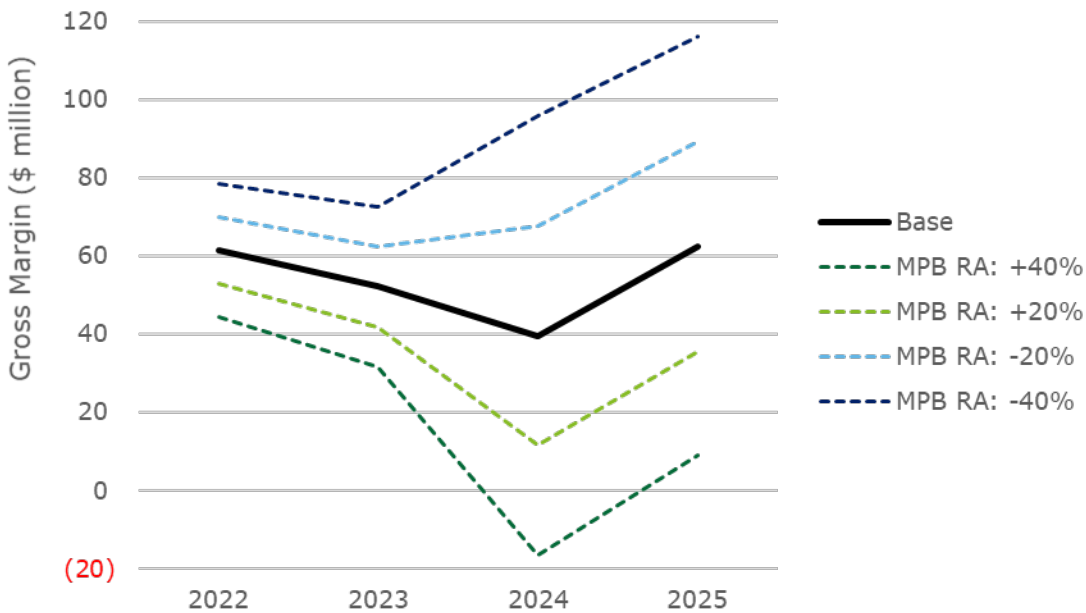
The differences in total revenue and total power supply costs to changes in MPB BP or MPB RA lead to different sensitivities from the gross margin, computed as the arithmetic difference of the total revenue and the total power supply cost. Figure 16 illustrates the changes in gross margin under shifts in the MPB BP. Larger shifts upward in MPB BP have greater positive contribution to gross margin. The MPB BP increases both the effective rate and the underlying cost, however, the impacts on the rate (via PCIA shift) and revenue are larger in magnitude than the impact on costs, leading to a positive net change to the gross margin.

Figure 16: Comparison of SJCE Gross Margin Projection for MPB BP Scenarios



Shifts in MPB RA affect gross margin in the opposite direction. An increase in MPB RA causes a reduction in gross margin. The changes in gross margin under the different scenarios are shown in Figure 17 below.

Figure 17: Comparison of SJCE Gross Margin Projection for MPB RA Scenarios



With the scenario of increasing MPB BP by 40%, gross margin in 2023 dipped slightly negative, whereas a decrease in MPB RA by 40% resulting in a negative gross margin in 2024.

2.5 Comparable CCA Rates and Products

This section aims to summarize the rates and products of similar CCAs and compare to SJCE's and also identify rates and products that may be advantageous for SJCE to consider.

Comparable CCAs were picked among the members of CalCCA. CCA's proximity to SJCE and its size were considered in choosing appropriate comparable CCAs which are listed in Table 19. Most of the comparable CCAs were operationalized prior to 2018 giving them enough time to build reserves during the period when PCIA was relatively low.

Table 19: Comparable CCAs and their rate setting mechanism

CCA Name	Operational Start	Rate Setting Mechanism
Clean Power San Francisco (CPSF)[36]	May 2016	Cost of Service
Silicon Valley Clean Energy (SVCE)	April 2017	Pegged to PG&E
East Bay Community Energy (EBCE)	June 2018	Pegged to PG&E
Redwood Coast Energy Authority (RCEA)	May 2017	Pegged to PG&E
Peninsula Clean Energy (PCE)	October 2016	Pegged to PG&E
Valley Clean Energy (VCE)	June 2018	Pegged to PG&E
Sonoma Clean Power (SCP)	May 2014	Pegged to PG&E
Marin Clean Energy (MCE)	May 2010	Pegged to PG&E
Central Coast Community Energy (3CE)[37]	March 2018	Cost of Service

Most of the above comparable CCA rates are pegged to PG&E rates. EBCE, RCEA, PCE, and VCE set their low-cost service rates slightly lower than those of PG&E. CPSF's goal is to set rates once for the entire year through a public process, providing customers more rate and cost stability. 3CE's Cost of Service rate structure enables improved predictability through long-term rate adoption. 3CE's new rate structure also takes into account what it costs to serve each customer segment and helps to ensure customer rates fairly reflect the cost to provide services to each customer class.

In Table 20, PG&E's E1 Residential generation rates as of May 2020 are compared with low-cost service offerings of various CCAs. The 2020 power mix associated with the rates for various CCAs is summarized in Table 21. The primary reason behind picking this period is to compare the power mix in conjunction to the rates and keep the comparisons consistent. Most of the CCAs only published their 2020 power mix most recently and May 2020 is the only period of rate change that is consistently available across most CCAs for the year 2020. Corresponding May 2020 rates are not available for a couple of CCAs (PCE, MCE) for comparison. Rates are obtained from archived PG&E rate comparison files and historical rate files present in CCA websites.

EBCE offered the highest savings (4.51%) for its customers in the aforementioned period. CPSF, which is the only comparable CCA that follows a single jurisdiction model, took an approach similar to SJCE's, offering 1% savings with respect to PG&E rates. SCP offered the least savings (-5.98%) among all comparable CCAs. Please note that 3CE's rates and savings are omitted from these comparisons as the rates present in their archives for May 2020 are unreasonably low.

---

[36] CPSF's goal is to set rates once for the entire year through a public process, providing customers more rate and cost stability. Rates will always be set through the same public process that is used to set water and sewer rates here in San Francisco. This process includes San Francisco Rate Fairness Board review, San Francisco Public Utilities Commission review, and approval by the San Francisco Board of Supervisors.

[37] 3CE's Cost of Service rate schedule will begin on January 1, 2022 https://3cenergy.org/rate-choices/

SVCE and EBCE which offered higher savings (4% and 4.51% respectively) than SJCE had lower percentage of eligible renewables in their portfolio (42.5% and 39.6% respectively) than SJCE (45.1%). One other point of differentiation for SJCE with respect to both SVCE and EBCE is nuclear power. 13% of the GreenSource power mix is from nuclear for SJCE while SVCE and EBCE are only at 9% and 1% respectively. With Diablo Canyon slated to retire over the next 3-4 years, SJCE will lose this part of GreenSource (GHG-free attributes from Diablo Canyon are part of the allocation discussed in Section 1). SJCE would likely need to replace this with other renewables or carbon free sources (like large hydroelectric).

Table 20: Low-cost option E1 residential rates for comparable CCAs ($/kWh)

E1 Rates (Low-cost option)	Generation	PCIA + FFS*	Total Rate	Savings vs PG&E
PG&E	0.11752	-	0.11752	-
SJCE[38]	0.08235	0.03399	0.11634	1.00%
CPSF[39]	0.08235	0.03399	0.11634	1.00%
SVCE[40]	0.07885	0.03397	0.11282	4.00%
EBCE[41]	0.08177	0.03045	0.11222	4.51%
RCEA[42]	0.08231	0.03403	0.11634	1.00%
PCE			NA	
VCE[43]	0.08355	0.03397	0.11752	0.00%
SCP	0.09012[44]	0.03443[45]	0.12455	-5.98%
MCE			NA	
3CE[46]	0.0406[47]	0.03399	0.07459	

*Different CCAs have different PCIAs and FFSs because the PCIA is based on when CCA customers start CCA service.

---

38 https://sanjosecleanenergy.org/wp-content/uploads/2020/05/052720-SJCE-Rates.pdf

39 https://static1.squarespace.com/static/5a79fded4c326db242490272/t/5f3c64bc51317b79e5f44066/1597793468077/E1_341%2C675+pieces.pdf

40 https://www.svcleanenergy.org/wp-content/uploads/2020.05_Residential-Rates_digital.pdf

41 https://res.cloudinary.com/diactiwk7/image/upload/fl_sanitize,q_auto/ebce-web-comparison-may2020-new-ebce-bill-format-2.pdf

42 https://redwoodenergy.org/wp-content/uploads/2020/05/May-2020-Res-Rates-for-Website.pdf

43 https://valleycleanenergy.org/wp-content/uploads/VCE-JRM-2020.pdf

44 https://sonomacleanpower.org/uploads/documents/SCP-Historic-Rates.pdf

45 https://sonomacleanpower.org/uploads/documents/PGE-Historic-Added-Fees.pdf

46 https://3cenergy.org/wp-content/uploads/2020/05/MBCP-Residential-Rate-Sheet-v13.2.pdf

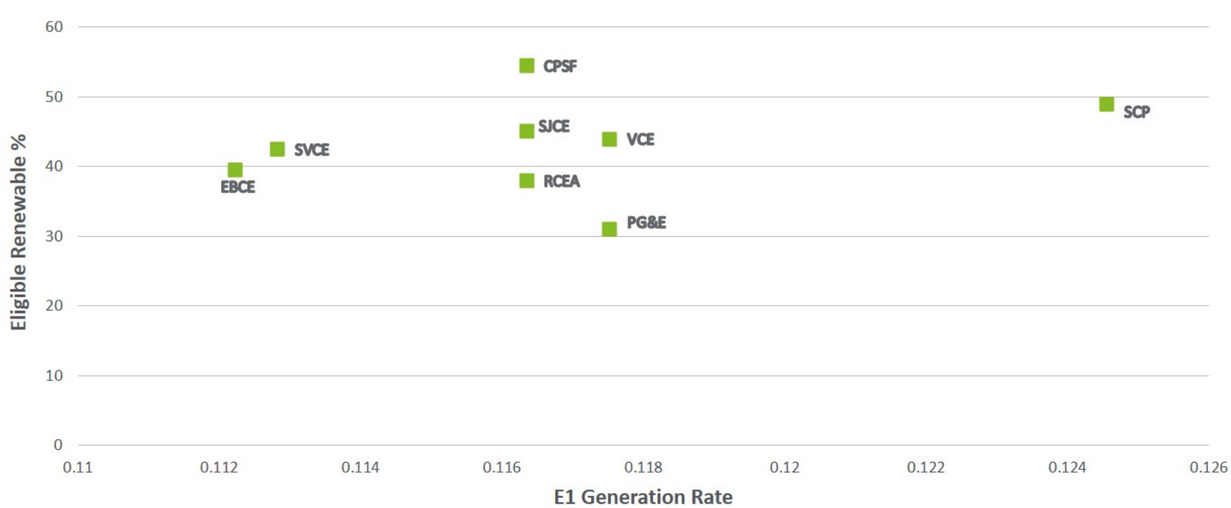
47 May 2020 rates are picked from https://3cenergy.org/archived-rates/

Table 21: Low-cost products offered by comparable CCAs (2020)[48]

Energy Resources %	PG&E [49]	SJCE	CPSF	SVCE	EBCE	RCEA	PCE	VCE	SCP	MCE	3CE
Eligible Renewable	**31.0**	**45.1**	**54.5**	**42.5**	**39.6**	**38.0**	**51.7**	**44.0**	**49.0**	**61.0**	**31.1**
Coal	-	-	-	-	-	-	-	-	-	-	-
Large Hydroelectric	10.0	31.3	42.0	47.5	14.5	34.5	46.7	36.0	44.0	36.0	55.7
Natural Gas	16.0	0.1	-	-	0.1	-	-	-	-	-	-
Nuclear	43.0	12.7	-	9.5	0.9	0.2	1.1	-	-	1.0	-
Other	-	0.4	-	0.3	0.2	0.7	0.1	-	-	-	-
Unspecified	-	10.5	3.5	0.2	44.7	26.3	0.4	20.0	7.0	1.0	13.2

Figure 18 shows both the E1 generation rates and eligible renewable percentage for comparable CCAs. As it can be seen in the plot, CPSF offered the lowest rate with an eligible renewable percentage of 50% or above. SCP's rates are the highest among the comparable CCAs with eligible renewable percentage below 50%.

