DRAFT FINAL

Feasibility Study: Community Choice Aggregation for the City of Los Banos

Prepared by:

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About MRW

This report was prepared by MRW & Associates LLC, led by Principal Mark Fulmer. MRW has provided energy consulting and rate forecasting services to California and other Western state agencies, cities, counties, businesses, trade organizations and consumer advocates since 1986. MRW has been working on Community Choice Aggregation (CCA) issues since they were authorized by the California State Legislature in 2002. MRW has prepared CCA Feasibility Studies for a coalition of Southern California Cities (2008), Alameda County (2015), Contra Costa County (2016), the City of Corona (2018) and the City of Long Beach (2019). MRW also prepared the Business Plan (2018) and Implementation Plan (2019) for what has become San Diego Community Power. MRW has also prepared peer reviews of CCA Feasibility Studies (such as this one) and Risk Assessments for over a dozen jurisdictions considering forming or joining a CCA.

MRW staff, including Mr. Fulmer, were key witnesses at the California Public Utilities Commission in the proceeding that set the rules of conduct that govern the relationships between CCAs and their host utility. In addition, Mr. Fulmer has served as an expert witness before the Public Utilities Commission in every proceeding that has addressed the Power Charge Indifference Adjustment (PCIA) rate as well those that set the CCA financial security requirement and the fees that Pacific Gas & Electric can charge to CCAs for metering and billing services.

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List of Acronyms

AB	Assembly Bill
BNI	Binding Notice of Intent
CAISO	California Independent System Operator
CalCCA	California Community Choice Association
CAM	Cost Allocation Mechanism
CARB	California Air Resources Board
CCA	Community Choice Aggregator/Aggregation
CCEA	California Choice Energy Authority
CEC	California Energy Commission
CPE	Central Procurement Entity
CPM	Capacity Procurement Mechanism
CPUC	California Public Utilities Commission
DA	Direct Access
DEG	Distributed Energy Generation
DOE	Department of Energy
DR	Demand Response
ESP	Energy Service Provider
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GTSR	Green Tariff Shared Renewable
GTSR-GR	Green Tariff Shared Renewable - Green Rate
GWh	Gigawatt Hour
IOU	Investor Owned Utility
JPA	Joint Powers Authority
kWh	Kilowatt Hour
LSE	Load Serving Entity
MCE	Marin Clean Energy
MW	Megawatt
MWh	Megawatt Hour
NEM	Net Energy Metering
PCE	Peninsula Clean Energy
PCIA	Power Charge Indifference Adjustment
PG&E	Pacific Gas & Electric
POLR	Provider of Last Resort
PPA	Power Purchase Agreement
PV	Photovoltaic
RA	Resource Adequacy
REC	Renewable Energy Credit
RFP	Request for Proposal
RPS	Renewable Portfolio Standard
SB	Senate Bill
SC	Scheduling Coordinator

Executive Summary

Based on the scope of work and input from Los Banos and Peninsula Clean Energy (PCE), this study:

- Quantifies Los Banos's electric loads
- Compares the rates that could be offered to Los Banos customers by Peninsula Clean Energy relative to PG&E's rates
- Quantifies the financial impact on PCE of adding Los Banos' load
- Discusses, and where possible, quantifies, the risks to Los Banos and its residents and businesses of joining or forming a CCA
- Compares the benefits and risks of forming a city-only CCA versus joining PCE

Main Findings

The general conclusions of this study are as follows:

1. Los Banos's load is about 5% of that of PCE. As such, the impact of adding Los Banos on PCE's finances and operations would be modest.

2. The analysis performed here finds that adding Los Banos to PCE would be financially beneficial to Los Banos. PCE could likely continue to offer its customers, including Los Banos's businesses and residents, a five percent reduction off of their PG&E generation rate. This translates to about a 2.5% savings off of their overall electricity bills.

3. Over the longer term, PCE would also benefit by adding Los Banos. However, the benefits are not immediate. There would be net costs to PCE over the first few years before the benefits of adding Los Banos materialize.

4. There are risks to Los Banos to joining PCE, in addition to potential benefits. If, for whatever reason, PCE could not offer lower rates than PG&E, customers would experience increased cost due to higher electric bills. Furthermore, if Los Banos chose to leave PCE after it began serving the City, Los Banos could be still be financially liable for some administrative costs and any long-term power agreements executed by PCE after the City's load had been added.

5. Los Banos's two primary options for CCA are forming a City-only enterprise or joining with an existing Joint Powers Authority (JPA) such as PCE. The primary benefits of forming a Los Banos-only CCA are more local control over procurement practices and budgets and services better tailored to Los Banos. However, forming a stand-alone CCA would be likely more expensive, expose the city to greater risk, and would require significant staff for and resources. The primary benefits of joining an existing CCA are the security and reduced risk of joining an already-operating entity, likely lower costs because of economies of scale, and reduced cost and administrative burden on City Staff, both in CCA formation and in ongoing management.

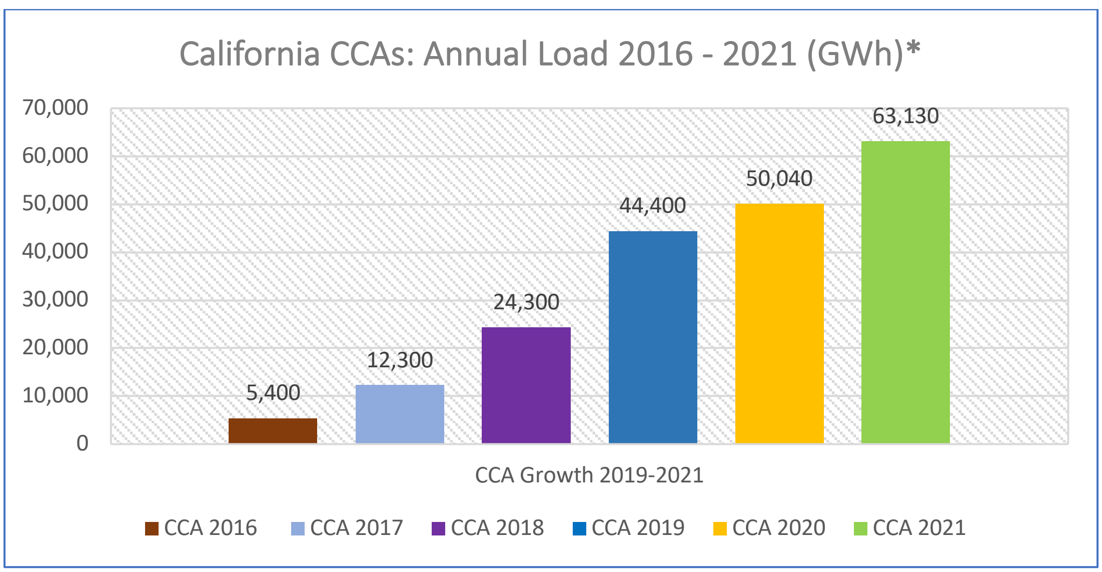
6. Joining PCE is the quicker and simpler route to CCA service for the City. Given the economies of scale gained by joining PCE, it would also likely result in lower power rates for the City, its businesses, and local residents. While joining another operating CCA may be feasible, it could likely not occur until 2023.
7. Joining PCE would also allow the City to receive power from the Wright Solar Park, located in Los Banos.

CCA Background

California Assembly Bill 117, passed in 2002, established Community Choice Aggregation in California, for the purpose of providing the opportunity for local governments or special jurisdictions to procure and provide electric power for their residents and businesses. Under existing rules administered by the California Public Utilities Commission (CPUC), an investor-owned utility (IOU), such as Pacific Gas & Electric (PG&E), must use its transmission and distribution system to deliver the electricity supplied by a CCA in a non-discriminatory manner. That is, it must provide these delivery services at the same price and at the same level of reliability to customers taking their power from a CCA as it does for its own full-service customers.

CCAs are now quite common in California. There are currently 21 CCAs providing power in the State, with at least another half-dozen planning on doing so in the next two years. As shown in Figure ES-1, by 2021, CCAs are expected to serve over 63,000 GWhs in the State, with some projecting that by the mid-2020s, between 50 to 80 percent of the load in the three main IOU service territories will be served by non-utility entities (CCAs and Direct Access providers).

Figure ES-1. California CCA Load Growth[1]



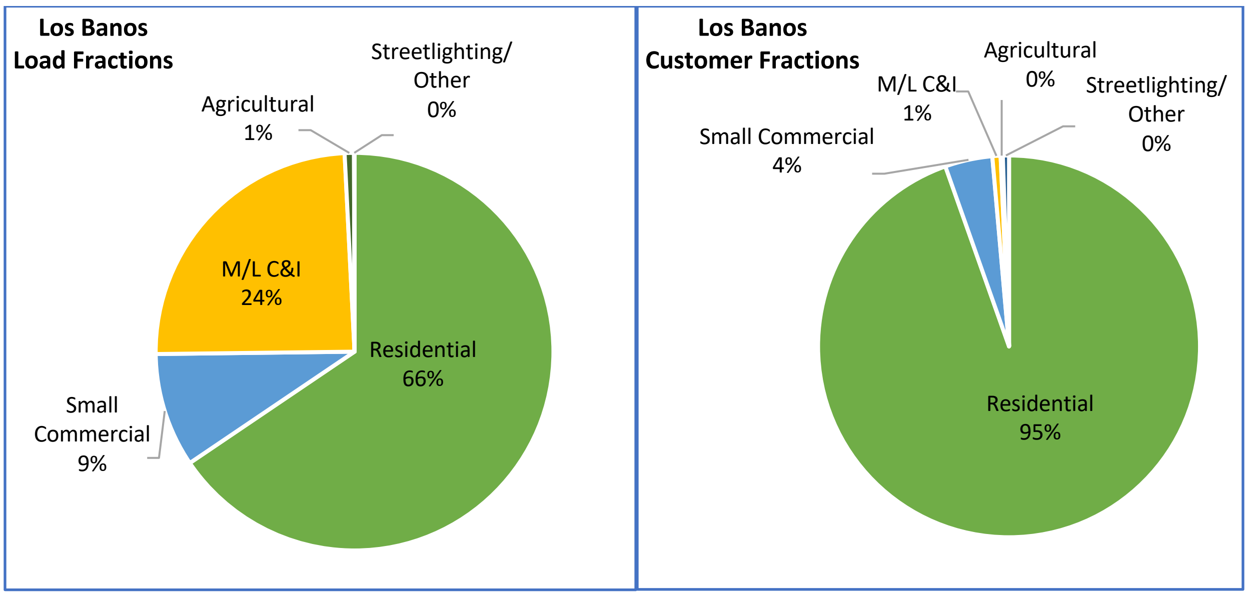
*Figures for 2021 are projections based on expected launches

[1] Figure courtesy of Cal-CCA.

Loads and Forecast

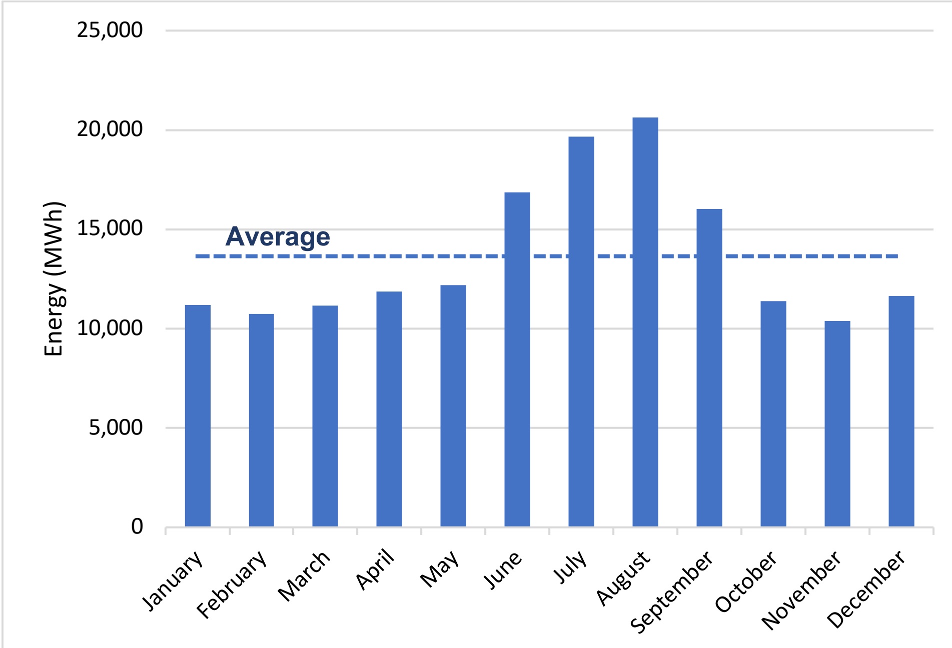
Based on PG&E's data and MRW's predictions, Los Banos will use over 170 GWh in 2020. Most of this consumption, about 66%, comes from residential customers. The remaining ~44% comes from medium and large commercial and industrial customers, with a few percent from small commercial, streetlighting and agriculture/pumping.

Figure ES-2. Los Banos Loads and Customer Breakdowns



Because Los Banos is in the hot Central Valley, its electrical loads are highest during the summer months, driven for the most part by air conditioning. Figure ES-3 shows Los Banos's monthly energy use. The usage in August is nearly 45% higher than the monthly average use and nearly double that of February, the lowest use month.

Figure ES-3. Los Banos Monthly Load (2020)



PCE's load is much larger than Los Banos's load; Los Banos would add about 5% to PCE's load (Table ES-1).[2] Both Los Banos and PCE customers have residential and small commercial as their largest customer segments. Although Los Banos experiences its highest loads in the summer (as opposed to PCE, whose highest loads are in the winter), and has a more variable load profile, PCE and Los Banos together will still have a winter peaking load, which is advantageous for purchasing energy.