Figure 18: E1 Generation rates and Eligible renewable % for Comparable CCAs



[48] 2020 power content labels were analyzed for all CCAs in order to keep the comparisons consistent
[49] PG&E's 2020 power mix is taken from https://ebce.org/our-power-mix/

2.6 New Renewable and Storage technologies

This section provides an assessment of new renewable and storage technologies both in front and behind the meter that SJCE should prepare for.

Lithium-Ion Batteries

SJCE can expect short and medium duration lithium-ion storage prices to fall over the next few years, despite current supply-side constraints, and growth in this market is expected to surge over the next five years. According to the Q3 2021 Wood Mackenzie U.S. Energy Storage report[50], total deployments of front-of-the-meter ("FTM") storage are up 300 percent year-over-year, and up 50 percent over the previous quarter with 218 megawatts ("MW") added. Corroborating these projections, an August 2021 report from the U.S. Energy Information Administration estimated that between 2021 and 2023, 10,000 MW of large-scale battery storage will be deployed, more than five times the amount deployed through 2020[51].California led the project deployment, due in large part to a 100 MW energy storage project. Even with this growth, Q1 and Q2 are only expected to make up 12 percent of total expected MW total for 2021 as more projects at a larger scale are expected to come on later in the year. Interconnection queue requests remain high, and this is expected to continue out to 2024. Looking further into the future, battery storage capacity is projected to increase to 13.7 gigawatts ("GW") by 2024 from 5.2 GW in 2021.[52] In terms of market size, energy storage is expected to climb to $8.9 billion by 2026, from an estimated $5.5 billion in 2021.

As of Q3 2021, Wood Mackenzie reports a median price of $1,725 per kilowatt ("kW") for medium-duration (4-hour application) FTM lithium-ion batteries and a median price of $1,525/kW for short-duration (2-hour application) FTM lithium-ion batteries. This represents a price decline of 9 percent year-over-year for both long and short duration batteries. So long as the pandemic does not pose further long-term threats to global supply change, these costs are estimated to lower further through the end of the year. Market share for lithium-iron-phosphate ("LFP") lithium-ion batteries continues to increase in the US due to its cost advantage over nickel-manganese-cobalt oxide ("NMC") batteries. Still, supply chain constraints, high metal prices, and parts shortages are currently negatively impacting the market. These issues have forced vendors to place orders for parts far in advance. In addition, the interconnection queue is at nearly 200 gigawatts. The industry's ability to build out and cut costs will also be affected by the renewable incentives in the federal budget reconciliation bill, which is expected to be passed in December 2021, potentially including Investment Tax Credit for storage.

Looking into the future of lithium-ion, the report discusses four application areas for FTM energy storage. These include ancillary services, capacity and demand management especially in California, transmission and distribution deferral, and renewable integration, especially as more large scale solar-plus-storage projects are announced. These variable use cases will push out FTM energy storage growth

[50] Except where noted otherwise, information from this section comes from Wood Mackenzie's Q3 2021 U.S. energy storage monitor report.
[51] Battery Storage in the United States: An Update on Market Trends | U.S. Energy Information Administration
[52] Electric Power Monthly with Data for March 2021 | U.S. Energy Information Administration
April 2021 Short-Term Energy Outlook | U.S. Energy Information Administration

over the next few years, to an expected deployment of 7 GW in 2026, and California will lead that growth, making up 30 percent of the total market. In the near-term, most systems will not exceed four-hour storage in new deployment.

Pumped Storage Hydropower

Another type of energy storage is pumped storage hydropower ("PSH") and is by far the most common method of long duration energy storage in the U.S., currently accounting for 93 percent of grid storage[53]. Between 2010 and 2019, 1,333 MW of PSH was created in the U.S., almost as much as all other forms of storage combined. In addition, there are currently 67 projects at various stages of development, representing 52.5 GW of storage, seven of which are in California. As a mature technology, costs for pumped hydro storage are expected to remain constant[54], which could benefit SJCE in terms of cost and financial planning. For longer term duration projects, PSH offers lower capital costs than battery storage with an estimated cost of $262/kWh for a 10-hour, 100 MW system compared to $356/kWh for lithium-ion battery storage with the same specifications[55]. However, for shorter term duration storage PSH is less cost effective than battery storage with capital costs for 4-hour duration projects exceeding those of batteries[56]. As the price of battery storage falls, PSH will become a less attractive storage solution with projected costs for 2030 approximating those of lithium-ion battery storage[57]. In additional, siting a pumped hydro project is nontrivial and requires overcoming a number of environmental and other hurdles.

Compressed-air energy storage

Compressed-air energy storage ("CAES") is another potential storage technology SJCE can explore. Currently, the U.S. has a potential domestic capacity of 121 GW[58], although this technology requires specific underground formations such as salt domes, salt beds, and aquifers, which limit its deployment. While CAES technology is not new, only four plants have been built in the U.S.[59]. However, interest has been growing as seen by the 1,500 MW/25,000 MWh plant being developed by Burbank Power and Water in Utah[60]. Costs for CAES plants are projected to remain relatively stable. According to the Department of Energy, in December 2020, a turnkey CAES plant costs between $850 and $1,250/kW[61]. California Community Power ("CCPower"), a Joint Powers Agency comprised of ten CCAs including SJCE, has explored CAES fielding used storage tanks which can be sited anywhere versus large salt caverns. For 8 hour duration storage, CAES fielding storage tanks was not competitive relative to lithium ion batteries. These could become competitive at even longer duration storage.

---

[53] U.S. Hydropower Market Report | U.S Department of Energy
[54] Energy Storage Technology and Cost Characterization Report | U.S. Department of Energy
[55] 2020 Grid Energy Storage Technology Cost and Performance Assessment | U.S. Department of Energy
[56] Ibid.
[57] Ibid.
[58] Energy Storage Grand Challenge: Energy Storage Market Report | U.S. Department of Energy
[59] Ibid.
[60] Energy Storage Technology and Cost Characterization Report | U.S. Department of Energy
World's largest compressed air grid "batteries" will store up to 10GWh | New Atlas
[61] 2020 Grid Energy Storage Technology Cost and Performance Assessment | U.S. Department of Energy

Long-Duration Batteries

In terms of longer-duration storage technology breakthroughs, Form Energy announced details of their new long-duration iron-air battery, which is capable of discharging power continuously for six days. The battery relies on iron, which from a cost standpoint, gives it an edge above its competitors who rely on less abundant materials. The company has said that its battery should be ready for mass production by 2025[62]. This longer-duration technology is promising but SJCE will likely not see its commercial viability in the near-term.

Green Hydrogen

As decarbonization proceeds, many industry stakeholders are considering hydrogen production and storage projects to find ways to cut carbon emissions. As renewable penetration on the grid increases, green hydrogen development is expected to follow because of its potential to act as seasonal storage of fuel available on demand to generate power for grid balancing.[63] Several green hydrogen projects are currently underway in California.[64] The city of Los Angeles' HyDeal LA, which plans to turn Los Angeles into the country's first regional hub for green hydrogen, aims to provide hydrogen fuel at a cost of $1.50/kg by 2030[65]. The city plans to utilize out-of-state salt dome formations in either Utah or Nevada with the capacity to store enough hydrogen to balance supply and demand throughout the year. The hydrogen will then be transported to several gas-fired power plants that the Los Angeles Department of Water and Power California plans to convert to hydrogen fuel. The first of these plants will begin operating in 2025 with 30 percent hydrogen and 70 percent gas and will steadily increase the usage of hydrogen with the goal of fully converting to hydrogen power by 2045[66]. San Diego Gas & Electric has green hydrogen plans in the nearer term, stating that they will have two green hydrogen projects in service by 2022[67]. The Borrego Springs green hydrogen project, which will be located next to their existing Borrego Springs microgrid, will pilot hydrogen as long-duration energy storage to support CAISO grid reliability. Their hydrogen containers will support more than eight hours of energy storage. Additionally, at its Palomar Energy Center in Escondido, the utility will install an electrolyzer to be powered by solar to produce hydrogen on site. This hydrogen will be used to cool generators and as a fuel for fuel cell fleet vehicles. It will also be blended with natural gas as fuel for electric generators and a hydrogen fueling station. With these San Diego projects coming online in the next couple of years, SJCE may want to consider investing in green hydrogen technology in the short to medium term. As noted in the BloombergNEF article, while blue hydrogen is currently the cheaper alternative, which is fossil fuel created hydrogen with carbon capture, green hydrogen is predicted to become cheaper than blue hydrogen as soon as 2030 in all major markets[68].

Another more novel renewable energy tech, offshore wind, will also diversify California's renewable energy sources in the future, as Governor Gavin Newsom signed a bill into law in September 2021

---

[62] Big Money Flows into Long-Duration Energy Storage
[63] 2021 renewable energy industry outlook | Deloitte
[64] SDG&E's Commitment to Sustainability | San Diego Gas & Electric
[65] Los Angeles green hydrogen hub developers map role for gas pipelines, storage | S&P Global
[66] Los Angeles wants to build a hydrogen-fueled power plant. It's never been done before | Los Angeles Times
[67] https://www.sdge.com/more-information/environment/sustainability-approach#hydrogen
[68] https://about.bnef.com/blog/green-hydrogen-to-outcompete-blue-everywhere-by-2030/

mandating a plan be created for offshore wind development in federal waters.[69] The law requires a preliminary assessment of offshore wind in California by the end of 2022, with target years of development in 2030 and 2045. The generation profile of off-shore wind is largely complementary to that of solar plants in California, which would make off-shore wind particularly interesting for SJCE, subject to overcoming permitting and other obstacles.

As previously mentioned, federal policy could have a significant impact on energy storage. While the Biden administration's budget is still undergoing the legislative process and is subject to change, current versions of the bill provide tax incentives for renewable energy production and storage. The current bill includes $320 billion of expanded tax credits for clean energy production, transmission, and storage.[70] The bill would set the investment tax credits for solar projects at 30 percent, an increase from the current level of 26 percent.[71] In addition, the bill would create a new ITC for standalone energy storage projects.[72] While previous drafts of the bill extended production tax credits and investment tax credits until 2034, the current version extends both credits only until January 1, 2027.[73] Beginning in 2027, the ITC would be replaced by a "technology-neutral" credit that lasts until 2031 or when greenhouse gas emission levels for the power sector have fallen to 25 percent of 2021 levels, whichever is later[74]. This technology-neutral credit would be phased out over three years, with facilities being allowed to claim 100 percent in the first year, 75 percent in the second year, and 50 percent in the third year[75]. In addition, the bill includes provisions that allow nonprofits and other groups that do not currently qualify for tax credits[76], to elect to receive a direct payment in lieu of tax credits, which could benefit SJCE.[77] While the election generally applies to credits for the taxable year in which the election was made, for production tax credits ("PTC"), the direct pay election can be made on a facility-by-facility basis for the taxable year of the original placed in service date.[78] If the bill is passed in its current form, it would allow project owners to receive a direct payment for their investments in eligible renewable energy projects instead of a tax credit. SJCE could consider eligible renewable energy asset ownership to benefit from the newly available direct payments.

SJCE should combine their own research with continued engagement with stakeholder groups such as CalCCA, like-minded CCAs and key customers groups to help define their investments in new renewable and storage technologies.

[69] https://www.sacbee.com/news/politics-government/capitol-alert/article254412199.html
[70] Build Back Better Framework | White House
[71] ITC extension, domestic manufacturing support included in US Democrats' Build Back Better framework | PV Tech
[72] What's in the latest 'Build Back Better' budget deal for renewable energy | Renewable Energy World
[73] House Rules Committee Modifies Green Energy Bill | JD Supra
[74] Proposed US clean energy tax breaks could be transformational, but risks loom | S&P Global
[75] Ibid.
[76] Draft federal tax package includes ITC extension and direct pay for solar incentives | Solar Power World
[77] Ibid.
[78] Ibid.

2.7 Customer Demand for Renewable Products

This section provides an assessment of customer demand for renewable energy, new renewable product offerings and programs.

Consumer sentiment and stakeholder pressure to address climate change has been increasing over the past decade and remains strong despite the headwinds caused by the pandemic[79], so SJCE could expect to see increasing demand for residential renewable energy options. In a 2020 national Deloitte survey study of over 1,500 residential participants, 68 percent of respondents were very concerned about climate change and their personal carbon footprint. On top of that, 53 percent said it is extremely or very important that part of their electricity supply comes from renewable energy, a record high since the study's inception. These results are supported by the Pew Research Center's study on clean energy sentiment from June 2021, in which 84 percent of U.S. adults supported expanding utility scale solar energy and 77 percent supported expanding utility scale wind energy[80].