Table ES-1: PCE and Los Banos Load and Customer Comparison

Customer Class	Annual Load, MWh		Number of Customers	
	PCE	Los Banos[2]	PCE	Los Banos[2]
Residential	1,488,186	107,311	266,835	13,996
Small Commercial	362,473	15,185	22,639	594
M/L C&I	1,363,818	39,939	3,995	103
Agricultural	24,522	1,235	239	28
Streeting/ Other	20,111	73	1,693	77
Total	3,259,110	163,742	295,401	14,797

[2] This assumes that 5% of Los Banos's load chooses to "opt out" and not be served by PCE.

Results

This study evaluates the costs and benefits of adding Los Banos to PCE by comparing PCE's total average cost to serve its customers (cents per kWh or dollar per MWh) to PG&E generation rates.

Figure ES-4 shows the forecast of PCE's average cost of service and PG&E's generation rates. The bars in the chart show the forecasts of the major cost components of CCA operation, while the single line shows the forecast of PG&E's retail generation rate. When the bars are below the line, PCE's average operating costs are lower than PG&E's generation rate, meaning that it can offer power to customers at a rate lower than PG&E. As the figure shows, but for the first year (2022), PCE's forecasted cost of service is below our forecast of PG&E's generation rate.

The bottom-most blue segment represents the cost of power to the CCA. This is the largest single cost and represent the cost to the CCA of all of its power purchases. The next segment up, orange, is the cost to acquire the capacity needed to comply with the state's resource adequacy (RA) program. That is, the cost that PCE must incur to demonstrate that it has enough generating capacity (in megawatts) to ensure that it can serve all its load, even if the "intermittent" renewable resources are not generating at their optimal rate (e.g., solar on rainy days). The more intermittent renewables—solar and wind—that are added to the CCA's generating mix, the more back-up capacity is needed to ensure reliability.

The next segment, gray, is for costs that PCE must pay to the grid operator.

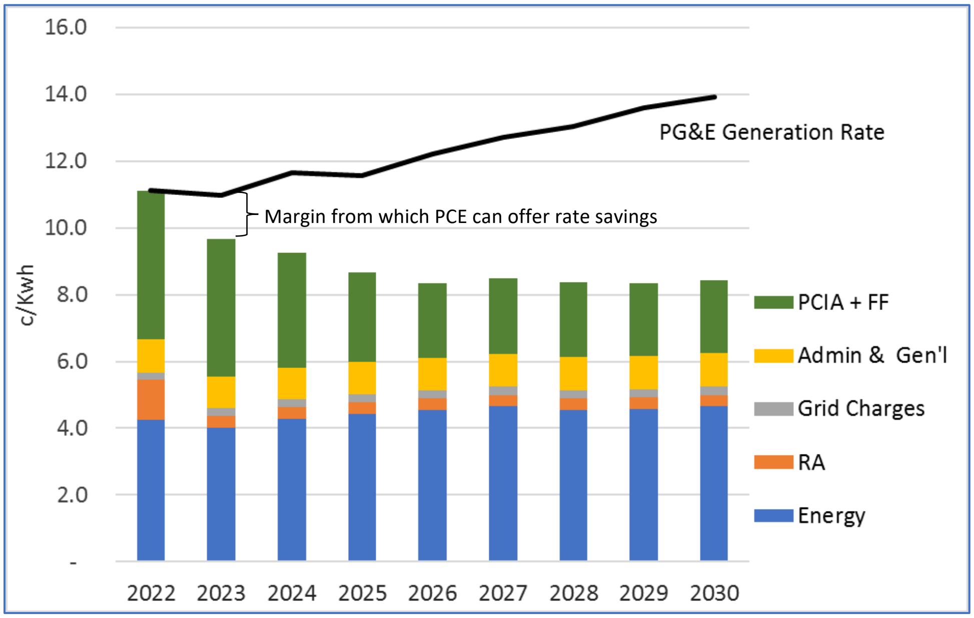
The next segment, yellow, is PCE's administrative and general costs. This includes all the costs PCE requires to operate (staff, rent, equipment, professional services) as well as the costs of PCE's community energy programs for its members.

The top-most green segment is for the Power Charge Indifference Adjustment (PCIA) and the Franchise Fee. The PCIA is a fee paid to PG&E to ensure that the operation of the CCA does not strand PG&E's remaining bundled customers with costs associated with power purchased on behalf of customers who have shifted to the CCA. The PCIA is not paid directly by the CCA, but by the individual customers taking CCA service. Thus, it does not appear explicitly on the CCA's books, however it must be accounted for in any CCA cost analysis. While both CCA customers and customers that choose to remain in PG&E bundled service pay this fee, it appears as a separate line item for CCA customers and is embedded in the energy generation costs of PG&E bundled customers.

Franchise fees are those collected by PG&E and paid to the City for the right to operate the electric monopoly franchise in the city. It is paid as a percent of each customer's total bill and is automatically built into PG&E's rates. The Franchise fee is very modest—less than 0.1¢/kWh.

The black line represents PG&E's average generation rate. The difference between the PG&E generation rates and the PCE cost plus PCIA columns is the amount that is available for rate discounts, contributions to cash reserves or funding additional programs. In 2022, because the sum of the costs approximately equals the PG&E generation rate, PCE will need to dip into its cash reserves to maintain its commitment to offer a 5% discount.

Figure ES-4. Forecast of PCE's Cost of Service (Without Los Banos) Versus PG&E's Generation Rate



Impact on PCE. MRW quantified the financial impact on PCE of adding Los Banos by comparing the changes in its cost of service and revenues. As shown in Table ES-2, over the nine-year study period, adding Los Banos increases PCE's costs by ~$111 million while increasing its revenues by ~$135 million. This results in a net benefit of about $24 million, or 1%. However, the impact is not equal in each year. In the earlier years, PCE incurs a net cost to serve Los Banos, with a break-even year of 2025.

Table ES-2. Change in PCE's Costs and Revenues from Adding Los Banos (millions $)

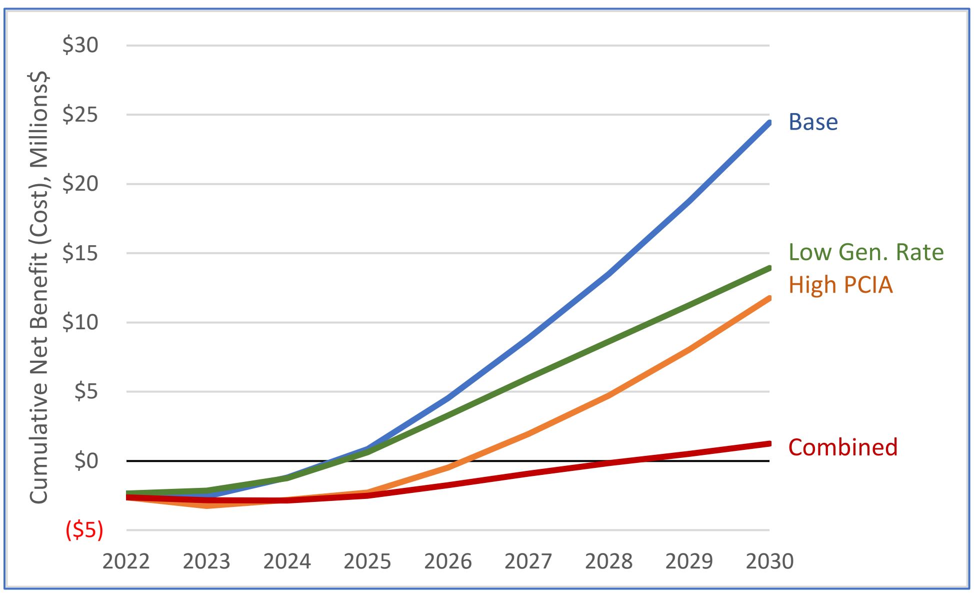
Year	Change in Costs	Change in Revenues	Net Benefit (Cost)	Net Benefit as % of Costs	Cumulative Net Benefit
2022	$13.0	$10.6	($2.4)	-1.1%	($2.4)
2023	$10.9	$10.7	($0.2)	-0.1%	($2.6)
2024	$11.5	$12.9	$1.4	0.7%	($1.2)
2025	$11.9	$14.0	$2.1	1.0%	$0.9
2026	$12.3	$15.9	$3.7	1.7%	$4.5
2027	$12.4	$16.7	$4.3	1.9%	$8.9
2028	$12.6	$17.3	$4.6	2.1%	$13.5
2029	$13.0	$18.3	$5.3	2.3%	$18.8
2030	$13.1	$18.7	$5.7	2.4%	$24.4
Total	$110.7	$135.1	$24.4	1.2%	**$24.4**

Alternative PG&E Rate Scenarios. The results shown above reflect expected market conditions and outcomes. However, it is unlikely that the conditions assumed in these Scenarios will occur exactly as assumed. In order to evaluate the robustness of the analysis, three additional cases were investigated: a higher PCIA forecast, a lower PG&E generation rate forecast, and a higher PCIA and lower generation rate forecast together. Raising the PCIA, lowering the PG&E generation rate, or both, lower the rate that PCE charges, as its rates are tied to PG&E's. Thus, in these sensitivities, the rate that PCE can charge is decreased while its costs remain the same.

Figure ES-5 shows the cumulative net financial benefit to PCE for the Base Case and the three sensitivity cases. Up until the line reaches zero, PCE is experiencing net costs by adding Los Banos. Once the line is above zero, then net benefits are accruing.

In the base case and all three sensitivity cases there is a net cost to PCE of adding Los Banos for the first few years. PCE's negative "investment" in Los Banos breaks even within the first five years (i.e., cumulative net benefits become positive) in all scenarios but the combined high PCIA/low generation rate sensitivity. For that case, the net benefits remain negative through 2028.

Figure ES-5. Fiscal Impact of Los Banos Joining PCE (sensitivity cases)



From Los Banos's point of view, as long as PCE is committed to keeping its customers' net generation rates at 5% less than PG&E's, the length of time it takes PCE to recoup the first years' costs is immaterial. Furthermore, given the very modest overall financial impact of adding Los Banos to PCE, MRW finds it unlikely that adding Los Banos would change PCE's rate setting policy.

From PCE's perspective, its Board must weigh the initial negative financial impacts, albeit modest, of adding Los Banos against the long-term benefits of the expansion.

Risks to Los Banos

While there are potential benefits to CCA formation, there are also risks. The major risks Los Banos should consider before committing to any CCA program are:

Financial Risk to City. Like all other CCA JPA agreements that MRW has seen, the PCE JPA agreement explicitly isolates its finances and liabilities from those of its members. In the event of a PCE failure or default, its member jurisdictions could not be held liable for the JPA's debts or obligations. Nor do any PCE JPA obligations appear on the City's books or impact its credit rating.

If PCE was having financial difficulties and had to charge rates that exceeded PG&E's, then the city, as a JPA member, might feel obligated to remain with PCE service at a higher cost rather than revert back PG&E. While this is possible and might occur in an isolated year, MRW believes that PCE can, over the long run, meet or beat PG&E's rates.

The primary financial risk to the Los Banos would be if it joined PCE but subsequently left after the JPA had entered into power contracts to serve the City's load. In that circumstance, the JPA agreement allows the JPA to impose fees to compensate it for any excess costs caused by the City's departure.

The City will not lose any revenue associated with franchise fees.[3] PG&E's Electric Rule 23, Section B.16 explicitly states that "CCA customers shall continue to be responsible to pay all applicable fees, surcharges and taxes as authorized by law. PG&E shall bill customers for franchise fees as set forth in Public Utilities Code Sections 6350 to 6354."

Rate and PCIA Uncertainty. A primary objective is to offer power to Los Banos residents and businesses at a competitive price relative to PG&E. In this circumstance, competitiveness is tied to the rates offered by PG&E. A number of factors can cause PCE's net power costs to exceed those of PG&E. PCE has in place risk management plans and options to both mitigate these risks by lowering rates passed on to customers back down to a competitive rate as well as to address unexpected risks. This includes a reserve fund that it can use to preserve, over a year or two, its 5% rate savings.

Direct Access and Competitive Retail Services. A possible important risk to PCE (and all CCAs) is the expansion of Direct Access (DA) eligibility.[4] The State currently limits the amount of load that may take this DA service. Currently, about 15% of the load in PG&E's territory is served through Direct Access, with an additional 3% in late 2020 due to the limited expansion of the DA program provided for in Senate Bill 237. In addition to modestly expanding the availability of DA service, SB 237 also directed the CPUC to report to the Legislature on how to

[3] Franchise fees are payments that a public utility makes to a city or county government for the nonexclusive right to install and maintain equipment on the government's right of ways. Franchise fees are generally calculated as a fraction of retail sales, typically on the order of a few percent.

[4] Direct Access (DA) service is retail electric service where non-residential customers purchase electricity from a competitive provider called an Electric Service Provider (ESP), instead of from a regulated electric utility or CCE provider.

open DA completely for all non-residential customers. The CPUC's report on how to fully open DA service is still pending, but the legislation's direction addresses mainly how to fully open DA service, not if it should. A fully opened DA market would allow any commercial or industrial customer served by PCE to switch its provider to a third-party, potentially reducing PCE's revenue and creating a mismatch between its wholesale power portfolio and its load. PCE management must follow this issue closely and take appropriate steps, such as altering its procurement mix and strategies, when the Legislature and CPUC act.

Energy Risk Management. Alls CCAs the financial risk of procuring energy, capacity, Renewable Energy Credits (RECs) and carbon-free energy (if needed) at a cost that exceeds the revenue that it receives from its retail customers. The other risks that are faced by a CCA roll up into the overarching risk of buying products and operating the CCA at a cost that exceeds revenue. To mitigate risk, a CCA must establish a sound risk management program that forms the structure for measuring, monitoring, and managing risk. PCE's Risk Management plan in can be found on their website.[5]

Legislative and Regulatory Risks Any CCA must meet various procurement requirements established by the State and implemented by the CPUC or other agencies. Regulatory risk, which changes the rules under which CCAs operate, affects the CCA's ability to maintain stable procurement activities, manage costs to its customers, and compete with the local incumbent utility and direct access providers.