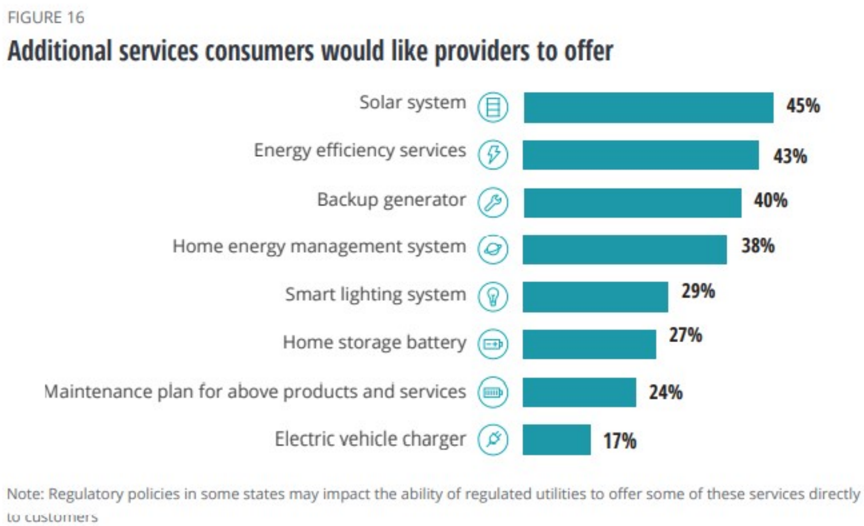
In terms of what consumers want from their electricity providers, the 2020 national Deloitte study found that affordability has remained an impediment to Americans purchasing green energy, even as consumer desire to utilize clean energy sources has risen, so cost still plays a fundamental role in consumer energy choices. This is highlighted by the fact that out of the 20 percent of respondents that recalled being offered green energy options from their providers, only 11 percent purchased green energy, with the top barrier being expense. While a third of consumers reported willingness to pay for green energy, 60 percent would not pay more than a 10 percent premium. As such, SJCE could consider more price-flexible options for residents who are prohibited by cost and continue to market and grow its current low-income programs. Apart from wanting affordable green energy options, consumers also reported that solar systems, energy efficiency services, backup generators, and home energy management systems were technologies they would like their providers to offer., which is aligned with SJCE's current offerings like price variable renewable energy enrollment options, EV rebates and financial incentives, rooftop solar, smart home solutions, and energy efficiency rebates. The percentage breakdown of which additional services consumers would like their providers to offer can be seen in Figure 19.

---

[79] *Deloitte Resources 2020 Study* is the source for this section except where otherwise noted
DI_Resources-study-2020.pdf (deloitte.com)

[80] https://www.pewresearch.org/fact-tank/2021/06/08/most-americans-support-expanding-solar-and-wind-energy-but-republican-support-has-dropped/

Figure 19: Additional Services Consumers Would Like Their Providers to Offer by Percentage



While interest in rooftop solar has been trending downwards from 44 percent in the 2017 report to 32 percent in 2020, 44 percent of consumers reported interest in community solar. Also, more than 50 percent of respondents reported interest in solar panels if combined with battery storage. Among the reasons for this included, greater use of solar, saving on electricity bills, reducing carbon footprint, and preparation for potential outages from natural disasters or storms. This desire for storage is stronger in areas more commonly affected by natural disasters, such as California, as evidenced by the Electric Power Research Institute's mid-April 2020 study that reported consumers from the West were the only ones to retain the same level of interest in solar panels, backup generators, or energy storage from the year prior despite economic headwinds caused by COVID-19. This trend is reverberating in Texas in the wake of the 2021 February freeze. In the September 2021 Forbes article, Sunnova Energy international, a Houston-based residential solar provider, noted that its installed customer base jumped 30 percent from 2020 and new orders increased 165 percent, mainly from new Texan customers but comprising increased demand nationwide[81]. Given these trends, SJCE could consider offering more energy storage and back-up generator options to its residents.

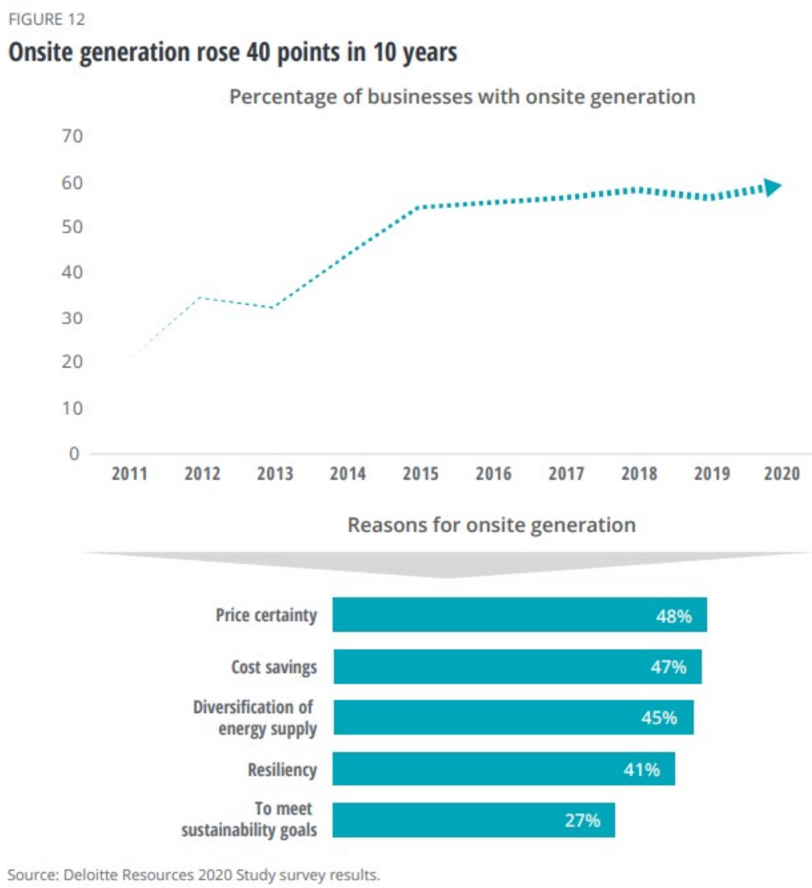
As an impediment to green energy demand, 76 percent of respondents cited concerns about privacy and security as preventing them from purchasing smart home technologies in the next one to two years. The top three barriers to adopting home automation for consumers were concerns about privacy and security, cost, and satisfaction with current home technology. SJCE could offer information on the

[81] Renewables' Revenge: Texas' February Freeze-Out Is Driving A Wave Of Residential Solar

safety, security, and benefits of smart-home products to quell consumer's fears over security and privacy concerns, which could increase the number of residents interested in smart home technologies. SJCE should also communicate the benefits of smart home technologies.

On the corporate side, over 600 businesses were surveyed across five industries in the Deloitte study [82]. Sixty percent of businesses reported having some level of onsite generation due to price certainty, cost savings, diversification of energy supply, and energy resiliency. Figure 20 highlights the increase in commercial adoption of onsite energy and the breakdown of reported reasons for onsite production.

Figure 20: Commercial Onsite Generation Over the Past Decade



[82] Industries captured in the business segment of the analysis included consumer products, industrials, financial services, health care, and tech, media, and telecommunications. All businesses surveyed had 250 or more employees, but company size ranged from small with less than $100 million in revenue to large with over $500 million.

Reiterating businesses' interest in resiliency benefits of renewable energy options, 44 percent of businesses have considered implementing a microgrid, which is up 9 points from 2019. Reasons for this interest included 54 percent having critical operations that require uninterrupted power supply, 51 percent experiencing an increase in electricity outages, and 35 percent wanting to serve as a safe hub for the community in the event of a widespread outage. SJCE could thus consider offering microgrid solutions for a group of businesses that it serves who would see the value in this service and be willing to pay for it. Apart from wanting more energy resiliency, 75 percent of businesses reported that customers were asking them to procure renewable energy, and 51 percent said they are working to procure more electricity from renewables, up from 47 percent in the prior year. This trend is likely to continue to bolster corporate demand for renewable procurement. PPAs are a major way that corporates are procuring, with 11.9 GW of new PPA deals announced in 2020, when a decade ago total corporate PPA procurement only stood at 0.1 GW[83].

Residential consumer demand reflects a desire for more affordable renewable energy options, solar plus storage, back-up generators, community solar, and energy efficiency programs. SJCE currently offers programs that align with consumer demand trends including various affordable RE options, solar rooftop installation, and energy efficiency programs. SJCE could potentially capture more demand by diversifying its offerings, specifically by offering solar with storage, more back-up power options, and community solar. On the corporate side, demand is strong for energy resiliency through microgrids, as well as PPAs to meet renewable energy procurement goals. SJCE could respond to these trends by offering microgrids solutions to its businesses, and potentially PPAs if SJCE is able to benefit from new direct-payment ITCs and chooses to pursue renewable energy asset-ownership.

2.8 Additional Regulatory Compliance Requirements

This section provides an assessment of additional regulatory and compliance requirements that SJCE should prepare for in 2022-2025.

Overview

There are a number of entities that have regulatory impact to SJCE's business. The Federal Energy Regulatory Commission ("FERC") and CAISO are responsible for regulating wholesale energy markets which feed the cost side of SJCE's business. The CPUC regulates the electric utility business in California which both PG&E and SJCE are subject to. One of the key drivers behind the growth of CCAs is to accelerate renewable energy investments and reduce greenhouse gases. The CPUC implements and administers RPS compliance rules for California's retail sellers of electricity, which include large and small IOUs, electric service providers ("ESPs") and CCAs. In addition, SJCE is subject to GHG planning targets set by the CPUC in coordination with the California Air Resources Board ("CARB") in response to the Clean Energy and Pollution Reduction Act (Senate Bill 350) which directs the CPUC to establish the IRP process.

[83] Corporate Clean Energy Buying Grew 18% in 2020, Despite Mountain of Adversity, BNEF

We will discuss the various issues by potential impact.

PCIA

On May 20, 2021, CPUC rendered a decision on the Rulemaking to Review, Revise and Consider Alternatives to the PCIA in proceeding R.17-06-26. The issues before the CPUC included identifying structures, processes, and rules governing portfolio optimization that should be consider to address excess resources in utility portfolios while remaining aligned with existing IRP and RA program modifications; identifying standards to adopt for more active management of the utilities' portfolios in response to potential departing load in order to minimize further accumulation of uneconomic costs; consideration of the time and process to transition to new standards allowing for active management of utility portfolios; whether the Commission should consider new or modified shareholder responsibility for future portfolio management; and, if the PCIA cap should be removed or modified. CalCCA supported comments to remove the PCIA cap, arguing that the cap has caused an increase in rate volatility and uncertainty after the first year and recommended removal. The CPUC has ordered the IOUs to remove the cap and trigger mechanisms effective 1/1/2022, and to amortize undercollected IOU revenue due to the cap over three years. The Order also considered the adoption of a comprehensive, voluntary, and market-based solution to the excess resources issue experienced by IOUs and passed through to CCAs. The Commission adopted a key element of the proposal that requires the IOUs to open up access to renewable energy benefits to all customers who pay for those benefits. However, the CPUC denied provisions of the proposal that would allow equitable access to resource adequacy benefits and deferred consideration of a GHG-free benchmark to a future proceeding

CalCCA has sponsored SB 612 (Portantino)[84]. In July 2021, SB 612 was designated a two-year bill by the Assembly Committee on Utilities and Energy pausing its advancement. However, there are opportunities for it to resurface in the next legislative cycle. If this bill passes, then CCAs would be able to fully benefit from the attributes that they are paying for in the form of PCIA which would then reduce some of the procurement of RA, RPS, and GHG-free products.