Regulatory and legislative risk can only be managed though close monitoring of both relevant proceedings at the CPUC and legislation in Sacramento and intervening where needed to advocate for the CCA. The primary vehicle for regulatory intervention and legislative advocacy is to team up with other CCAs, such as through the state-wide CCA advocacy group, Cal-CCA.

Political Risk. Any major decision made by the city Council carries with it political risk. If the CCA goes well, it could go unnoticed by most residents and businesses. If things go upside down, the blame and accountability could be directed at the elected officials. Fortunately, to date, we have not seen this occur.

Governance and Implementation Options

If Los Banos decides to pursue CCA, it will have to decide between two primary governance options for the CCA: a city-only CCA or joining an existing JPA such as PCE.

In a city-only approach, Los Banos maintains full flexibility—and responsibility—for developing policies and procedures. This means that it can be tailored to and responsive to the City's stakeholders and constituents and based on the City's own specific objectives. Los Banos would be responsible for setting policy priorities in general and making specific decisions about power generation, staffing policies, local economic development activities and strategies, and the formulation of financial and debt policies. Along with greater autonomy, however, the City would assume all risk, liability, and costs associated with operating the CCA, including

[5] https://www.peninsulacleanenergy.com/wp-content/uploads/2017/01/Policy-7-Revised_Adopted-022317.pdf

$500,000-$1,000,000 of initial startup costs. In this case, the likely path would be for the City to establish the CCA as an enterprise fund, and work with appropriate legal counsel to explore options for controls and structural safeguards to insulate it and minimize risk to the City's general fund.

On the JPA side, Los Banos may become a member of PCE, the CCA that serves San Mateo County. PCE is governed by a board of directors with one voting member per each municipal jurisdiction and two directors representing San Mateo County. Except for extraordinary circumstances votes are tallied on an equal basis, one vote per director. If Los Banos were to join, it would be the 22nd municipal jurisdiction and have one out of 23 board members (Unincorporated San Mateo County has 2 voting board seats).

A JPA structure also reduces the risks of CCA participation by immunizing the financial assets of the City and the other member agencies participating in the CCA. The CCA's debts are its own, and creditors cannot come to the City for any recourse.

Los Banos should keep in mind that its priorities and objectives may differ from that of any JPA-organized CCA. This could manifest when setting priorities for local generation, economic development activities, and the importance of support programs. In the case of PCE, Los Banos should consider how PCE's priorities match its own. For example, PCE is committed to 100% renewable power by 2025; where it to pursue a less climate-aggressive goal, it might be able to offer lower rates.

Chapter 1. Introduction

What is a CCA?

California Assembly Bill 117, passed in 2002, established Community Choice Aggregation in California, for the purpose of providing the opportunity for local governments or special jurisdictions to procure and provide electric power for their residents and businesses.

Under existing rules administered by the California Public Utilities Commission, an investor-owned utility (IOU) must use its transmission and distribution system to deliver the electricity supplied by a CCA in a non-discriminatory manner. That is, it must provide these delivery services at the same price and at the same level of reliability to customers taking their power from a CCA as it does for its own full-service customers. By state law, an IOU also must provide all metering and billing services, its customers receiving a single electric bill each month from the IOU, which would differentiate the charges for generation services provided by the CCA as well as charges for IOU delivery services. Money collected by the IOU on behalf of the CCA is remitted in a timely fashion (e.g., within 3 business days).

As a power provider, the CCA must abide by the rules and regulations placed on it by the state and its regulating agencies, such as maintaining demonstrably reliable supplies and fully cooperating with the State's power grid operator. However, the State has no rate-setting authority over the CCA; the CCA CCA's governing board has the authority to set rates as it sees fit so as to best serve its constituent customers.

Per California law, when a CCA is formed all residential electric customers within its boundaries will be placed, by default, onto CCA service. (the CCA may elect to serve non-residential customers but is only obligated by law to do so). However, customers retain the right to return to PG&E service at will, subject to whatever administrative fees the CCA may choose to impose—typically $5 for a residential customer and $25 for a non-residential customer.

Understanding CCA's Objectives

The feasibility of a CCA program is a function of that program's ability to meet the sponsoring City's or JPA's goals and objectives. This section lays out the typical CCA goals and objectives, how they might apply to Los Banos, and how they overlap with PCE's goals.

Rate Competitiveness and Financial Stability

By joining PCE or forming its own CCA, Los Banos would expect to experience rates that are competitive with those offered by the incumbent electric utility, Pacific Gas & Electric (PG&E). "Competitive" here means that the CCA, over the long run, could offer rates that are equal to or less than those offered by PG&E. It does not mean that in each and every year a specific rate savings is offered. In fact, some CCAs rates are slightly higher than their host utility. PCE, on the other hand, has offered its customers a 5% discount off their PG&E generation rate since its inception. This transplants into a bill savings of around 2½%. PCE's Board has the authority to set rates as it sees fit to manage the overall business and financial health of the CCA. While PCE cannot guarantee a rate savings relative to PG&E, MRW's review of its power portfolio and ongoing budget plans suggests that it should be able to do so.

Contribute to Climate Action Objectives

Many cities in California are making explicit goals of reducing their carbon emissions. Forming or joining a CCA is one common way that these cities can reduce their carbon footprints. This is because the CCA can procure their power from more renewable and non-emitting energy sources than their incumbent utility.

It must be noted that California is also moving towards a similar carbon-free electricity policy. Senate Bill 100, which was signed into law by Governor Brown on September 17, 2018, increases the renewable power content requirement of all retail power providers, including utilities and CCAs, from 50% to 60% by 2030. The bill also says "that it is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers by December 31, 2045," and that all state agencies regulating electricity build this goal into their planning. This effectively means that the difference between the electricity carbon content of a CCA and PG&E service may not be significant.

PCE has made climate protection a cornerstone policy. PCE aims to be 100% greenhouse gas free by 2021 and by 2025, it plans to deliver 100% renewable energy 24/7.[6] They currently offer at least 50% renewable, 95% carbon-free energy to all their customers according to the California renewable portfolio definitions. They also offer a 100% renewable "opt-up" option to their customers.

Additional Objectives

While maintaining rate competitiveness and financial stability are likely non-negotiable objectives, a CCA can also serve as a vehicle to pursue other objectives that benefit Los Banos, its residents, and businesses. Examples of additional objectives could include the following.

Local energy programs. Many CCAs are prioritizing programs they can provide to benefit their constituents. PCE currently spends about 25% of their non-power-related operating budget on community programs. For example, PCE has a $6.1 million program to help decarbonize existing buildings through clean appliance incentives, building upgrades, and workforce development.[7] It is investing $10 million in resiliency programs to provide clean backup power for medically vulnerable residents and essential community services during grid outages and other natural disasters. PCE also is providing rebates for free or low-cost battery back-up power.[8] Additionally, in 2020, to address the impacts of COVID-19, they provided an additional $3.6 million in bill credits to low-income customers.[9]

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[6] https://www.peninsulacleanenergy.com/background/
[7] PCE Strategic Plan 2020-2025, p. 4
[8] https://www.peninsulacleanenergy.com/pop/
[9] PCE Strategic Plan 2020-2025, p. 4

PCE is also supports electric vehicles (EVs). Through their EV incentive programs, they have provided over $500,000 in vehicle rebates as of May 2020.[10] They also committed $16 million for EV charging infrastructure.[11] PCE plans to install 3,500 EV charging ports between 2021 and 2024.[12] PCE is also supporting pilots for an EV charging application program and an awareness program with Lyft.

Economic development. A CCA can potentially contribute to local economic development in two ways. First, if the CCA offers reduced electricity rates, additional dollars can flow into the local economy as households and businesses spend their incomes on items and services other than electricity. Second, the CCA can offer programs that allow households and businesses to reduce the power consumption, such as energy efficiency and distributed energy resources.

Local jobs and employment. Beyond the potential jobs that could result from the economic stimulus of possibly lower rates, the CCA can more directly incentivize and support local job creation. This includes employing residents in CCA administration and using local contractors for energy efficiency programs and distributed energy generation (e.g., rooftop solar installers and maintainers). The CCA can also partner with local community colleges and/or trades apprenticeship programs to support quality local job opportunities.

Prioritization of renewable power development. Beyond support of locally sited distributed energy generation ("DEG," e.g., rooftop solar), a CCA may prioritize siting larger, grid-connected DEG and utility-scale renewable project locally.

Figure 1. Wright Solar Park

An example of a jobs-creating renewable power project is PCE's Wright Solar Park. The solar park can produce 200 MW and is providing 400 union jobs.[13]

Local citizen input and participation. A primary purpose of a CCA is to better reflect its community's interests and values than an investor-owned utility like PG&E can. A CCA may commit to providing opportunities for citizens to contribute input into its programs and policies, such as having a citizens' advisory board or having a non-voting at-large community seat on the CCA's board of directors.

[10] PCE Strategic Plan 2020-2025, p. 4
[11] PCE Strategic Plan 2020-2025, p. 5
[12] PCE Strategic Plan 2020-2025, p. 4
[13] Community Impact Report, p. 7

Assessing CCA Feasibility

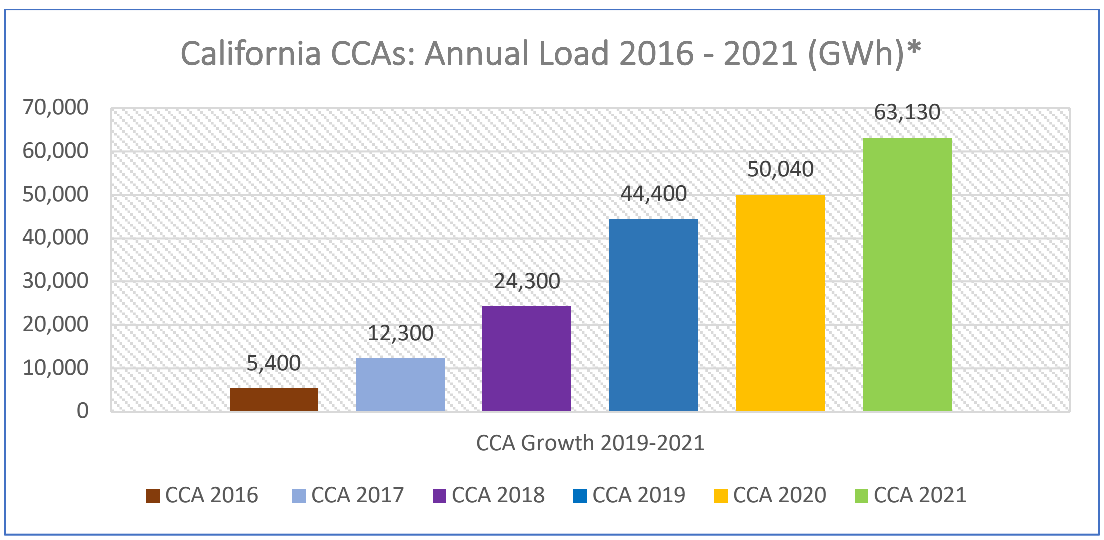
In order to assess whether adding Los Banos to PCE is "feasible" for Los Banos, the local objectives must be laid out and understood. Based on the specifications provided, this study:

- Quantifies the electric loads that a Los Banos CCA would have to serve.
- Estimates the start-up costs to add Los Banos to PCE.
- Compares the rates that could be offered by PCE to Los Banos to PG&E's rates.
- Quantitatively explores the financial impact to PCE of adding Los Banos.
- Discuses, and where possible, quantifies the risks to the City and its residents and businesses of CCA formation.

Status of CCAs in California

Even though the enabling legislation was enacted in 2002, the first CCA to provide power, Marin Clean Energy (MCE), did not enroll customers until 2010. For the next five years, others investigated CCA formation, with a few early adopters stepping up in 2014 through 2016. As shown in Figure 2, once these early adopters showed that CCAs could work, the flood gates opened in 2017. By the end of 2021, CCAs are expected to serve over 63,000 GWhs, with some projecting that by the mid-2020s, between 50 to 80 percent of the load in the three main IOU service territories will be served by non-utility entities (CCAs and Direct Access providers).

Figure 2. California CCA Load Growth[14]



*Figures for 2020/2021 are projections based on expected launches

Table 1 lists the active CCAs in California, including those which have announced intended launches in 2020 and 2021, along with their location and governance structure. As the table shows, most of the current CCAs are in PG&E's service area, but the growth in 2020 will come from new CCAs in SCE's territory. Currently there is only one small CCA in SDG&E's

[14] Figure courtesy of Cal-CCA.

territory, Solana Energy Alliance, but a large JPA in the San Diego region is intending to begin service in 2021.

The table also shows that the majority of CCAs are organized as joint powers authorities (JPAs). There are also many smaller cities in Southern California Edison's service area that use the "JPA Light" model, in which the CCA is technically a city enterprise that relies upon the California Choice Energy Authority (CCEA) to provide the technical operations. There are also four stand-alone city CCA enterprises: San Francisco, San Jose, Solana Beach, and King City. The latter two would be similar to the size of a stand-alone Los Banos CCA.