RA

Another market change CAISO is considering and has submitted as a proposal before the FERC is a proposal addressing shortcomings and possible improvements to RA with a focus on Maximum Import Capability ("MIC") calculation, allocation, and usage. In light of a potential increase in generation retirement and policy/legislative priorities aimed at increasing environment and renewable targets, CAISO acknowledged that the current MIC annual allocation process may not account for the changing Load Serving Entity landscape. The current MIC Annual Allocation process does not provide LSEs with certainty on consistent annual allocation. Through a year-long stakeholder engagement progress, the ISO reviewed short-term and long-term solutions that would allow a more balanced approach to MIC allocations and facilitate LSE's long-term procurement of import resources through a multi-year allocation process. If approved by FERC, SJCE along with other existing and new CAISO LSEs will be

[84] https://cal-cca.org/sb-612/

permitted to (1) participate in long-term and multi-year contracts for resources dedicated to LSEs that serve loads inside the CAISO Balancing Authority Area and, (2) select and receive the benefits of importing external resources as part of its Resource Adequacy portfolio. (Ref. California ISO, Maximum Import Capability Enhancements Final Proposal[85], 10/11/2021)

On July 15, 2021, the CPUC rendered a decision the Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations in proceeding number R. 19-11-009. The issues before the Commission included examination of the broader RA capacity structure to address energy attributes and hourly capacity requirements, given the increasing penetration of use limited resources, greater reliance on preferred resources, rolling off of a significant amount of long-term tolling contracts held by utilities, and material increases in energy and capacity prices experienced in California over the past years.
The Commission adopted PG&E's slice-of-day proposal as the proposal that best addresses the identified principles and the concerns with the current RA framework and if further developed, is best positioned to be implemented in 2023 for the 2024 compliance year. Workshops are taking place to work out an implementation plan for the proposal, including variations to the RA framework proposed by Southern California Edison ("SCE"). In particular interest to SJCE would be the 'Resource Counting' component and how renewable resources and storage is considered in the new framework.

Central Procurement

In June 2020, CPUC adopted a framework that designated PG&E and Southern California Edison ("SCE") as the central procurement entities to ensure local RA. The central procurement framework has gone into effect this year, 2021, with the investor-owned utilities purchasing the entire amount of required local resource adequacy for 2023 on behalf of all LSEs[86]. This not only limits CCAs' procurement authority and opens them up to more IOU pass through costs, it also disincentives CCAs investments in behind the meter ("BTM") technologies. Continued erosion of procurement authority could significantly impact CCAs' autonomy.

DA Expansion

In its latest Staff report on DA as well as the June 24, 2021 Decision (D. 21-06-033), the CPUC has not recommended further opening up DA at this time. A joint petition for a rehearing of the Decision was issued by several ESPs in July 2021, which California Community Choice Association ("CalCCA") did not support. The CPUC has taken no action on this so far.

DER

FERC issued Order No. 2222 on September 17, 2020 revising guidelines for Participation of DER Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators ("RTOs/ISOs"). In response, RTOs/ISOs were called upon to propose market rule changes to

---

[85] http://www.caiso.com/InitiativeDocuments/FinalProposal-MaximumImportCapabilityEnhancements.pdf#search=LSE
[86] https://www.utilitydive.com/news/california-regulators-establish-sce-pge-as-central-procurement-buyers-to/579786/

comply with the updated FERC guidelines some of which have the potential to impact SJCE. While CAISO already had a DER program in place since 2016, updates to its provision are needed. CAISO conducted a comprehensive gap analysis of FERC Order 2222 requirements against its current distributed energy resource provider ("DERP") provisions. CAISO filed its tariff amendment to comply with Order 2222 on July 19th, 2021. CAISO deployed changes identified in compliance filing such as (1) reducing minimum DERA size requirement of 500 kW to 100 kW; (2) identifying any settlement impact on the broader definition of mixed aggregations; and (3) adjusting aggregation and metering requirements to accommodate baseline measured demand response ("DR") in a DERA. In a March 2021, FERC released Order No. 2222-A, upholding the small utility opt-in mechanism for those with four million megawatt-hours or less in annual sales as it preserves the local decision-making authority to allow aggregations. Additionally, FERC will evaluate the issue on the opt in/opt out rules applicable to DR resources in its Notice of Inquiry considering the DR opt-out established in FERC Order Nos. 719 and 719-A. SJCE will need to continue monitoring FERC decisions for these rule changes as it evaluates its portfolio of power suppliers. A challenge to overcome for market participant and state regulators will be how to manage interconnection rules that allow DERs to operate in wholesale markets without destabilizing distribution grids as well as how market participants management of third-party risk will need to shift. With a number of RTOs/ISOs requesting extensions for proposed market changes, it may take several years for SJCE to see full impact from DER integration into the CAISO market.

SJCE joined five other CCAs in participating the CPUC Order Instituting Rulemaking ("OIR") to Modernize the Electric Grid for a High Distributed Energy Resources Future, Rulemaking R.21-06-017. The goal of this proceeding is to capture maximum value from DERs and mitigate unintended negative impacts of policies as total installed DERs continue to grow. The Joint CCAs raised three concerns to be addressed during development of the Scoping Memo for this docket: (1) protecting competition and incorporating the reality of competition into the distribution planning process; (2) addressing the need for greater transparency and data access; and (3) maintaining a clear-eyed focus on cost containment. Specifically, they called for greater transparency in distribution planning and access to distribution related data, greater collaboration between local governments, CCAs and IOUs, and for the CPUC to address rising IOU transmission and distribution cost containment as part of the discussion of the value of 3rd party DER.

Ancillary Services

FERC is exploring additional market reforms on potential energy and ancillary services, such as those to increase operational flexibility, that may be needed as the resource fleet and load profiles change over time. In October 2021, FERC held a Technical Conference (AD21-10) on Modernizing Electricity Market Design. As a participant in the Technical Conference, CAISO noted that it is pursuing market changes to more efficiently address net load variability using an imbalance reserves product, to reserve capacity in the day-ahead timeframe to meet net load variability. Additionally, it was highlighted that storage resources significantly increased their footprint in CAISO's regulation service requirements as well as spinning reserves, and flexible ramping capacity. Innovative techniques such as batteries bidding and scheduling themselves to charge themselves to provide resources during peak demand times are expected to transform availability of resources and reliability to the electricity market.

Task 3: Strategic Planning

This section lays out an initial Strategic Plan Framework to accomplish the following objectives:

- Ensure SJCE's Financial Stability
  - Build reserves to 90 days, path to 180 days, obtain a credit rating
  - Provide competitive stable rates, Stay within 5-10% of gen rate, customer savings over the long-term
- Accelerate clean energy goals
- Improve Organizational Effectiveness

3.1 Financial Stability

Ensure SJCE's Financial Stability by

i. Evaluate moving SJCE's rates to cost of service ("COS") rates instead of a percentage of PG&E rates. Identify benefits, risks, the impact to SJCE financial projections, and timeline to implement.
ii. Provide an assessment of SJCE's current strategies to reduce power supply costs and a recommendation of other strategies SJCE should consider. Current strategies include:
    - Improved Energy Trade and Risk Management platform implementation
    - Adding additional medium and long-term contracts
    - Procurement strategy to incorporate higher level of intermittent resources
    - DR and other DER programs
    - Investigate options or insurance to mitigate weather impacts
    - Load shaping through rate design

SJCE's current rate structure contains pegs to PG&E rates versus a COS model. This tie to PG&E rates creates both benefits and presents challenges for SJCE. Among the benefits are:

- **Easy to understand comparisons**. Customers do not need any energy industry expertise to understand the value of lower rates. The peg with a built-in discount to PG&E is a transparent benefit to customers who chose SJCE. Understanding the implications in their bills from switching providers is relatively straightforward.
- **Simplified ratemaking**. With a peg to PG&E rates, the ratemaking process is simpler relative to a full ratemaking procedure that would typically involve opportunities for public input and an extended stakeholder process. Under a peg, the broader ratemaking process would generally focus on rate design changes such as revisions to the discount/premium to PG&E or the product mix (e.g., changing renewable content), and these changes may occur with less frequency in a COS model.

In contrast with a peg structure, application of the COS model potentially provides:

- **Better alignment of financials**. In general, PG&E rates do not appear to have a real connection to SJCE's costs for energy supply. While both are often engaged in the same markets, the timing, volumes, product mix, underlying load, and other factors influencing rates can be quite different and unrelated between PG&E and SJCE. Having SJCE's rates tied to PG&E's rates creates the potential for financial mismatch between SJCE's revenue and costs. Moving rates to the COS model allows SJCE to keep rates aligned to underlying costs. Differences are likely between the rates based on estimated/projected costs and the actual realized costs over time, however, these differences can be relatively smaller when rates are updated with sufficient frequency or when differences exceed a threshold.
- **Local control of rates**. Under a peg, PG&E drives rates and both the magnitude and timing of changes. With the COS model, control comes under SJCE's control. While the underlying costs may be influenced by factors beyond SJCE's direct control (e.g., weather, regulatory changes, macroeconomic and geopolitical events), how those costs filter into rates and the pace at which cost changes impact rates become a local determination. The opportunity for SJCE to simplify rates compared to PG&E is also a benefit. PG&E has multiple rate classes which typically have more factors that affect rates than SJCE, therefore, the ability to keep rates simple and explainable is an advantage. This will be somewhat tempered by potential customer confusion with new rate structure and/or limited impact of novel rate design in that all SJCE customers on an SJCE-specific COS-based rate will remain on legacy PG&E rate for their PG&E energy delivery charges. In addition, customers will want some level of benchmarking of rates to PG&E rates regardless of the method of deriving rates and a long-term expectation of savings relative to PG&E.
- **Local prioritization and customization**. Under the COS model, SJCE can design rates with local priorities in mind, crafting rate structures to address locally determined goals and targets.

There are additional activities SJCE would need to take on when shifting to the COS model

- Full ratemaking process
- Determination of cost and true up

Challenges in the Cost of Supply

Due in part to the customer base and the local microclimate, SJCE load can exhibit demand peaks in response to high temperatures with the rapid addition of demand from air conditioning that under slightly cooler conditions tend to be unnecessary. Because the Santa Clara Valley experiences high temperatures in the summer, the peakiness of SJCE load contributes to a higher RA requirement than would otherwise be necessary. Furthermore, when temperatures are high, CAISO demand is also high. This typically results in higher short-term energy market prices. Therefore, when SJCE must procure additional energy to serve the rapid increase in demand with high temperatures, it must often do so at unfavorable prices. If SJCE were to procure more energy in expectation of high temperatures, there will likely be times when such temperatures are not realized, and SJCE must liquidate the excess energy, also often at unfavorable prices since the lower temperatures likely come with lower CAISO demand and lower market prices.

Load serving entities often have these risk exposures sometimes described as being “short a straddle” because the financial result is similar to the option trading strategy by the same name. Essentially being short a straddle means:

- Needing more quantity when the market is likely to also need more resulting in buying when prices are likely high, or
- Having too much quantity when the market also has too much resulting in selling when prices are likely low.

The potential for peakiness of SJCE’s load mix makes the typical short straddle position of load serving entities all the more challenging when compared to systems with smoother and less variable load patterns. The peaky load and volume/price risks raise several risk management considerations and approaches.

- Enhanced risk measurement and monitor tools. Potential for high volatility makes active monitoring and management increasingly important.
- Consider wider range of risk management instruments
  - Options and other power derivatives
  - Derivatives for other energy types (e.g., natural gas)
  - Weather derivatives

There are several load-shaping strategies that can help to manage peakiness of the system, reduce RA requirements, reduce the short-straddle problem, and mitigate the duck curve ramp problem.

- Consider deploying load shaping mechanisms such as:
  - Wide use of time-of-use (“TOU”) rates
  - DR
  - Battery storage management
  - Encouraging rooftop solar in combination with storage.

Hedging strategies

- Include a plan to replace Diablo Canyon carbon-free energy well in advance to avoid having market participants drive prices higher ahead of the purchase knowing there will be additional buyers coming to market at a later date, closer to the retirement. Performing scenario analyses, leveraging both historical price data as well as models of forward price curves, can help SJCE evaluate the potential risks and related benefits of hedging strategies. The scenario analysis can also aid the department in evaluating its ability to execute and monitor the level of energy market activity that is anticipated as part of any risk mitigation or hedging strategy. The Department licensed the cQuant platform in July 2021 to enhance their analytical tools. These are currently engaging in configuration, setup and testing of the tool and plan to be complete with those activities by the end of the year. The initial functionality that is out of the box that the Department will utilize is for procurement optimization. SJCE is also working with cQuant.io to develop more sophisticated scenario analysis and hedge analysis capabilities which they can leverage.

One initiative pursued by SVCE, EBCE, MCE, CCCE was the development of a bond conduit for pre-payment structures to potentially reduce procurement costs in forward contracting. The first bonds for the conduit were issued in October 2021. A pre-payment arrangement has the buyer (e.g., SJCE) enter into a long-term purchase, paid up front (hence, pre-payment), for delivery over the contract term. As a municipal entity, tax-free/tax-advantaged bonds can be issued for particular purposes under the federal and state tax codes. These advantages can lower the effective interest rate thereby reducing the funding costs for activities funded by these municipal bonds. One activity is the pre-payment of qualified commodities (e.g., natural gas and electricity) for users in the territory. The tax-advantaged treatment often allows the utility to obtain a discount in the procurement. Municipal pre-payments have been popular for natural gas since the 1990s. The arrangement essentially allows the entity to monetize its tax-advantaged capability through discounted purchase prices. This could be an attractive option for SJCE to reduce or manage procurement costs, though the discount would come with an implied credit risk since a payment would be made for energy not delivered until the future. The direct exposure to SJCE is to the pre-pay intermediary that ultimately executed the long-term pre-pay arrangement with a supplier and collects periodic payments from SJCE for energy while servicing the issued tax-advantaged bonds. Proper structuring of risks and credit terms is important to shield SJCE from undue risk and to mitigate the risks held by the intermediary such as default in delivery of the long-term supplier.