Table 1. CCAs in California

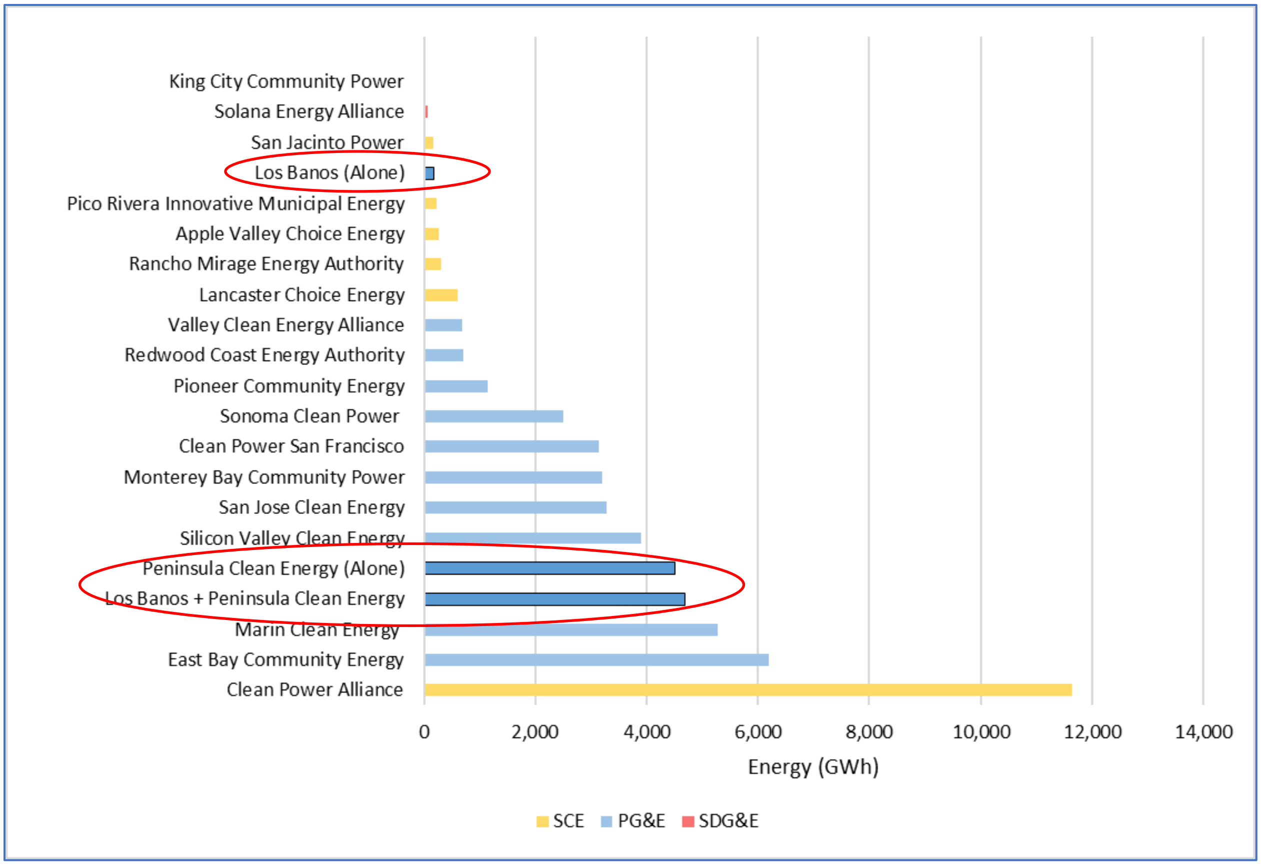
CCA	IOU	Type	Formed	Load, GWh[15]
CCEs delivering power in California				
Clean Power San Francisco	PG&E	City	May 2016	3,135
East Bay Community Energy	PG&E	JPA	Jan.2018	6,200
King City Community Power	PG&E	City	July 2018	35
Marin Clean Energy	PG&E	JPA	May 2010	5,275
Monterey Bay Community Power	PG&E	JPA	March 2018	3,202
Peninsula Clean Energy	PG&E	JPA	Oct. 2016	3,600
Pioneer Community Energy	PG&E	JPA	2018	NA
Redwood Coast Energy Authority	PG&E	JPA	May 2017	699
San Jose Clean Energy	PG&E	City	Sept. 2018	3,286
Silicon Valley Clean Energy	PG&E	JPA	April 2017	3,898
Sonoma Clean Power	PG&E	JPA	May 2014	2,502
Valley Clean Energy Alliance	PG&E	JPA	Dec. 2016	682
Clean Power Alliance	SCE	JPA	Feb. 2018	10,295
Apple Valley Choice Energy	SCE	City; CCEA[16]	April 2017	260
Lancaster Choice Energy	SCE	City; CCEA	May 2015	600
Pico Rivera Innovative Muni'l Energy	SCE	City; CCEA	Sept. 2017	220
Rancho Mirage Energy Authority	SCE	City; CCEA	May 2018	300
San Jacinto Power	SCE	City; CCEA	April 2018	170
Desert Community Energy	SCE	JPA	April 2020	1,668
Western Community Energy	SCE	JPA	2020	1,575
Solana Energy Alliance	SDG&E	City	June 2018	37
Planned Launch				
Baldwin Park	SCE	City; CCEA	2020	255

[15] 2019 Load (GWh) reported by CalCCA: https://cal-cca.org/cca-impact/
[16] CCEA = CalChoice Energy Authority, the JPA-Light serving small communities in SCE's territory.

CCA	IOU	Type	Formed	Load, GWh[15]
Pomona	SCE	City; CCEA	2020	655
Palmdale (on hold)	SCE	City; CCEA	TBD	655
Hanford (on hold)	SCE	City; CCEA	TBD	285
Commerce	SCE	City; CCEA	2021	460
San Diego Regional CCA Authority	SDG&E	JPA	2021	6,800
Butte County (on hold)	PG&E	JPA	TBD	1,080
Expansions of Existing CCEs				
Westlake Village	SCE	JPA (CPA)	2020	
Santa Barbara (City)	SCE	City (CCEA)	2021	
Del Rey Oaks	PG&E	JPA (MBCP)	2021	
Arroyo Grande	PG&E	JPA (MBCP)	2021	
Grover Beach	PG&E	JPA (MBCP)	2021	
Paso Robles	PG&E	JPA (MBCP)	2021	
Pismo Beach	PG&E	JPA (MBCP)	2021	
Carpinteria	SCE	JPA (MBCP)	2021	
Goleta	SCE	JPA (MBCP)	2021	
Guadalupe	PG&E	JPA (MBCP)	2021	
Santa Maria	PG&E	JPA (MBCP)	2021	
County of Santa Barbara	PG&E, SCE	JPA (MBCP)	2021	
San Luis Obispo (City)	PG&E	JPA (MBCP)	2021	
Morro Bay	PG&E	JPA (MBCP)	2021	
Drafted ordinances for implementation as soon as 2022				
North San Diego County CCA	SDG&E	JPA	2022	2,750

Figure 3 shows the 2019 annual loads of the operating CCAs in California. The figure shows that were Los Banos to pursue a stand-alone CCA, it would be one of the smallest in the California, with only 3 CCAs that are smaller. Adding Los Banos to PCE would modestly increase PCE's load, but not change its overall rank of the 4th largest CCA in the state.

Figure 3. California CCA Load by Utility (2019)



CCA Evolution

Over the first years of operation, many California CCAs have evolved from a simple commodity procurement entity—providing power, albeit greener, at a competitive rate. After a few years, many CCAs have expanded into providing targeted and specialized customer programs that while customized for their communities, are variations of services provided by their host IOU or are generally proven in the industry. Examples of this include CCAs like MCE, which has exercised its right to apply for energy efficiency (EE) program funding from the CPUC.[17] To do so, it must file various plans explicitly detailing what they intend to do in the EE program along with reporting requirements and protocols to verify that the energy savings that is projected will occur. If approved, then the CCA will receive money that is collected in IOU rates through the Public Purpose Program rate element. Another example of this second phase of CCA evolution is offering rooftop solar programs and feed-in-tariffs for local renewable generation projects that

[17] Note that customers taking commodity service from a CCA are still eligible to participate in EE programs administered by their host IOU, regardless of whether or not the CCA is administering their own PPP-funded EE programs or not.

connect "in front of" the customer meter. A third example is installing additional EV charging stations and encouraging EV purchasing and leasing.

The third phase in evolution observed with California CCAs is moving into innovative and less common power-related programs and services. These are programs that are not common in California or elsewhere and may be more in the "demonstration" part of the program/technology lifecycle. Examples of these programs include Sonoma Clean Power's efforts to electrify the areas that were destroyed in wildfires (i.e., work with PG&E to perhaps not provide gas service to these areas) or the microgrid programs being pursued by Redwood Coast Energy Authority and Monterey Bay Community Power.

Table 2 shows a range of the programs being pursued by some California CCAs.
These non-commodity program offerings are becoming the focus of CCAs in the state. At the Business of Local Energy Symposium, a large CCA-oriented conference held in June 2019 in Irvine, the speakers, panels and presentations overwhelmingly focused on innovation that CCAs can do and are doing.[18] None addressed power procurement or cost competitiveness.

[18] https://theclimatecenter.org/the-business-of-local-energy-symposium-2019-presentations/

Table 2. Sample CCA Programs *(source: CalCCA)*

	Apple Valley Choice Energy	CleanPowerSF	Clean Power Alliance	East Bay Community Energy	King City Community Power	Lancaster Choice Energy	MCE	Monterey Bay Community Power	Peninsula Clean Energy	Pioneer	PRIME	Rancho Mirage Energy Authority	Redwood Coast Energy Authority	San Jacinto Power	San Jose Clean Energy	Silicon Valley Clean Energy	Solana Energy Alliance	Sonoma Clean Power	Valley Clean Energy
Budget Billing		*In dev.*				✔													
Battery Storage Rate		*In dev.*		✔ *(pilot)*			✔									✔ (Same as PG&E)		*In dev.*	
Demand Response		✔	✔				*In dev.*	✔	*In dev.*							*In dev.*		✔	✔
EV Rate		✔	✔	✔ (Same as PG&E)		✔	✔	✔	✔		✔		✔		✔ (Same as PG&E)	✔ (Same as PG&E)	✔	✔	✔ (Same as PG&E)
EV Bus Program		✔				✔			✔									✔	
EV Incentives (vehicles and/or charging)						✔	✔	✔	✔				✔		*In dev.*	✔		✔	*In dev.*
EV Load Shifting			✔				✔									✔ *(pilot)*		✔	
Energy Efficiency						✔	✔				*In dev.*		✔			*In dev.*		✔	*In dev.*
Energy Efficiency Data Sharing				✔															
Low-Income & Multifamily EE							✔		*In dev.*		✔		✔						
Feed-In Tariff		*In dev.*					✔	*In dev.*					✔					✔	
Fuel Switching (Electrification)				*In dev.*			✔	*In dev.*	*In dev.*				✔			✔		✔	*In dev.*
Solar Incentives												✔	✔						
Low-Income Solar Incentives		✔	*In dev.*	✔			✔	✔	*In dev.*		✔								

CALCCA ADVANCING LOCAL ENERGY CHOICE	Apple Valley Choice Energy	CleanPowerSF	Clean Power Alliance	East Bay Community Energy	King City Community Power	Lancaster Choice Energy	MCE	Monterey Bay Community Power	Peninsula Clean Energy	Pioneer	PRIME	Rancho Mirage Energy Authority	Redwood Coast Energy Authority	San Jacinto Power	San Jose Clean Energy	Silicon Valley Clean Energy	Solana Energy Alliance	Sonoma Clean Power	Valley Clean Energy
On-Bill Repayment		*In dev.*					✓											*In dev.*	
Education, Outreach, and/or Innovation Grants			✓	✓					✓	*In dev.*						✓		✓	
Customer Load Shifting		✓					✓									*In dev.*		✓	
Microgrid Development						✓		✓					✓						
Citizen Sourcing			✓			✓							✓						
Energy Education in Local Schools		*In dev.*							✓						✓			✓	
Dividend Program								✓											✓
Solar Referral Service			✓																
Solar+Storage on Critical Facilities			*In dev.*	✓			✓		✓				✓			✓		✓	
Advancing Reach Codes				✓					✓							✓		✓	
Advanced Energy Rebuild							✓											✓	
TOU Rates		✓		✓ (Same as PG&E)		✓	✓						✓		✓ (Same as PG&E)	✓ (Same as PG&E)	✓	✓ (Same as PG&E)	✓ (Same as PG&E)
Customer C&I Clean Power Offerings																✓			
Emissions Inventory Support for Member Agencies								✓								✓			

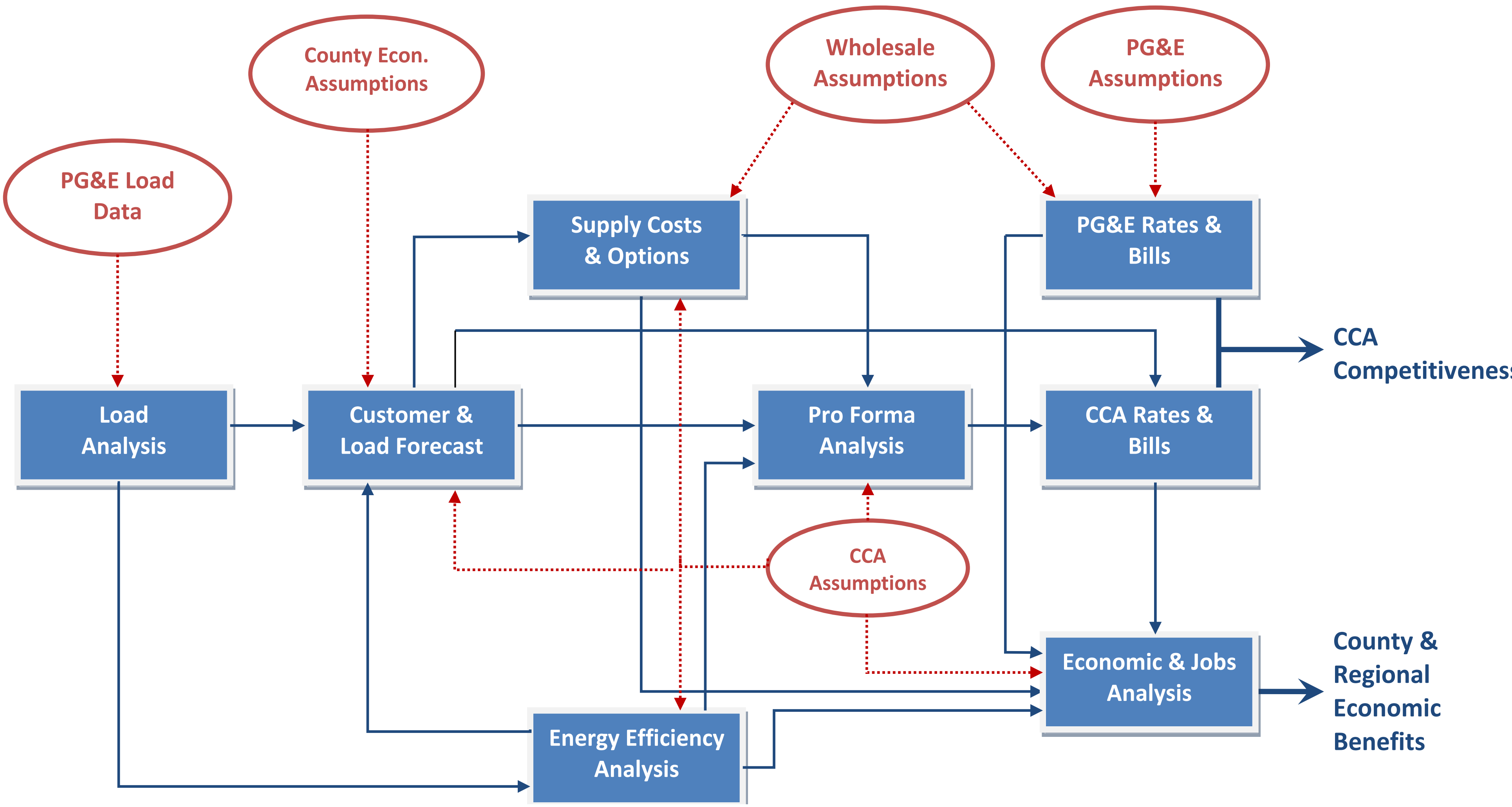
Chapter 2. Economic Study Methodology and Key Inputs

This chapter summarizes the key inputs and methodologies used to evaluate the cost-effectiveness to PCE of adding Los Banos, relative to PG&E.