3.2 Accelerate clean energy goals

This section provides an assessment of strategies to accelerate clean energy goals which include strategies to accelerate state objectives and respond to customer demands identified in task 2. There are several studies which cover utility energy transitions and decarbonization, we focus on two here:

Utility decarbonization strategies[87]: Based on a survey of 600 C-Suite executives and other corporate leaders conducted in March 2020 as part of the Energy Transition Study, Deloitte released a report outlining strategies that power and utility companies can implement to assist in decarbonization efforts. Deloitte identified three strategies to help drive utilities' transition to clean energy: *renew supply*, *reshape demand*, and *refuel end uses*.

- **Renew Supply**
    - Retire or retrofit non-renewable plants and capture or mitigate emissions from any remaining fossil-fueled plants.
    - Invest in deploying utility-scale solar and wind energy projects
    - Manage the increasing reliance on intermittent renewables by deploying storage on the grid to provide greater system flexibility
- **Reshape Demand**
    - Use **DR** to avoid carbon-fueled power by shaving and shifting demand
    - **DERs** can be used to reduce demand while also providing utilities with new sources of renewable power
    - Complement the flexibility provided by DR and DERs with utility-driven energy efficiency measures

[87] Utility decarbonization strategies, Deloitte

- **Refuel End Uses**
  - Promote the electrification of the transportation, heating, and industrial sectors to achieve systemwide decarbonization
  - Maximize the use of renewable energy sources and avoid wasteful overbuild by increasing seasonal storage through conversion to hydrogen or thermal fuels
  - For areas that cannot be electrified, it may be more cost effective to transition to carbon-free fuels

Smart Electric Power Alliance's ("SEPA") Utility Transformation Challenge and Report[88]: Utilities are encouraged to focus on four 'dimensions' of the challenge which include *clean energy, modern grid, aligned utilities, corporate leadership*. Their survey and report were informed by responses from 135 individual utilities. Insights from leaderboard utilities (those that have made most progress toward renewables goals) include the fact that it's important to have **explicit commitments** which this leads to more real progress and it's important to have a **comprehensive approach**. These conclusions are seconded by The Natural Resources Defense Council's ("NRDC") *Race to 100% Clean* resource[89], that speaks to the importance of bolstering target year goals, which are usually around years 2040 to 2050, with interim targets around 2030. This report includes an interactive map showcasing utilities' target goals and interim goals across the U.S. NRDC highlights the importance of what baseline year is used in emissions reductions targets, in order to achieve **impactful** and **reachable** emissions reductions goals. Except where otherwise noted, the information below is based off of SEPA's Utility Transformation Challenge and Report.

- **Targeting clean energy**
  - The survey findings demonstrate that utilities, including Leaderboard Utilities**, are not maximizing the potential for demand-side management ("DSM") resources (Energy Efficiency ("EE"), DR, DERs)**
    - Research shows DSM should be incorporated into integrated resource planning
  - Leading utilities in clean energy transition are employing **storage** at a higher rate through **flow batteries, lithium-ion batteries, and pumped hydro storage**
  - Importance of **accelerating carbon reduction targets** and make commitments to carbon reduction beyond owned generation capacity. Leaderboard utilities have adopted a 100% carbon-reduction target that applies to their total retail energy supply, adopted 100% carbon-reduction target that enhanced a previous target, or have adopted carbon-reduction targets with one or more interim targets.
  - Majority of the leaderboard utilities offer **green tariff, community solar, and BTM solar** programs
  - Partnership with customers through **demand flexibility programs**, two-way smart thermostat programs, EV-managed charging program to integrate clean energy, grid-interactive water heater programs to integrate clean energy

---

[88] 2021 Utility Transformation Profile, SEPA
[89] Race to 100% Clean | NRDC

- Leadership utilities are **early adopters of new technology** like grid-interactive efficient buildings ("GEBs")
- Leading utilities **engage all customer classes about transportation electrification programs and are engaging customers** *through early-stage* (educational resources), *intermediate stage* (incentives for EVs and behavioral load-management programs), *and late-stage* residential programs (active load-management programs)
- Utilities need to **bolster low- and moderate-income customers programs** (most only target energy efficiency)

- **Modern grid**
  - Importance of **modernizing the grid through Integrated Distribution Planning ("IDP") practices,** leaderboard utilities have adopted IDP practices at a higher rate
  - Importance of **modeling DER into load forecasting**
  - Importance of **more data automation and coordination** through data to determine or measure EV connections, load disaggregation, visibility of grid operation, and load forecasting and hosting capacity analysis

- **Collaboration/alignment with other utilities and other partners**
  - Leading utilities lead in **strategic investments and collaboration with external partners** to help solve issues with getting to their renewable targets. Examples include operating innovation centers, formal partnerships with Universities, technology partnerships with other companies, providing funding for external technology, utility-owned start up or in-house R&D department

- **Corporate leadership**
  - SEPA recommends more utilities **tie executive compensation to reduced carbon emissions**
  - Transformation of culture through **leadership, transparency, accountability.**
  - **Importance of long-term approach to stakeholder engagement** around clean energy, grid modernization, distribution planning, electrification
  - Utilities are **integrating sustainability planning and transparency into their culture** through publishing sustainability plans and publicly disclosing their emissions
  - **Collaboration with stakeholders** to facilitate transformation**.**

i. Evaluate options and define specific goals for SJCE to consider (i.e., 100% renewable, 100% carbon-free, 24x7 renewable, etc.)
   - **100% renewable**: Achieved by purchasing enough renewable energy to match annual electricity use (reduces emissions)
     - Matches annual electricity consumption with clean energy
     - Increases amount of clean energy on some electric grids
     - Over 300 global companies have joined the RE100 and have pledged to go 100 percent renewable energy no later than 2050

   - **24/7 Renewable energy**: Achieved by sourcing clean energy for every location and every hour of operation whereby eliminating all carbon emissions associated with electricity use and load with 100% clean energy

  - Matches hourly electricity consumption with clean energy which is produced in the same region as it's consumed
  - Directly increases amount of clean energy on all electric grids where a company operates

- **Carbon neutral**: This typically means reducing direct emissions as much as possible through other initiatives (i.e., 100 percent renewable energy) and then turning to other solutions including purchasing carbon offsets for all remaining emissions regardless of their source (i.e., supply chain).

- **Science-based targets initiative**: Science-based targets ("SBT") provide a clearly-defined pathway for companies to reduce GHG emissions, in line with the Paris Agreement goals. Targets are considered 'science-based' if they are in line with what the latest climate science deems necessary to meet the goals of the Paris Agreement – limiting global warming to well-below 2°C above pre-industrial levels and pursuing efforts to limit warming to 1.5°C.
  - As of October 11, 2021, 1,929 have established goals, 973 have SBT and 906 have set the more ambitious goals of 1.5°C[90].

    Setting a science-based target is a five-step process[91]:
    - Commit: submit a letter establishing intent to set a science-based target
    - Develop: work on an emissions reduction target in line with the SBTi's criteria
    - Submit: present the target to the SBTi for official validation
    - Communicate: announce the target and inform stakeholders
    - Disclose: report company-wide emissions and track target progress annually

In the near term, aligning with the City's goal of being carbon neutral by 2030 can make sense for SJCE as other potential strategies are evaluated. If SJCE chooses to align with this goal, there needs to be a clear understanding of its current carbon emissions and position relative to carbon neutrality. A procurement strategy and timeline could then be developed with interim goals for SJCE to stay on track towards carbon neutrality by 2030. With a clear understanding of SJCE's current carbon footprint and the gap between that and carbon neutrality, SJCE will have a better idea of the feasibility of meeting this goal.

Regardless of the goal that is set, the following strategies could help SJCE get there:
- Define a goal boundary as broadly as possible, but don't let perfection get in the way of progress (e.g., include operational emissions only or if possible, expand to include supply chain or purchased energy)
- Collect accurate data pertaining to SJCE's current carbon footprint and which processes affect its carbon emissions
- Consider the activities SJCE may be able to take to reduce emissions within and outside of that boundary before finalizing the goal

[90] Ambitious corporate climate action - Science Based Targets
[91] Ambitious corporate climate action - Science Based Targets

- Consider other criteria that may be important to SJCE, such as job creation, financing, or local impacts
- Set interim targets and engage in other relevant initiatives, such as RE100, or SBTi
- Be transparent about commitments and how to get there
- Track progress publicly and consider third-party verification or certification.
- Implementation strategy and goals should be regularly reassessed as SJCE progresses towards its goals and new technologies emerge

As per the SEPA utility decarbonization tracker, the goals set by utilities in California[92] are summarized in Table 22. Senate Bill 100[93] sets a 2045 goal of powering all retail electricity sold in California and state agency electricity needs with renewable and zero-carbon resources. The clean energy goals for various utilities, summarized below, are in accordance with this law.

Table 22: Clean energy goals of utilities in California

Customer Name	%Renewable energy and zero Carbon resources	Target Year
Pacific Power	100	2045
Pacific Gas & Electric (PG&E)	100	2045
Trinity Public Utilities District	100	2045
Southern California Edison	100	2045
Imperial Irrigation District	100	2045
Sacramento Municipal Utility District	100	2045
San Diego Gas & Electric	100	2045
Los Angeles Department of Water and Power (LADWP)[94]	100	2035

[92] Utility Carbon-Reduction Tracker™ | SEPA (sepapower.org)
[93] https://www.energy.ca.gov/sb100
[94] https://www.dailynews.com/2021/09/01/la-votes-for-100-renewable-energy-by-2035-a-decade-sooner-than-planned/

Table 23 summarizes the clean energy goals set by some of SJCE's comparable CCAs in California.

Table 23: SJCE's comparable CCAs and their clean energy goals

CCA Name	Target type	Target Percentage	Target year
Clean Power San Francisco (CPSF)[95]	Renewable Energy	100	2025
Silicon Valley Clean Energy (SVCE)[96]	Clean Energy	100	2045
East Bay Community Energy (EBCE)[97]	Clean Energy	100	2030
Redwood Coast Energy Authority (RCEA)[98]	Renewable Energy	100	2025
Valley Clean Energy (VCE)[99]	Renewable Energy	100	2030
Central Coast Community Energy (3CE)[100]	Renewable Energy	100	2030

The City of San José's plan to tackle climate change "Climate Smart San José" assumes that SJCE will have a renewable energy mix at least ten percent above PG&E which would mean 60 percent renewably sourced in 2030, and an eventual increase to 100 percent renewable by 2045[101]. Although the end goal in 2045 align across all these utilities, SJCE's current trajectory would put it ahead of target in achieving both the 2030 goal and the 2045 goal. SJCE is currently achieving this through procurement of PCC1 and PCC2 RECs and GHG free attributes. In addition, SJCE has made multiple investments in renewable facilities which will start coming online at the end of 2021 which will also contribute to these goals.

Climate targets were analyzed for a representative sample of companies from the top 25 commercial accounts (in terms of annual load) served by SJCE. Many of these companies had Scope 1 and Scope 2 emission reduction targets and some had Renewable energy (RE) targets which are summarized in Table 24.

[95] https://cleanpowersf-sfpuc-yem2.squarespace.com/resourceplan
[96] https://cal-cca.org/sv-clean-energy-announces-2020-emissions-reductions-and-power-content/
[97] https://ebce.org/news-and-events/east-bay-community-energy-commits-to-100-clean-energy-by-2030/
[98] https://cal-cca.org/redwood-coast-energy-authority-targets-100-clean-and-renewable-electricity-by-2025/
[99] VCE is currently evaluating its goals. https://valleycleanenergy.org/wp-content/uploads/Item-8-Carbon-Neutral-Task-Group-Update-8-26-21.pdf
[100] https://3cenergy.org/understanding-clean-energy/
[101] https://www.sanjoseca.gov/home/showpublisheddocument/32171/636705720690400000

Table 24: Sample SJCE's commercial customers and their targets

Customer Name	%Emission Reduction Target	Target Year	%RE Target	RE Target Year
Equinix Inc.[102]	50	2030	100	2030
eBay Inc.[103]	90	2030	100	2025
Intel Corporation[104]	10	2030	100	NA
Lumentum Operations LLC[105]	100	2030	100	NA
Sprint Corporation[106]	100	2025	100	2025
Federal Realty[107]	30	2025	NA	NA

Intel and Lumentum aim to achieve 100% Renewable energy, but the target year isn't stated for either company. Federal Realty has Electric vehicle ("EV") charging stations installed in 12% of their properties and has plans to expand[108]. SJCE needs to perform further analysis on their commercial customers and their load profiles. Working together with these customers on achieving their sustainability targets could help SJCE further smooth out its evening peak and help SJCE manage its associated RA costs.

ii. This next section evaluates options and SJCE existing programs roadmap to define appropriate electric vehicle, distributed energy resources, and electrification goals and programs to meet these goals.