Understanding the interrelationships of all the tasks and using consistent and coherent assumptions throughout are critical to developing a meaningful analysis. Figure 4 shows the analysis elements (blue boxes) and major assumptions (red ovals) and how they relate to each other. As the figure illustrates, there are numerous interrelationships between the tasks.

An important point is highlighted in this figure, it is critical that wholesale power market assumptions are consistent between the CCA and PG&E. While there are reasons that one might have lower or higher costs than the other for a particular product (e.g., CCAs can use tax-free debt to finance generation projects while PG&E cannot), both will participate in the wider Western U.S. gas and power markets and therefore will be subject to the same underlying market forces. Applying different power cost assumptions to the CCA than to PG&E, such as simply escalating PG&E rates while deriving the CCA rates using a bottom-up approach, would produce erroneous results.

Figure 4. General CCA Analysis



Los Banos and PCE Loads and Load Forecasts

Los Banos Load

Table 3: 2020 Los Banos Load Summary

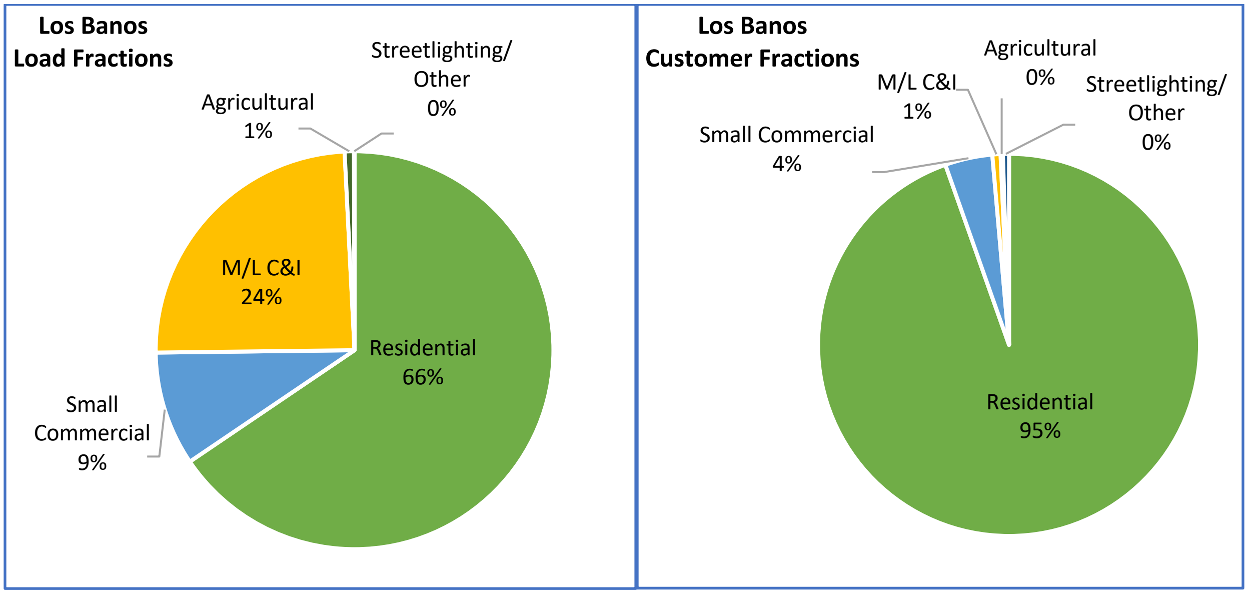
Customer Class	Number of Customers	Annual Load (MWh)
Residential	14,733	112,959
Small Commercial	625	15,984
Medium and Large Commercial & Industrial	108	42,041
Agricultural	29	1,300
Streetlighting/ Other	81	77
Total	15,576	172,360

and **Error! Reference source not found.** summarize Los Banos's load. As the table and figure show, residential usage accounts for a majority of the city's load (66%) and a vast majority of the customers (95%). Medium and large commercial/industrial customers make up about 24% of the load and 1% of the customers, while small commercial, streetlighting, agriculture and pumping loads make up the rest. This profile differs significantly from PG&E as whole, which on a load basis is roughly 1/3 residential and 2/3 commercial and industrial.

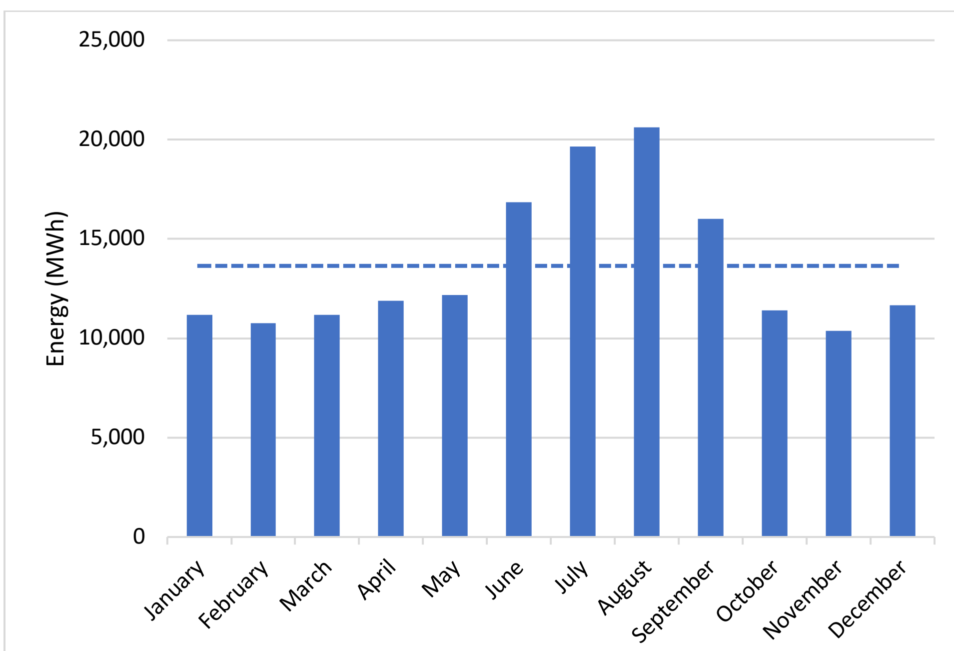
Table 3: 2020 Los Banos Load Summary

Customer Class	Number of Customers	Annual Load (MWh)
Residential	14,733	112,959
Small Commercial	625	15,984
Medium and Large Commercial & Industrial	108	42,041
Agricultural	29	1,300
Streetlighting/ Other	81	77
Total	15,576	172,360

Figure 5. 2020 Los Banos Loads and Customer Breakdowns



Because Los Banos is in the hot Central Valley, its electrical loads are highest during the summer months, driven for the most part by air conditioning. Figure 6. Los Banos Monthly Load (2020)



shows Los Banos's monthly energy use. The usage in August is nearly 45% higher than the monthly average use and nearly double that of February, the lowest usage month.

Figure 6. Los Banos Monthly Load (2020)

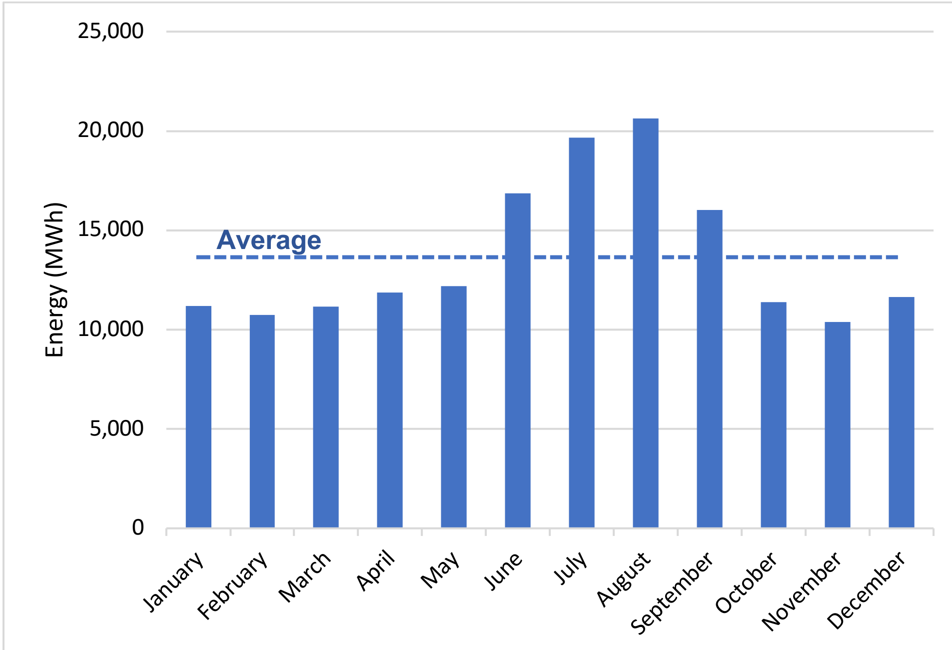
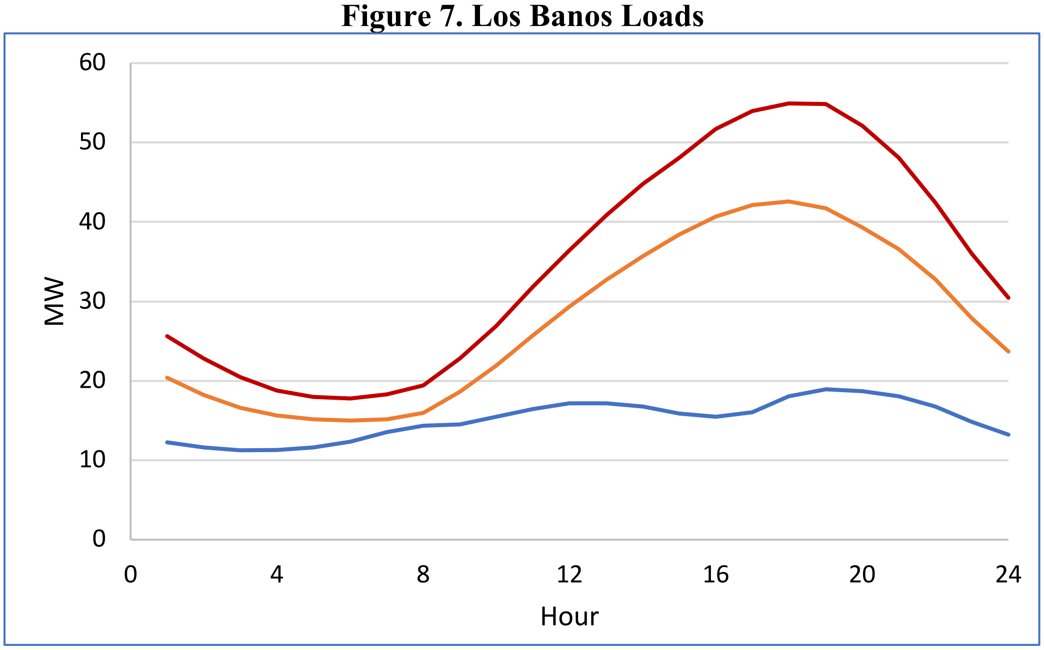


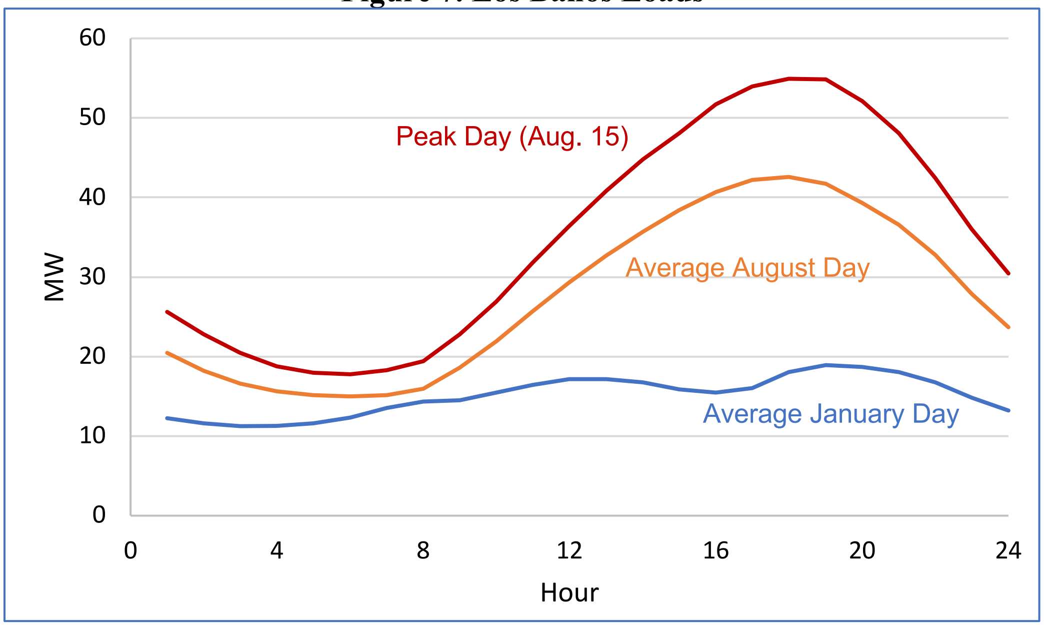
Figure 7. Los Banos Loads



shows Los Banos's estimated hourly 2020 usage for three different times: the average hourly use in January, the hourly average use in August, and the day with the highest use in all of 2020, August 15. During the winter months like January, Los Banos's load is relatively flat with very shallow peaks around noon and 6:00 pm. In the summer, the load fluctuates widely. On a typical August day, the load varies from below 20 MW to above 40 MW with peak hours being from 5:00 to 8:00 pm. On its highest peak day, Los Banos's load reached 55 MW at 6 pm.