Overall, the SJCE programs are in line with our expectations and are similar to programs observed for other utilities are considering for implementation or are in the process of implementing. In addition, SJCE should consider the following:

- Customer segmentation, on the residential and business side, when developing and prioritizing pilots, outreach and programs
    i. Research where there is demand for specific programs on an end-consumer basis. SJCE could consider employing surveys to consumers and businesses to understand what services they would be interested in and what SJCE could consider adding to its services or better marketing existing services
- Mechanism for obtaining program feedback

[102] https://investor.equinix.com/news-releases/news-release-details/equinix-sets-2030-global-climate-neutral-target

[103] https://www.ebayinc.com/stories/news/science-based-targets-initiative-approves-ebays-ambitious-goal-to-reduce-scope-1-and-2-carbon-emissions-90-by-2030/

[104] https://www.intel.com/content/www/us/en/environment/intel-and-the-environment.html

[105] https://www.lumentum.com/en/company/corporate-social-responsibility/our-planet

[106] https://www.prnewswire.com/news-releases/sprint-goes-carbon-neutral-and-announces-new-environmental-goals-300958324.html

[107] https://ir.federalrealty.com/news-releases/news-release-details/federal-realty-investment-trusts-2020-corporate-responsibility

[108] https://www.federalrealty.com/wp-content/uploads/2020/04/Federal-2019-Corporate-Responsibility-Report.pdf

- Program success measurement after the fact

Additional observations are as follows:

Pilots and outreach

SJCE currently utilizes websites, events, promotions and workshops to target customers. SJCE may consider increased customization of outreach and continued development of partnerships. The effectiveness of the outreach may be impacted by the means of communication or outreach (i.e., written materials, websites, online platforms, apps etc.) with the customer and the specific messaging. SJCE can leverage its unique position as a Load Serving and City entity to facilitate the adoption of EVs and building electrification in an equitable way. SJCE could improve its current offerings by "filling the gaps" where other entities currently provide services.

Program approach and prioritization

- SJCE currently categories programs over short- and medium-term time horizons and scores programs based on the following criteria: Emissions Impact – Lifetime MT of CO_2e reduced
- Map customers by loading order to better drive consumers toward relevant offerings
- Cost Effectiveness - Dollars spent per MT of CO_2e reduced
- Cost Effectiveness – Program Profit or (Loss)
- Equity - Potential Quantity of Low Income Qualified Residents Impacted by program
- Community Benefits
    - Reduces Air Pollutants
    - Saves customer money
    - Leads to Local Job Growth
    - Educates and Creates Awareness of Climate Solutions

Future programs

SJCE should continue to conduct additional analysis, stakeholder engagement, and program design iterations over the next few years. Following these actions, additional programs could be added or taken out of the program recommendations. Consideration should also be given to changes in technology which may adjust prioritization of these programs as well as programs being added or removed. In the long term, SJCE recommends programs that focus on difficult-to-reach customers and communities to ensure they are benefiting from clean energy, as well as focus on market segments still awaiting the transition to clean energy. SJCE should continue to team with stakeholder groups who may have access or relationships with the difficult-to-reach customers and communities.

3.3 Strategies to improve Organizational Effectiveness

This section aims to provide an assessment of SJCE's current strategies to improve organizational effectiveness. Identify benefits, risks, and timeline to implement. Current strategies include:

3.3.1 Improved financial monitoring and reporting

Additional awareness/communication of existing financial monitoring mechanisms and reporting: The Department should inventory all of the current financial reporting that is being carried out including the purpose of each response, the target audience and the frequency of distribution. They should then consider having a working session with key stakeholders in the City's finance and budget groups to walk through all reports to build awareness and identify gaps, if any. Examples of the type of reports to include would be the reconciliations being done between the budget, the proforma and accounting actuals.

Increase awareness/communication of City reporting needs: The City should discuss and describe expectations of the typical monthly cycle of reports from all Departments. This should allow both sides to understand areas where SJCE can modify their reports to feed into the City reporting framework as well as areas where City can understand specific SJCE nuances that would necessitate where SJCE may deviate from standard City financial reporting.

These full set of reports should then tie to a hierarchy of reporting cadence from the ROC down through management and staff.

The Department should review the current ROC agenda topics and consider adding discussion of commodity market and credit risk topics on a regular basis. Based on our review, there is currently a power procurement details package and credit package shared which are placed on the consent calendar. In addition to being placed on the consent calendar, we would recommend that the ROC agenda include a brief overview of power procurement activities, credit risk management activities and key financial metrics of the Department. Over time, this will foster broader understanding and more fulsome communication of market risks and the corresponding Department risk management strategies among the ROC, staff, Department management, and by extension, the City.

3.3.2 Improved financial projections and modeling

The purpose of the SJCE proforma should be clarified. It is our understanding it is being used as a forecasting/projection tool based on the latest information at any given point in time. There are also versions of it saved for posterity. By its nature, it is intended to be dynamic. However, there should be some level of controls on inputs into the proforma and methodologies for key variables. The number of folks having the ability to 'write' values into the proforma should be limited. In addition, a change in methodology of inputs such as the prices curves should be assessed and based on the impact should be discussed and approved by the ROC.

SJCE should consider enhancing its stress testing and scenario modelling capabilities. By applying stochastic analysis to stress test the portfolio so that the Department can make more informed decisions; Consider employing measure such as 'gross margin @ risk', 'cash flow @ risk' and/or 'budget

@ risk'. These @ risk measures quantify performance relative to plan and the likelihood of meeting the specific targets (gross margin, cash flow and/or budget), and the potential risk to that plan. They incorporate changes in market conditions and risk and would be inclusive of any hedges placed. A benefit of using these is that they provide a risk adjusted view of performance and an early warning when risk threatens objectives. However, they do require a risk engine and can be manually intensive; in addition, they require some analytics capabilities to interpret and review results.

In addition, SJCE should consider developing robust hedge scenario analysis capabilities. As discussed previously, the Department has licensed cQuant to assist in this type of analytic activity. SJCE management should get direction from ROC in terms of risk appetite and hedge program objectives and then execute with a clear risk policy that aligns to that appetite and objectives. Additional resource and system capabilities discussed in 3.4 may be needed to enable these processes.

3.3.3 Improved contract management process and procedures

The Department should document the end-to-end contract management process. Based on our interviews that the process is not well understood end-to-end by all stakeholders. Aligning on the end-to -end process will help SJCE identify people, capability and system gaps.

3.3.4 Increase agility and ability to pilot, learn, and implement

Increase cross group training to filter additional power market knowledge throughout the Department. This will shore up existing staff capabilities and provide ability to grow into different roles.

Enhancing and streamlining reporting internally within the Department and then to the ROC and the City will increase agility and alignment to potentially improve the quality and speed of decisions.

3.4 Additional Strategies

This section aims to identify any additional strategic initiates that would provide high value to SJCE.

In the short term, SJCE should continue to focus on building up reserves so that the overall health of the Department improves and that they are able to meet their commitments to repay the loan they received through the City. In addition to facilitate this apart from shifting to cost of service rates as previously discussed, the Department should limit expansion of any new programs which would require any significant outlay from the Department. The Department can continue to leverage other sources of funding to maintain and/or supplement programs where appropriate.

The Department should consider increasing their letter of credit to be able to hedge their power costs (Brown power, RA and RECs) at a greater coverage ratio further out into the future given that forward prices in future years are lower than current prices. This will lead to cost certainty and in turn potential rate certainty for customers.

The strength of the balance sheet and overall credit quality will determine the amount of unsecured credit a counterparty will grant. The Department should consider pursuing their own stand-alone credit rating to potentially lower their future borrowing costs. Currently, since all of SJCE's procurement contracts include language limiting obligations to SJCE, the Department, rather than the City, counterparties want to assess SJCE's financial position in reference to credit terms. Once a stand-alone credit rating is established, the need for additional documentation in credit discussions with each counterparty and increased collateral would diminish.

A non-exclusive list of counterparty underwriting considerations will include:

- Types of transactions (i.e., physical vs financial)
- Tenor of transactions
- Liquidity of regions transacted in with particular counterparty
- Volatility of the underlying commodity price

As part of increasing credit capacity, it will be important to continue to carefully model, with stress considerations for volatility and tenor, the anticipated SJCE cash flows. This is because with increased fixed price arrangements and added tenor, Mark-to-Market exposure will likely increase. While not unique to SJCE, estimated collateral requirements should also be carefully factored in risk/return assessments of the business given their direct cost and impact on corporate liquidity.

The Department would benefit from targeted increases in staffing and infrastructure in the market risk area to be able to support the evaluation and possible execution of additional risk mitigation or hedging strategies. We are aware that peer companies have been exploring the benefit of certain risk management products, including financial instruments and derivatives, and implementing more proactive commodity hedging and transacting capabilities. These strategies can prove to be effective components of risk management programs, provided that the appropriate governance, process, and control practices are in place to measure and monitor the activity relative to the program objectives and organizational risk appetite. Financial hedging strategies, and the use of derivatives, can provide tangible benefits for the stakeholders and customers over time, but the decision to implement such a program should be based on rigorous examination of the program objectives, associated risks, and infrastructure requirements to support it. In our experience, an effective approach to such an evaluation should include:

- Clear organizational alignment and articulation of the program's risk management objectives. Multiple objectives should be identified and examined and can include achieving a certain budget for power supply costs, mitigating power cost volatility, mitigating customer rate increases, or avoiding accounting losses related to hedge positions. Once a set of objectives is identified, the organization should also align on the risk appetite related to those objectives. That is, how much variation are we willing to accept related to each objective, and what trade-offs are we willing to accept in achieving those objectives?
- Once the objectives and risk appetite are defined, robust quantitative simulations should be performed to evaluate the effectiveness of various hedging / risk management strategies against those objectives. Leading practice in this regard is to deploy a monte-carlo based simulation technique to model the various strategies, using historic time periods and actual prices to simulate the execution of the strategy. The output of the simulation can then form the basis of a robust discussion among stakeholders as to the preferred strategy going forward. Considerations should also include an assessment of the people, process, governance,

and technology capabilities that will be required to implement the strategy. Through the use of simulations, the organization can also align on the level of complexity of the program, the use of derivatives or options, and the frequency of transacting that will be required.
- Prior to implementation of any hedging or risk management strategy, the Department should ensure that any capability gaps identified during the simulation are addressed. This would also include necessary updates to governing risk policies (for example, clearly defining authorized instruments, transacting personnel, risk metrics) and enabling technology. Addressing these processes, governance and technology gaps, to the satisfaction of Department management and the ROC, is a prerequisite before implementing the hedge strategy and transacting activity.

If SJCE decides to ramp up hedging/power marketing activity in-house, it will be even more important to clearly establish and maintain organizational segregation of duties, in particular, the segregation between front office (transaction execution) and middle /back office (risk oversight and accounting). Relatively small organizations have successfully implemented these hedging programs while maintaining segregation of duties. Often, a strong process and control environment can be promulgated through the implementation of an Energy Trading and Risk Management ("ETRM") system to manage the front, middle and back office lifecycle of the commodity transacting activity. A number of ETRM vendors offer cloud-hosted and scalable solutions that can be designed to be fit-for-purpose for the department's expected level of activity and can provide key reporting functionality to help ensure transparency and appropriate risk oversight. The Department has licensed cQuant for portfolio optimization activities which are part of the procurement planning process and is used prior to transaction execution. ETRM systems help track transacting activity after the fact from transaction lifecycle perspective including transaction capture, trade confirmations, market and credit risk and settlements of the transactions. They assist in systematically processing transactions end to end thereby reducing the reliance on spreadsheets and the manual effort of tracking and reporting on transacting activity.

Given some of the challenges of recruiting and retaining this specialized skillset, SJCE should consider outsourcing market risk capabilities until capabilities can be brought in house.

SJCE should consider of an overall hedge strategy analysis, as part of the scenario analysis using different hedging timelines, use of derivatives / financial instruments, different risk tolerances. This will provide more perspective on the potential risks/benefits of different strategies and deciding if SJCE wants to keep pursuing their current hedge strategy or make adjustments to plan.

SJCE should actively monitor its commercial customer base which may be more sensitive to rate changes when compared to residential customers and explore additional ways to increase their stickiness. As part of a move to cost of service rates, the Department may be able to provide increased rate predictability to commercial customers thereby enhancing their stickiness. These customers potentially have additional choices in the form of Direct Access eligibility. In its latest Staff report on DA and its' as well as June 24, 2021 Decision (D. 21-06-033), the CPUC has not recommended further opening up DA at this time. A joint petition for a rehearing of the Decision was issued by several ESPs in July 2021, which CalCCA did not support. The CPUC has taken no action on this so far.

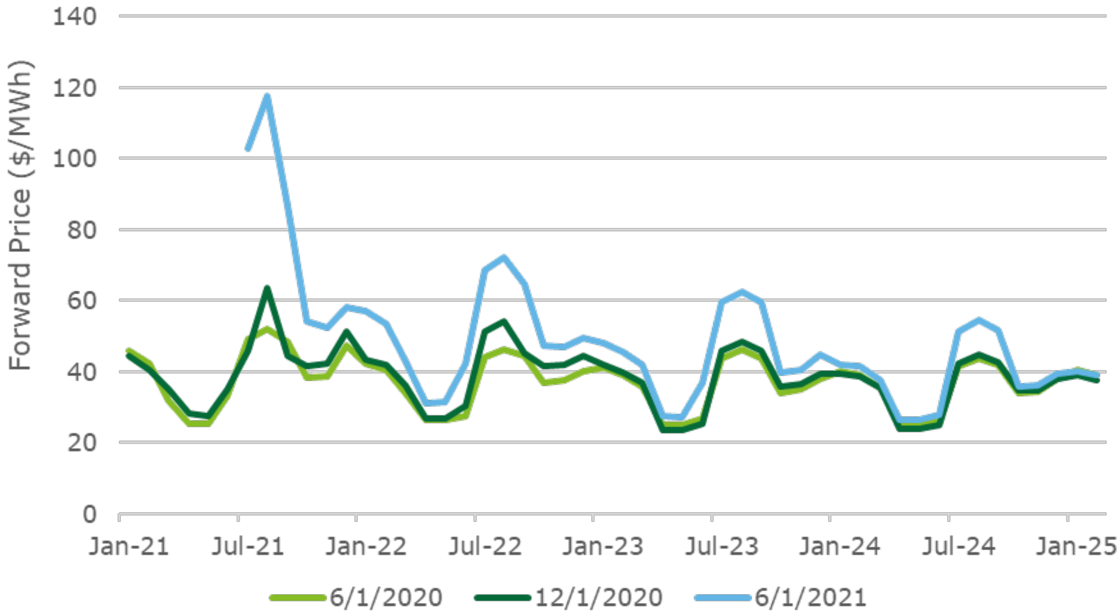
3.5 Strategy Impacts

Among the strategies suggested in this report is to consider expanding flexibility in hedging. Broadly speaking, hedging involves managing risk by taking positions to offset the risk of other positions. As a LSE, SJCE is "naturally short[109]" electricity, that is, SJCE benefits financially when the price of electricity declines. The traditional approach to hedging this short exposure is to take offsetting long positions such as the purchase of power for forward delivery. By power purchases through forward contracting, the volume of expected load covered by the contract is no longer subject to market prices. SJCE, like many utilities, regularly contracts for differing quantities of power to hedge along their future load exposure, usually contracting greater volumes for near-term delivery and lower amounts for deliveries further into the future.

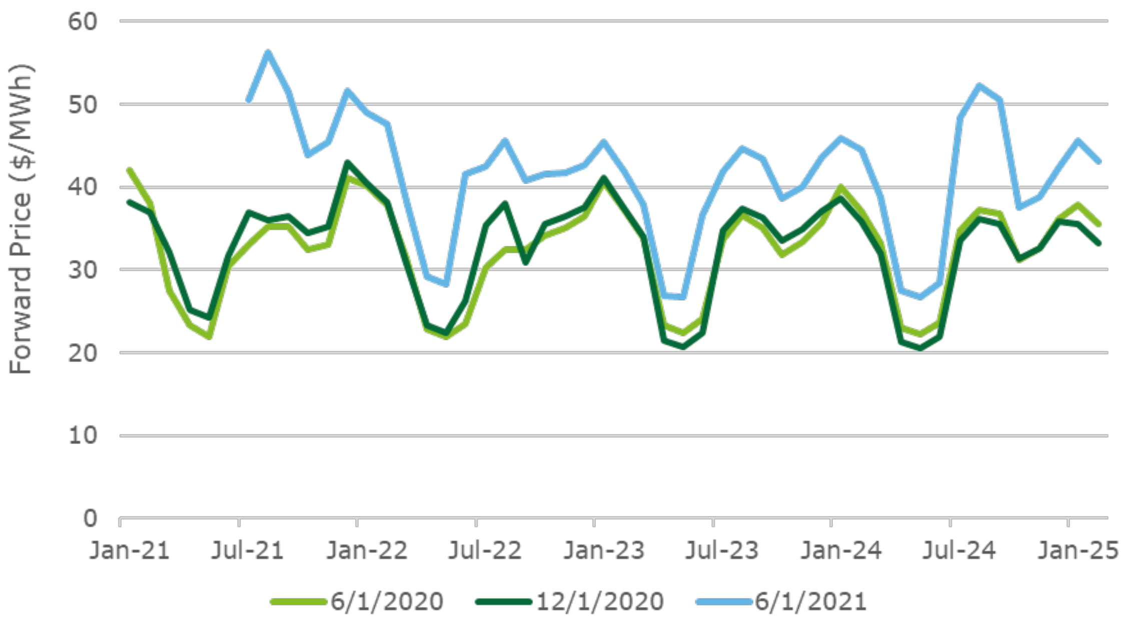
Forward Contracting

The forward curve provides valuable information on the prices of power on a given as-of-date. Figure 21 illustrates the CAISO NP15 Peak power forward curve on three different as-of-dates, each six months apart. While forward peak prices between June and December of 2020 are relatively similar to each other, by June 2021, the forward curve had shifted higher, particularly for summer delivery, and more so in the "front" months that are for closer delivery relative to the "back" for later delivery.

[109] In trading, a position that gains in value with an increase in the price of a commodity is characterized as "long" with respect to that commodity. Conversely, a position that loses value with an increase in the price of a commodity is characterized as "short" with respect to that commodity. Generators are long electricity because they benefit from increases in electricity prices, whereas load is short electricity because the load benefits from a decline in electricity prices.



A similar situation occurred for the off-peak, as illustrated by Figure 22. As with the peak curves, the off-peak curves as-of the beginning of June and December in 2020 were both similar, while the off-peak curve by June 2021 was higher. Volumes hedged (contracted) during 2020 would generally have been done at lower prices than if they had been hedged in mid-2021. This applies whether hedging just one year forward or hedging all the way to 2025 (or beyond).



Based on the uncontracted volumes in the Pro Forma model configured for data around November 8, 2021, the cost of hedging the open CY2023 power position in June 2020 would have increased by about $500,000 by December 2020. By June 2021, the cost to hedge increased another $4.2 million. CY2025 volumes at the start of June 2021 would have cost over $18 million more than if the volume were hedged just six months earlier in December 2020. A major driver of the higher impact for hedging 2025 versus hedging 2023 is the larger open volume for 2025. It is common in hedging strategies to hedge greater volumes closer to delivery and leave larger volumes further out on the curve.

Transacting further into the forward curve increases the potential risk since there is more time for disruptions to occur (or more time for current and near-term issues to be resolved favorably). This higher potential for outcomes different from the current price and outlook causes an increase in credit risk. Therefore, transacting for 2025 in 2020/2021 will carry higher credit demands than transacting for 2023 from the same point in time. Pursuing a strategy to capture the potential upside of transacting further forward should have a higher expectation of credit support.

Scenarios 1 and 2: Forward Contracting

The potential financial implications of different forward hedging plans can be modeled as part of the analysis of hedging strategies. Working with SJCE, two hedging scenarios were developed and are presented here as illustrative examples. Both scenarios consider a time horizon through CY2025, though the underlying hedging transactions may extend much longer. The examples were based around general Pro Forma model data used in the previous swaps example, and all of the values are subject to change. Additionally, how prices, demand, and other quantities turn out in the future cannot be known in advance, so any projections shown are subject to those changes along with others. Scenario 1 assumes the following:

- GreenSource (65% renewable content for calendar 2024 and 2025) carries a 4% premium to PG&E's standard product
- GreenValue is at parity with minimum renewable content of 44% and 46.8% across 2024-2025 respectively
- SJ Cares customers receive a 5% discount to GreenSource
- Energy contracted procurement is the same as recent quantities
- RA prices updated from recent PCIA model
- RPS – PCC1 is modestly lower in 2024-2025 versus 2022-2023

While Scenario 1 uses the current contracting (hedging) schedule, Scenario 2 applies a hypothetical power purchase agreement (PPA) to increase the contracted volumes (and reduce the market risk exposure). The PPA applies for 10 or more years but is only modeled for the periods 2024-2025 and is based around solar supply of approximately 150 MW and a comparable capacity of 4-hour battery storage. Table 25 shows a comparison of selected values between the two scenarios.

Table 25: Comparison of Scenarios with Current Hedging and Hypothetical PPA

Modeled Values ($ million, except where noted)	**Scenario 1**		**Scenario 2**	
	2024	**2025**	**2024**	**2025**
Energy + CAISO ($/MWh)	46	44	44	40
CAISO Cost	17	13	17	13
Contracted Energy Cost	80	67	87	88
Uncontracted Energy Cost	88	96	73	60
Total Energy Cost	185	177	178	161
RA Unit Cost ($/MWh)	*16*	*16*	*15*	*14*
RA Cost	63	65	59	57
RPS/GHG Free Contracted Cost	0	0	0	0
RPS/GHG Free Uncontracted Cost	6	6	2	2
RPS/GHG Free Total Cost	6	6	2	2
Net Income	36	61	52	89

Total costs may be affected by rounding.

One major impact of the PPA is to shift volumes from the Uncontracted Energy category to the Contracted Energy category, with the energy volumes derived from inputs such as the solar capacity, expected capacity factor, potential battery charge/discharge behavior. Another impact flows from the RA requirement as the battery reduces the underlying RA need which in turn lowers the associated costs. The energy from the PPA would be produced by solar, so RPS/GHG Free requirements from the market are reduced. The modeling of the potential price and cost are affected by the assumptions and the realized impact on costs and net revenue can be affected by the actual price variations in the market, the realized weather and solar generation, and other uncertainties. The scenario comparison is intended to illustrate the possible result from entering into the hypothetical transaction, and for a real, live transaction, similar analyses including probing the impact of uncertainties can help reduce the risk of the transaction and increase confidence in any investment decision.

Option Contracts

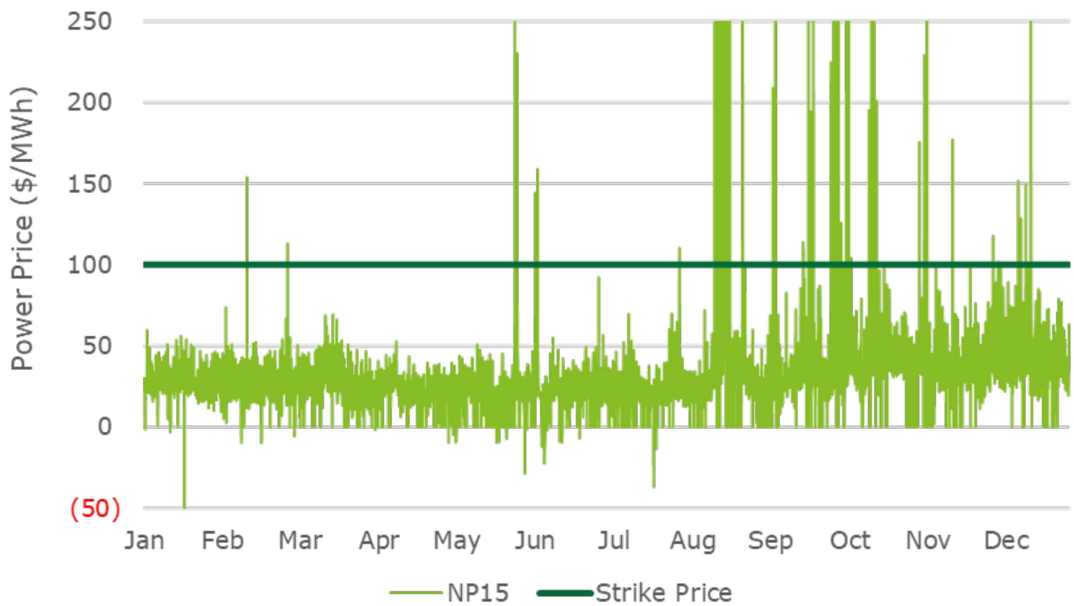
In several contexts, this report has suggested the wider consideration of derivative instruments such as power swaps and options as well as weather derivatives. These financial instruments represent additional tools for risk management. As the name suggests, the value of a derivative instrument derives from another instrument called the underlying.