This usage profile with much higher demands in the summer has implications for a CCA serving the City's load. Wholesale power costs in the late summer afternoons and evenings—when Los Banos has its highest loads—tend to be the highest. In addition, a CCA serving the city would also have to ensure that it is has enough generation resources on contract to meet the peak load (55 MW). This, too, can be costly. (See the section Capacity Costs for more detail on how CCAs must meet their peak day obligations.)

Figure 7. Los Banos Loads



Los Banos In Context With PCE

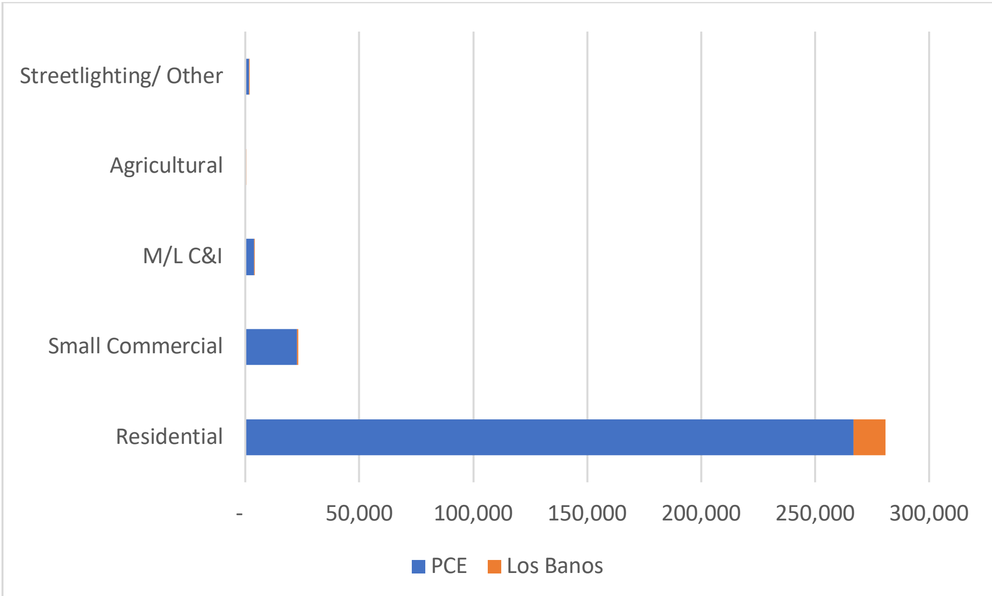
As noted earlier, PCE's load is much larger than Los Banos's load; Los Banos on average adds an extra 5% to PCE's load.[19] (See Table 4: 2020 PCE and Los Banos Load and Customer Comparison

Customer Class	Annual Load, MWh		Number of Customers	
	PCE	Los Banos[19]	PCE	Los Banos[19]
Residential	1,488,186	107,311	266,835	13,996
Small Commercial	362,473	15,185	22,639	594
Med. & Large C&I	1,363,818	39,939	3,995	103
Agricultural	24,522	1,235	239	28
Streetlighting/ Other	20,111	73	1,693	77

[19] This assumes that 5% of Los Banos's load chooses to "opt out" and not be served by PCE.

Total	3,259,110	163,742	295,401	14,797

and Figure 8. 2020 Annual Load for Los Banos and PCE



.) Both Los Banos and PCE customers have residential and medium commercial as their largest segments. Again, PCE is much larger than Los Banos. With respect to accounts, including Los Banos would add 5%, or about 15,000 more customers to PCE.

Table 4: 2020 PCE and Los Banos Load and Customer Comparison

Customer Class	Annual Load, MWh		Number of Customers	
	PCE	Los Banos[19]	PCE	Los Banos[19]
Residential	1,488,186	107,311	266,835	13,996
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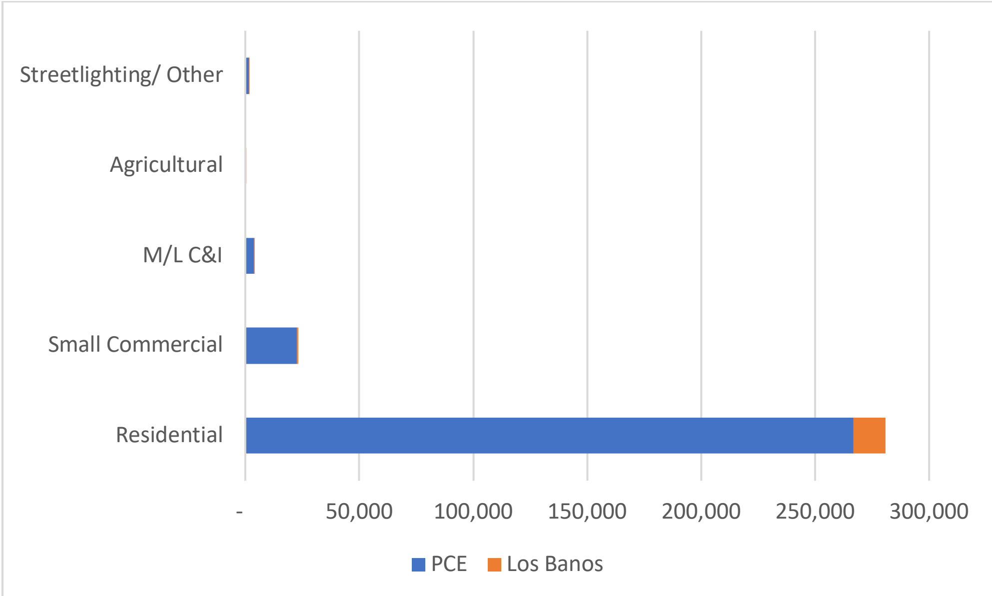


Compared to Los Banos, PCE's load profiles are less variable. During the winter, PCE uses 16% more energy than it does in the summer. This is the opposite of Los Banos, which uses more energy in the summer. PCE has a winter peaking load because of the very modest air conditioning load in San Mateo county (reducing summer loads) coupled with higher lighting and electric heating in the winter.

As PCE is so much bigger than Los Banos, its load profile would not change much with the addition of Los Banos. As shown in Figure 9. 2020 Monthly Energy for Los Banos and PCE

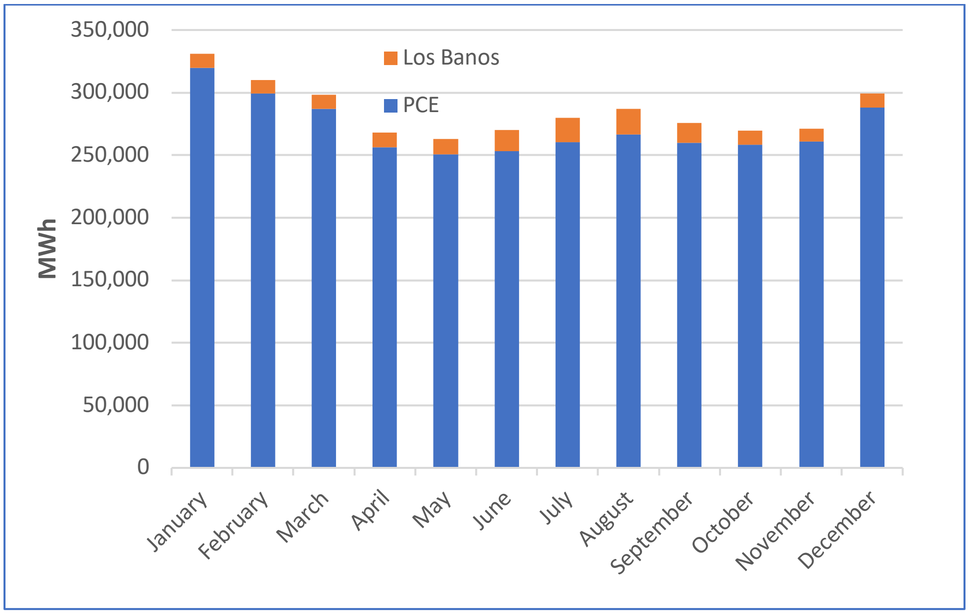
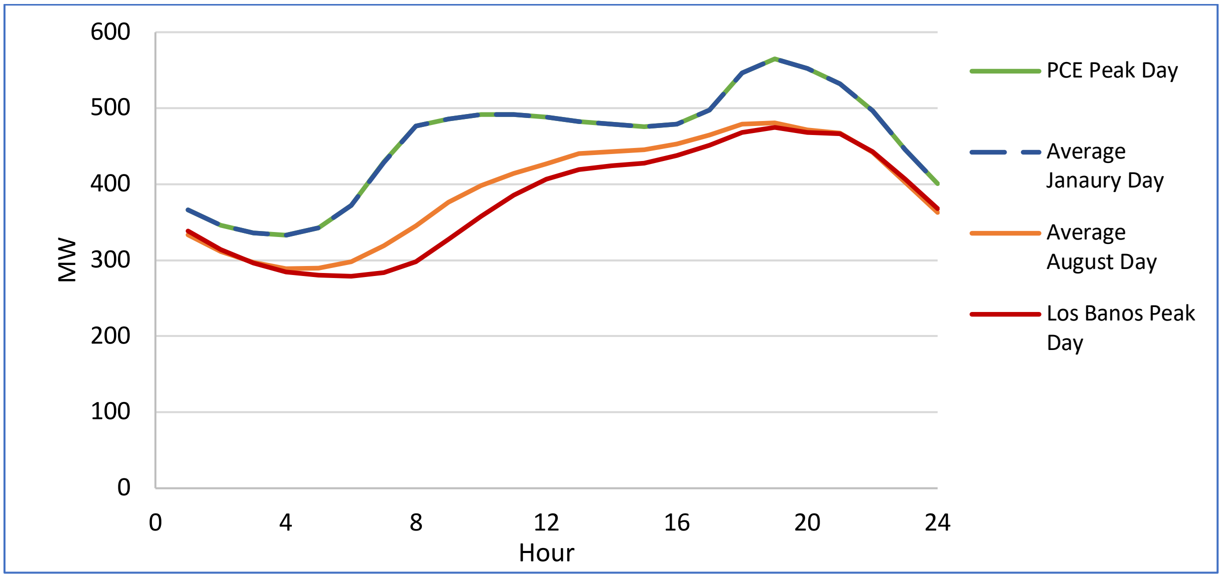


Figure 10 shows the daily profile for the combined Los Banos and PCE load in 2020. Similar to Figure 7, the figure shows the average hourly use in January, the hourly average use in August, and the day with Los Banos highest use in all of 2020, August 15. In addition to those profiles, it also has the day with PCE's highest usage, January 1. Although Los Banos peaks in the summer and has a more variable load profile, adding in Los Banos does not materially impact PCE.

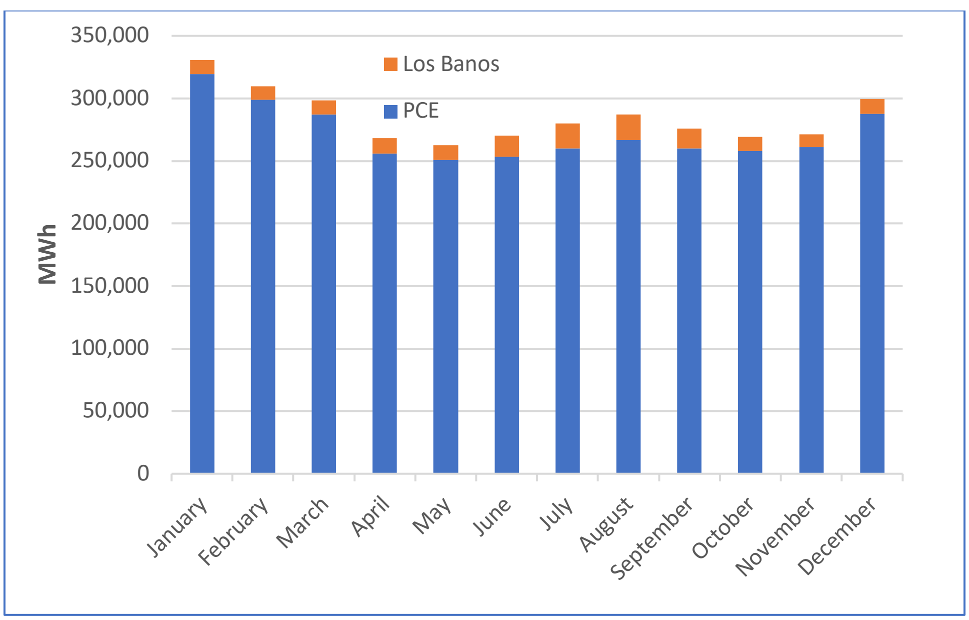
Instead, the addition of PCE to Los Banos makes the summer load shape much flatter compared to Figure 7 and the peak season for the combined loads is in the winter.