While derivatives themselves have acquired a negative reputation in some contexts and recognizing they are not available to SJCE at the current time, they as a class of instruments should be considered as a way to broaden the risk management toolbox. Many of the risks and bad outcomes that contributed to the negative perception of derivatives can be properly managed with appropriate oversight, guidelines, and understanding. They can offer some advantages worth considering.

Consider a call option wherein the holder of the call option has the right, but not the obligation, to purchase the underlying for a fixed price (called the strike price) before or at a particular point in time (called the expiration). In the case of a power call option, the value of the option depends on the price of power (the underlying) and other parameters such as the strike price and time to expiration. A call option may be useful to limit the price SJCE must pay for power, since by exercising the option, SJCE can obtain the power at the strike price instead of the market price. SJCE would only wish to exercise the option when the market price of power is higher than the strike price.

Figure 23 illustrates the realized historical CAISO NP15 price against a hypothetical strike price of $100/MWh. If one had an hourly option, hourly prices above the strike price line would be capped at $100/MWh, instead of reaching over $1,000/MWh in some hours, going off-scale in the figure.

Figure 23: CAISO NP15 Hourly LMP for 2020 vs. Strike Price at $100/MWh



Because an option only pays out in favor of the holder, there will be a price associated the purchase of an option. The purchase price is called the premium. Options can be structured in different ways such as applicable for an entire month, applicable for the peak-hours of a given day (or month), or for any series of hours over a range of time. An option that is highly targeted, such as a call option for any hour in August, would carry a very high premium if it is even offered. Seeing the potential payout of an hourly $100/MWh strike option in the example above, it is not surprising that such instruments are not routinely offered.

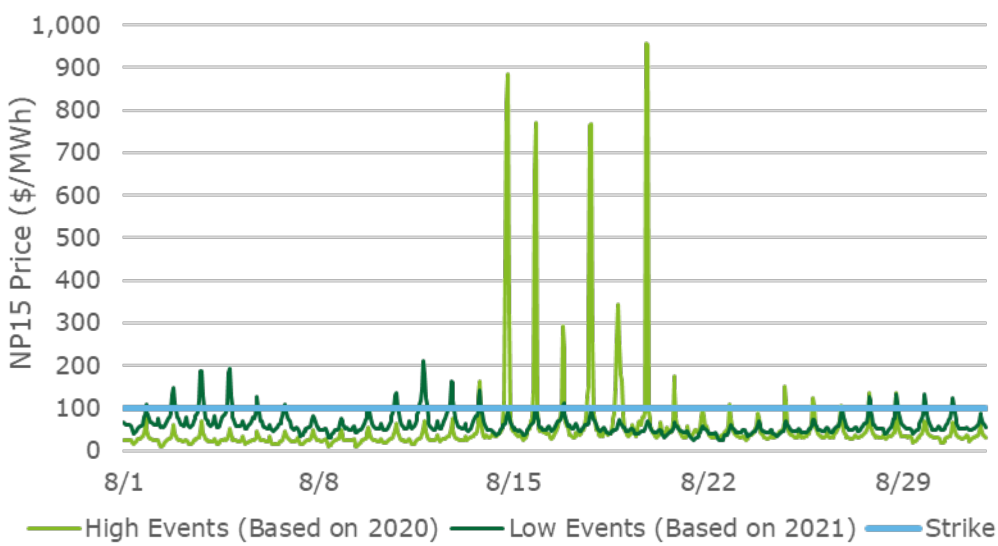
In the case of a call option, a lower strike price also carries a higher premium relative to a higher strike price call option, all other option terms being equal. The amount of protection against adverse price moves relative to the option premium is a major element of risk management strategy. In many cases, the premium for a summer call option can be quite high, so viewing as insurance may be the more appropriate lens for that application.

Scenario 3: Call Option

Consider the hypothetical purchase of power call options for August 2024, a month where a heat wave could send market prices soaring. A relatively available option is the financially settled CAISO NP15 daily peak option. In the case of the August call option, the holder effective has a set of options, one for each peak day of the month. A strike price of $100/MWh means the option would pay the holder when the average of the 16 peak hours for the day exceeds $100/MWh. If the average peak price of power during an hour in August 2024 were to rise above the strike price, the holder of the option receives the difference of the higher market price and the strike price.

How would such a position perform if the pricing in August 2024 turned out to repeat the prices observed in August 2020, when CAISO experience price spikes and rolling blackouts? There would be 5 days "in-the-money" where the average NP15 price during the peak hours of the day would have cleared above the $100/MWh strike price. The payout would be almost $306/MW. With a single option contract size of 25 MW, this would total almost $122,000. During the other 22 days during August 2024, NP15 prices would be below the strike price and the option would provide no payment.

If the August 2024 prices turn out to replace the August 2021 NP15 prices, the option would not have been in-the-money at all. The payout of the option is clearly highly dependent on how market prices clear when the time comes, but the payout of the option, when used in a portfolio of positions, should not be considered alone. The $122,000 payout in the 2020 replication scenario should be considered with the uncontracted exposure (perhaps also 25 MW), in which case the uncontracted market purchase would be higher by $122,0000 due to the spikes. The option in that case did not produce a net windfall, but it did limit the cost of the uncontracted market purchases to $100/MWh on average for several of the highest priced days. Figure 24 illustrates the simulated NP15 prices for a High Events August (based on August 2020) and a Low Events August (based on 2021), as compared to the $100/MWh strike price.



One should recognize that market liquidity can be limited in power options. As of late 2021, August 2022 call options for peak power in CAISO NP15 are not generally quoted. August 2022 is usually more often in a so-called "package" that include the three months of the quarter as a combination rather than the individual month. As time progresses and August 2022 approaches, the quarter package will divide into individual months, but even then, the range of strike prices and the size of the premium may not match SJCE's preferences. For example, there may be no offer for a $200/MWh strike price call and instead $100/MWh may be the highest strike price offered. For example, in July 2021, there were no $200/MWh strike calls offered for August 2021. Daily call options for the month of August 2021 shortly before the month with a $100/MWh strike were offered in the neighborhood of $47/MWh per day. A single contract would cost 25 MW x 16 hours x 26 days x $47/MWh, or $488,800. With a payout of only $122,000 if August 2020 prices were to replicate, the option at that price would not have netted a profit. The purpose of purchasing a call option may be more or separate from simply making a profit on that instrument, so even though a call option in summer may be expensive, it may still be of value, or be of value at a lower premium.

Other Considerations: Swaps

Another approach to contracting for future power deliveries uses a financial instrument called a swap. With a financial swap, the buyer (SJCE) would receive a cashflow based on the index price (e.g., NP15) and pay a cashflow based on a fixed price. As SJCE buys energy from the market (paying NP15 prices, for example), the cashflows of the swap would offset the NP15 price and leave SJCE paying the fixed price. From a financial perspective, the swap combined with the uncontracted market purchases look like contracted purchases at the fixed price of the swap.

While a swap can provide similar financial performance to other forward power contracting such as PPAs, understanding the differences between them is important. When executing a PPA directly with a renewable energy facility, the buyer (SJCE) would ultimately receive energy over the duration of the PPA, usually 10 to 20 years. The PPA would be negotiated and there would be additional time between PPA execution and when the first MWh is delivered. The use of shorter-duration swaps can contract portions of the expected load without taking on sizes associated with a full facility or with durations associated with generation asset lifetimes.

The PPA volumes may be tied to the real physical generation which cannot be precisely predicted far in advance, though swap volumes are typically a fixed value set at inception. The PPA would have a duration of a decade or longer, whereas a swap can be as short as a month. Entering into a PPA takes direct negotiation with a relatively long process and lead time, while a swap can be executed in minutes. Exiting a PPA during the contract life can be complex with limited options, but a swap can generally be sold into the market quite rapidly. The speed of execution of a swap can allow for SJCE to capture the value, while waiting to negotiate a PPA, a transient pricing opportunity is likely to pass.

The preference for facility-oriented PPAs is reasonable, and derivatives can augment the strategy, rather than replace it. (Also, per SB 350 LSEs like SJCE have State-mandated requirements to procure a percentage of their RPS requirements through long-term PPAs. Beginning in 2021 65% of RPS procurement must come from contracts of 10 years or more). While a PPA is being executed or during the time for construction, a combination of an energy swap and tradeable RECs can replicate the output of the facility, essentially moving the effective date forward. If there were a delay in the online date, the swap and REC purchase for just the period of the delay could be executed to mitigate the impacts of the physical delay, and if everything comes online faster than expected, the unneeded positions can be unwound (sold) into the marketplace.

Derivatives can bring choices for faster execution, shorter commitment, more flexible unwinding that can work in combination with PPA and other procurement strategies. Clear risk management guidelines, risk measurement, and operational oversight are also necessary infrastructure to ensure that the use of derivatives are well understood and properly safeguarded. In that way, they can be a valuable addition to the overall risk management toolset.

Appendix

Appendix A: List of SJCE's Documents Reviewed

#	Document Description	Link if any
1	SJCE's current Governance and Operating structure	Link 1
2	SJCE's current Organizational chart	
3	SJCE's current energy risk management policy	Link 3
4	Training documents for financial models	
5	SJCE's load, number of customer accounts served in 2018-2020, rate plans/classes, and participation rates	
6	SJCE's actual power supply costs in 2018-2020	
7	SJCE's actual power mix for 2018-2020 (percent RPS & carbon-free)	Link 7
8	SJCE's GHG reductions for 2018-2020	Link 8
9	SJCE's rates and savings to customers for 2018-2020	Link 9
10	SJCE's financial position for the fiscal year ended June 30, 2021	Link 10
11	SJCE's projections on the amount COVID debt relief expected from state funding and internal collection efforts	
12	SJCE rate class comparison for all SJCE rate changes from 2018 to now	
13	SJCE's Community Choice Aggregation Business Plan, 2017	
14	SJCE programs roadmap	
15	Memo to Transportation and Environment Committee, February 21, 2020; Subject: Community Energy Programs Roadmap Update	

Appendix B: List of Interviewees

Title	Name
Community Energy Department	
SJCE Department Director	Lori Mitchell
SJCE Assistant Director	Zach Struyk
Power Resource Division	
Deputy Director of Power Resources	Jeanne Sole
Principal Power Resources Specialist	Paul Innamorato
Senior Power Resource Specialist	Phil Cornish
Power Resources Specialist	Kelly Morris
Risk Management Contracts & Administration Division	
Staff Specialist of Contract and Administration	Angela Sato-Anderson
Budget and Financial Planning Division	
Division Manager of Budget & Financial Planning	Allen Fong
Program Manager	Ross daSilva
Senior Accountant of Budget & Financial Planning	Jennifer Stevenson
Regulatory, Legislative & Compliance Division	
Division Manager of Regulator, Legislative & Compliance	Kari Smith
Account Management, Marketing & Public Affairs Division	
Deputy Director of Account Management, Marketing & Public Affairs	Joe Flores
Public Information Manager of Marketing & Public Affairs	Kate Ziemba
Analyst of Account Management	Marcos Santiago
City of San José	
CSJ City Attorney Office	
Senior Deputy City Attorney	Luisa Elkins
Deputy City Attorney	Lynne Lampros
CSJ Finance Office	
Director of Finance and Member of ROC	Julia Cooper
Financial Analyst	Prachi Avasthy
Assistant Director Finance	Luz Cofresi Howe
Former Assistant Director Finance	Lisa Taitano
CSJ Budget Office	
Budget Director and Member of ROC	Jim Shannon

Senior Budget Analyst	Tresha Grant
CSJ Risk Management	
Risk Manager and Member of ROC	Miguel Bernal
Other	
Clean Energy Community Advisory Commission ("CECAC") Chair	Daniel Zazueta
CECAC Member	Ruth Merino