Figure 10. Combined Los Banos and PCE Loads (2020)



, the most notable, albeit still small, change is in the summer months when Los Banos's usage is highest. However, even with the additional summer load from Los Banos, the combination of PCE and Los Banos still uses the most energy during the winter.

Figure 9. 2020 Monthly Energy for Los Banos and PCE



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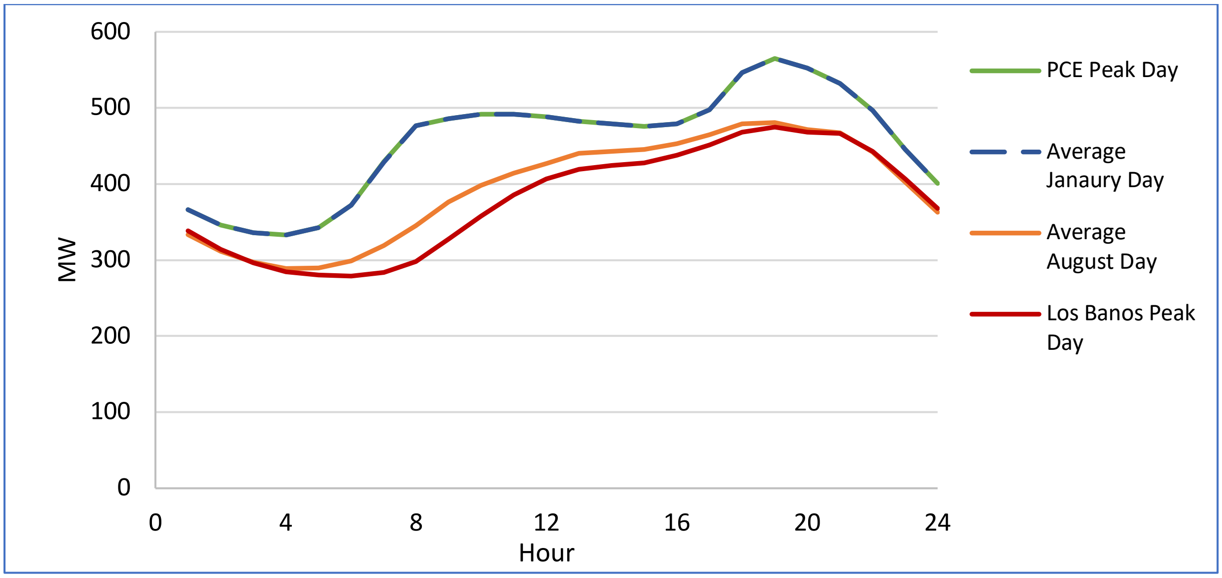
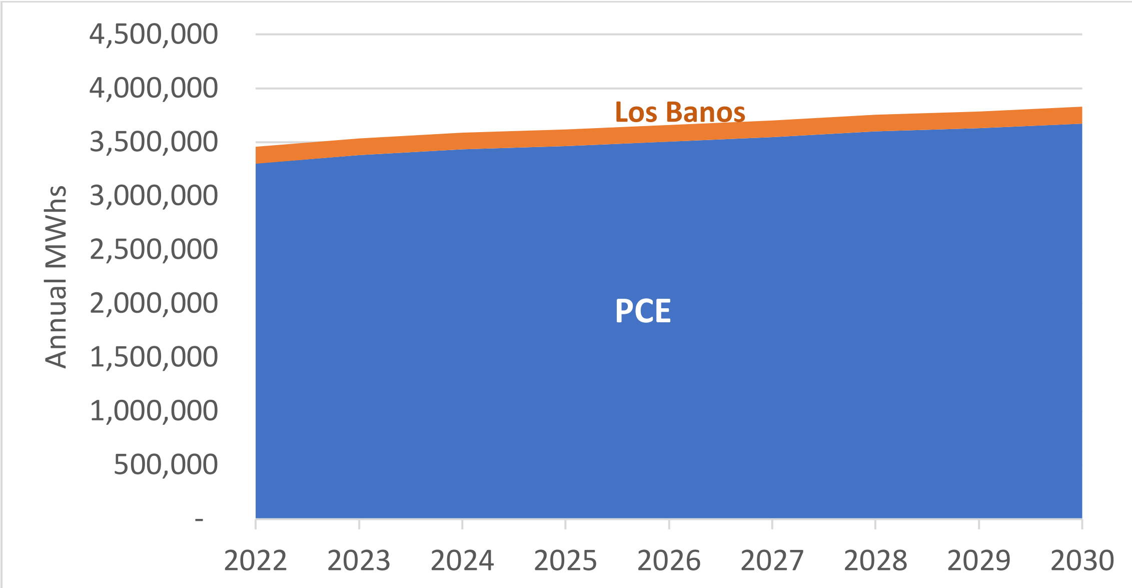


Combining the two loads is beneficial for both PCE and Los Banos. PCE can simply incorporate the extra load and operate business-as-usual as Los Banos will not affect the types of resources PCE will need to purchase. Los Banos will be able to use its energy resources more efficiently because of PCE's more even energy usage and load profile. Furthermore, PCE and Los Banos together will still have a winter peaking load which is advantageous for purchasing energy.

PCE and Los Banos Load Forecasts

The loads discussed so far are from 2020 using PCE's internal load forecast, PG&E data and MRW's own assumptions. For 2022 and beyond, MRW continued to rely upon PCE's internal load forecast and assumed that Los Banos's load would increase at the same rate as PCE's. This is shown in Figure 11.

Figure 11. Load Forecast (MWh)



Note that PCE's load forecast accounts for estimated impacts of COVID-19. PCE and other LSEs have found that the load associated with commercial and industrial accounts have dropped significantly, while residential loads have modestly increased. PCE assumed that its loads would return to their current levels by 2023. Given that this study begins in 2022, COVID-19 does not have a material impact.

PCE Power Supplies

Regulatory Procurement Requirements

California places a number of important power-procurement requirements on all "load serving entities" (LSEs) in California (e.g., utilities like PG&E and CCAs). These requirements apply to all LSEs and thus can limit the options that a CCA can pursue to lower costs or implement lower-GHG emitting power portfolios.

Renewable Power. One of these requirements is the renewable portfolio standard (RPS). This requirement has been in place since 2002 with passage of Senate Bill (SB) 1078, which set a requirement that 20% of retail electricity sales be served by renewable resources by 2017. Since then, the RPS requirement has been accelerated and expanded by subsequent legislation, most recently by SB 100 passed in 2018. SB 100 requires all LSEs to procure 50% of their power from renewable resources by 2026 and 60% by 2030.[20] SB 100 also sets a state-wide policy goal of having 100% of the electric power met by renewable or carbon-free resources (e.g., including large hydroelectric dams) by 2045.

PCE is pursuing a plan to have 100% of its load served by renewable resources by 2025—nearly 20 years ahead of the state mandate. This PCE policy is reflected in the analysis.

Energy Storage. Assembly Bill (AB) 2514 requires LSEs to procure energy storage capacity. The storage mandate was implemented by the CPUC through a requirement that CCAs procure energy storage equal to one percent of their forecasted 2020 peak load. Some energy storage technologies, especially lithium-ion batteries, have fallen steeply in cost in recent years, though they are still relatively

POWER PRIMER

The California Independent System Operator (CAISO) manages the balance between electricity load and supply on its system. Each utility, CCA or energy service provider (ESP) on the CAISO system provides, each day, a forecast of its load and the resources it will be using to meet that load. These load serving entities' (LSEs) forecasts are updated throughout the day by the LSE's "scheduling coordinator." The CAISO also maintains markets for power plants to be standing by to meet unexpected load, or to back off production if load is lower than forecast.

For LSE planning and procurement purposes, electricity supply consists of two components: energy in kilowatt hours (kWh), and capacity or demand in kilowatts (kW). Using an analogy of a railroad car: the size of the car represents capacity; and the goods inside the car represent energy. A CCA must purchase both energy (kWh) to meet its customer's consumption needs and capacity to account for customer demand. The CCA must always purchase both the correct amount of energy (kWh) and an adequate amount of capacity to meet its customers' energy requirements. As such, the CCA must appropriately forecast both energy usage (kWh) and peak demand (kW) requirements of its customers.

[20] In practice, the utility code establishes multi-year compliance periods ending in 2020, 2024, 2027 and 2030, with the average renewable energy supply as a percentage of retail sales for each compliance period required to be 33%, 44%, 52%, and 60%, respectively.

expensive compared to supply resources and demand response. Battery costs are expected to continue to fall, suggesting there is a benefit to deferring procurement until required by the mandate.

PCE already has plans for a large storage project, which will be attached to the Wright Solar project in Los Banos, and other additional storage in the next few years. This PCE policy is reflected in the analysis.

Resource Adequacy. Since 2006, all LSEs that serve load on the California grid managed by the CAISO are responsible for complying with Resource Adequacy (RA) obligations. There are three components to the RA compliance program:

1) **System** capacity requirements to meet expected peak loads within the entire CAISO system.
2) **Local** capacity requirements to meet contingency needs in locally constrained areas; and
3) **Flexible** capacity requirements to meet the largest continuous three-hour load increase ("ramp") in each month.

Specifically, to meet the System RA requirement, load serving entities must contract for 115% of their projected monthly peak demand as determined by the CPUC in consultation with the California Energy Commission load forecasts.

The Local RA requirement must be met by LSEs with customers in 10 local reliability areas identified by the CAISO. The Local RA requirements are set three years ahead and updated each year. LSEs are required in their annual filings to show that they meet 100% of local requirements for the next two years and 50% of the third-year requirement.[21] In early 2020, the CPUC approved a "Central Procurement Entity" (CPE) to take over the procurement of Local RA. The applicable CPE for PCE is PG&E. Starting in 2023, PCE, along with the other CCAs in PG&E's territory, will no longer have to acquire—and pay for—Local RA. Instead, PG&E will acquire local RA for its territory and pass on the costs directly to the customers via a new nonbypassable rate.

The CAISO also determines the required Flexible RA needs and operating criteria. LSEs must demonstrate purchase of 90% of their flexible RA requirement in their annual RA filing, and 100% of the requirement in their monthly RA filings.[22]

There is a bilateral market for RA capacity, with standardized products for system, local, and flexible RA capacity.

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[21] Note that Local RA capacity is a substitute for System RA capacity. However, the converse is not always true, meaning that System RA capacity might not help an LSE meet its Local RA requirements.
[22] Flexible RA can substitute for System RA and possibly for Local RA but the converse is not always true: System and Local RA resources might not help an LSE meet its Flexible RA obligations.

PCE receives modest RA credit from its existing power purchase agreements but must enter into additional contracts for its RA-compliant capacity.

Power Supply Portfolio and Cost Assumptions

Because this analysis considers the costs and benefits of adding Los Banos to PCE, we start with PCE loads and resources and consider the incremental additions that would be required to serve the additional load that Los Banos would add. This requires the consideration of the power resources that PCE already has under contract as well as the one that its longer-term plans suggest it will add over the next ten years. Once those resources are accounted for, we then consider the additional resources that PCE would need to acquire to serve Los Banos.

Existing Contracts

PCE has eight power purchase contracts in place that will provide energy during the forecast period, plus two that are currently in negotiation. Except for one 38 MW wind contract whose last delivery year is 2022, these contracts are summarized in Table 5. Highlighted is the Wright Solar + Storage project, located in Los Banos, which provides over ½ million MWhs per year to PCE—about 1/7th of PCE's total energy needs.

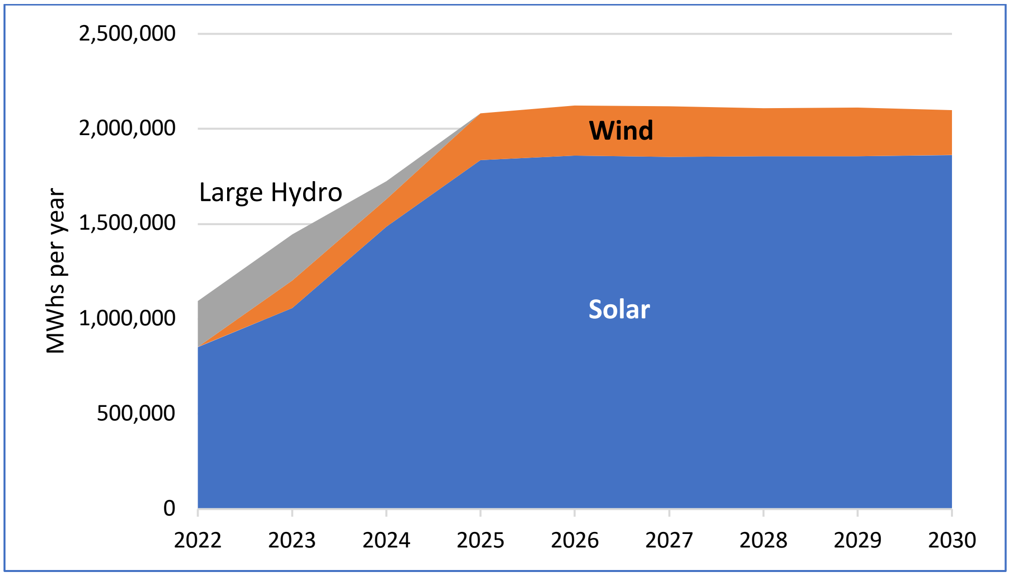
Table 5. Existing PCE Supply Contracts Providing Power in 2023-2030

Status	Provider	Technology	Capacity (MW)	Annual Energy (MWhs)
Signed	Bidwell	Small Hydro	2	11,000
Signed	Hatchet	Small Hydro	7.5	17,000
Signed	Roaring	Small Hydro	2	6,000
Signed	Clover	Small Hydro	1	4,000
Signed	Mustang	Solar	100	294,000
Signed	***Wright***	***Solar***	***200***	***542,000***
Signed	Shiloh	Wind	150	418,000
In negotiation	Existing Wind	Wind	32.5	108,000
In negotiation	New Solar	Solar	100	293,000
In negotiation	New Storage	Storage	147	n/a
		Total Small Hydro	**12**	**38,000**
		Total Solar	**400**	**1,129,000**
		Total Wind	**183**	**526,000**
		Total Storage	**147**	

Projected New Resources

Every other year, every LSE that is regulated by the CPUC must file an Integrated Resource Plan IRP). These plans show how each LSE intends to serve its load such that in total all the LSEs combined meet the State's greenhouse gas reduction goals. PCE's recent IRP shows that it plans to acquire from 800,000 to 1,800,000 MWhs from new solar facilities, 150,000 to 250,000 MWhs from wind resources and up to 240,000 MWh from large hydroelectric dams. (see Figure 12.)

Figure 12. PCE's Planned Additions per IRP



Wholesale Market Sales and Purchases

Even though PCE has contracts in place to meet most of its needs, it still buys and sells power into the wholesale market run by the power grid operator (CAISO). In some hours, PCE must sell excess power into this market. This occurs most typically on spring afternoons, when PCE's solar projects are generating more power than PCE's customers can consume. Similarly, there are hours in the evening and at night when PCE must purchase power from the wholesale market.

The prices in this market change from month to month and from hour to hour. MRW relied upon a wholesale power price forecast provided by PCE. This the same forecast that PCE relies upon for its planning and budgeting.

Incremental Resources to Serve Los Banos

PCE's Integrated Resource Plan does not include Los Banos. Therefore, MRW had to make assumptions about what it would cost PCE to serve the larger load it would have with the City.[23]

[23] Even though PCE would have to add additional power resources if Los Banos joins the JPA, Los Banos, as a PCE member, would still receive a share of the output of the Wright Solar Project.

This study assumes that PCE would purchase power using renewables priced at the wholesale market price plus an adder to reflect the cost of a bundled Renewable Energy Credit ("Bucket 1" REC).[24] These contracts typically have an adder of about $17/MWh (1.7¢/kWh). In practice, once Los Banos is included in the PCE load, PCE would enter into additional long-term contracts to cover the additional load at prices that would likely be less than the market plus REC price. As such, MRW sees this purchasing assumption as conservative.

Grid Charges

The CAISO, which operates the power grid that connects PCE's loads to its resources, charges the LSEs that move power on the grid in order to cover its costs of management and operation. These costs are assumed to be 5.5% of PCE's energy.

Capacity Costs

As noted above, CCAs are also responsible for complying with Resource Adequacy (RA) obligations. These products are typically contracted on a short-term basis (e.g., year-ahead). Up until 2019, there was an excess supply of both system and flexible capacity in the market, leading to depressed prices for these products. This changed dramatically in 2019, when RA prices doubled.

MRW used PCE's proprietary forecast of RA costs for this study.

Modeling

MRW's models look at each hour in the study period, and lines up the load that must be met (be it PCE alone or including Los Banos) and the power available to PCE from its existing contracts. If the load exceeds the power provided by the PCE contracts, then the incremental amount is met at the wholesale market price. In hours where the power production from PCE's contracts exceed PCE's load, the model sells the excess output to the wholesale market at that hour's price. If the annual output of PCE's contracts equal in total the load it services (which is the goal), then the amount of excess power sold into the wholesale market will equal the amount that is purchased from the wholesale market.

Pro Forma Elements and CCA Costs of Service

This section outlines the main elements of the pro forma analysis, the assumptions underlying the elements and the output results. The analysis involves a comparison between the generation-related costs that would be paid by Los Banos CCA customers and the generation-related costs that would be paid by PG&E bundled service customers. Costs paid by CCA customers include all CCA-related costs (*i.e.*, supply portfolio costs and administrative and general costs) and exit fee payments that CCA customers will be required to make to PG&E.

[24] Renewable Energy Credits are the property rights to the non-power attributes (typically environmental or social attributes) of renewable electric generation. These certificates are issued for every MWh of electricity that is generated by a renewable energy resource and delivered to the electric grid.

As discussed in previous sections, supply portfolio costs are informed and affected by CCA loads, by the requirements the CCA will need to meet (or will choose to meet) such as with respect to renewable procurement, and by CCA participation levels. Administrative and general costs are discussed further below.

Startup costs

Startup costs are the costs PCE will incur before beginning to serve Los Banos**.** Table 6 shows these estimated startup costs. They are based on the experience of existing CCAs as well as information from other CCA technical and feasibility assessments.

Table 6. Estimated Start-Up Costs

Item	Cost
Organizational/Administration	
Professional Services/Consulting	$50,000
Staffing	$40,000
G&A costs (office rent, deposits, equipment, software, insurance, etc.)	$15,000
Total:	**$105,000**
Communications/Customer Enrollment	
PR/Advertising Campaign -- print, social, paid and earned media	$15,000
Materials for tabling and events (design/print)	$5,000
Customer Notifications (4 x 17k @ $ 0.85 each) *	$57,800
Community Sponsorships, etc.	$5,000
Total:	**$82,800**
GRAND TOTAL:	**$187,800**

Administrative and General Cost Inputs

Administrative and general costs cover the everyday operations of the CCA, including costs for billing, data management, customer service, employee salaries, contractor payments, and fees paid to PG&E. Table 7, below summarizes PCE's projected ongoing administrative and general costs through 2025 and are assumed to trend with inflation from 2026 onward (about 2% per year).

Table 7. PCE's Forecast Administrative and General Costs ($ Thousands)

	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030
Staff compensation	$6,237	$6,787	$7,119	$7,468	$7,834	$8,007	$8,183	$8,363	$8,547
Data Manager	$3,420	$3,454	$3,489	$3,524	$3,559	$3,637	$3,717	$3,799	$3,883
Service Fees - PG&E	$1,260	$1,273	$1,285	$1,298	$1,311	$1,340	$1,369	$1,400	$1,430
Consultants & Professional Services	$3,068	$4,176	$2,898	$2,442	$2,422	$2,476	$2,530	$2,586	$2,643
Legal	$1,708	$1,706	$1,753	$1,798	$1,854	$1,895	$1,937	$1,980	$2,023
Communications and Noticing	$2,873	$2,966	$2,228	$2,335	$2,448	$2,502	$2,557	$2,613	$2,671
General and Administrative	$1,947	$2,071	$2,588	$2,658	$2,732	$2,792	$2,853	$2,916	$2,980
Community Programs	$7,550	$10,435	$10,870	$10,950	$11,000	$11,242	$11,489	$11,742	$12,000
Depreciation	$133	$169	$205	$241	$277	$283	$290	$296	$302
Total Operating Expenses	**$28,197**	**$33,038**	**$32,436**	**$32,714**	**$33,438**	**$34,174**	**$34,926**	**$35,694**	**$36,479**

The analysis assumed that PCE's administrative and general costs would increase by 5% if Los Banos is added. This is likely conservative; not all costs (e.g., consulting and legal) would necessarily increase with the addition of Los Banos.

Note also that approximately 1/4th of PCE's administrative and general costs go towards community programs.

PG&E Rate and PCIA Forecasts

PG&E Generation Rates

Forecasts of PG&E's generation rates and exit fees are necessary to compare the projected rates that customers would pay as Los Banos CCA customers to the projected rates and fees they would pay as bundled PG&E customers.

To ensure a consistent and reliable financial analysis, a 10-year bottom-up forecast of PG&E rates was developed using market prices that are consistent with those used in the forecast of PCE's supply costs. The forecasted costs include the cost of PG&E's existing resource portfolio, adding in market purchases only when necessary to meet projected demand.

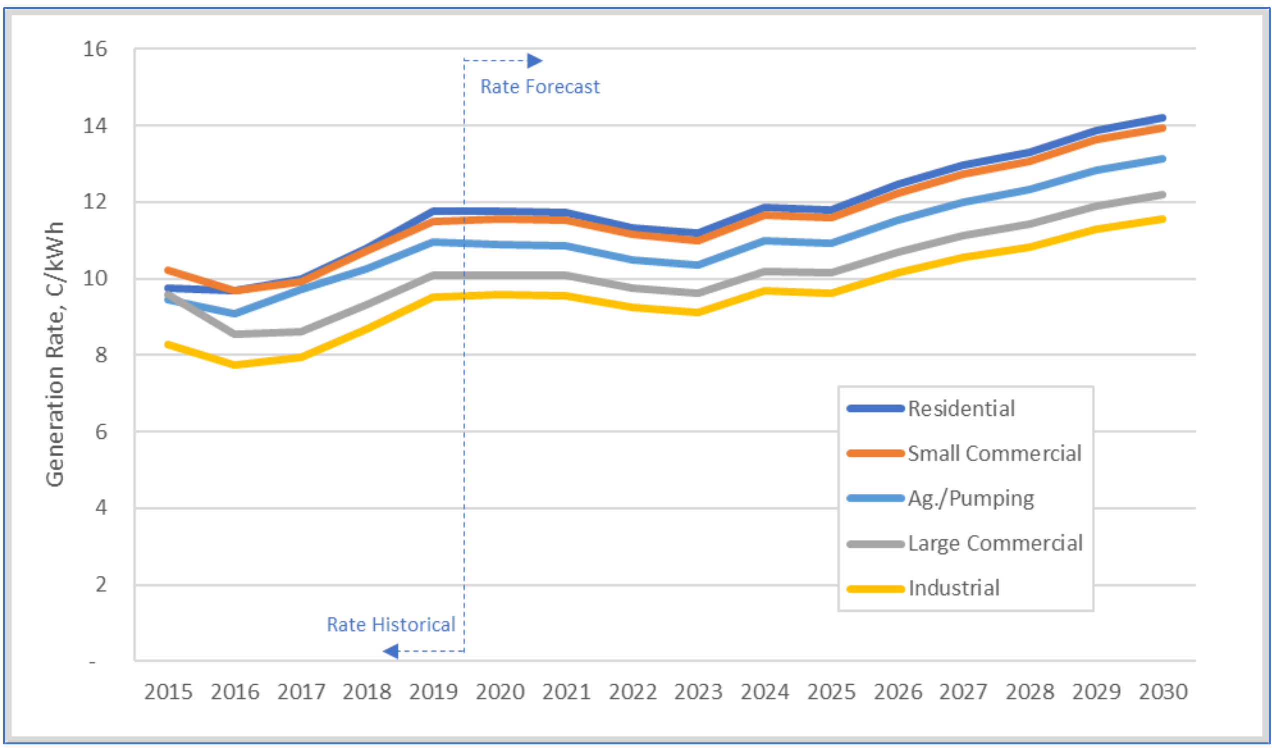
To develop this forecast, the key cost drivers of each of PG&E's generation rate components were examined, separately evaluating costs for renewable and non-renewable energy purchases, for PG&E-owned generation facilities, and for capacity purchases. The study assumed that nearterm changes to PG&E's generation portfolio would be driven primarily by modest increases in underlying gas market prices and changes to its power purchase portfolio (e.g., the retirement of the Diablo Canyon Nuclear Power Plant in 2024-2026).

The forecast further assumes that PG&E is compliant with the renewable and carbon-free requirements recently ordered in Senate Bill 100: a minimum of 60% renewable content in 2030 and a trajectory that would, when extrapolated, result in carbon-free power in 2045. In fact, given the current PG&E renewable portfolio and the loss of load from the many CCAs being formed in northern California, PG&E could be nearly carbon free in the next few years.

The forecast for PG&E's generation resources are based on publicly available data and forecasts. As with the CCA cost forecast, we relied on the market price forecast provided by PCE to estimate the cost of market purchases. However, since PG&E protects data that would reveal its detailed power procurement activities (e.g., hedging), we were unable to perform the hourly analysis completed for PCE and instead relied on average market prices to develop estimates of the cost of PG&E market purchases.

Over the 10-year period, the study forecasts that PG&E's generation rates will escalate by an average of 2.8% per year. This forecast, along with historical rates, is show in Figure **13**, below.

Figure 13**. Historical and Forecasted PG&E Average Generation Rates**



Power Charge Indifference Amount (PCIA)

The Power Charge Indifference Adjustment (PCIA) is a fee charged by PG&E intended to prevent customers that remain with PG&E bundled service from paying for energy generation procured on behalf of customers that have since switched to CCA service. More specifically, it pays for the above-market costs of PG&E generation resources that were acquired, or which PG&E committed to acquire, prior to the customer's departure to CCA.

The total cost of these resources is compared to a market-based price benchmark to calculate the "stranded costs" associated with these resources, and CCA customers are charged what is determined to be their fair share of the stranded costs through the PCIA. Bundled customers also pay the PCIA, which is embedded into their commodity portion of their total rate.

Because PG&E is constantly acquiring new generation resources, the PCIA for customers who began CCA service earlier are responsible for the above market costs of fewer resources than customers who begin CCA service later. This is known as PCIA "Vintages." PCE's current load is Vintage 2016, while if Los Banos joins PCE in 2022, its load would be assigned a "2021" vintage.[25] Because PG&E has added very few new resources between 2016 and 2021, the 2021 Vintage PCIA, paid by Los Banos customers, would be about the same as the 2016 Vintage PCIA, which is paid by PCE customers.

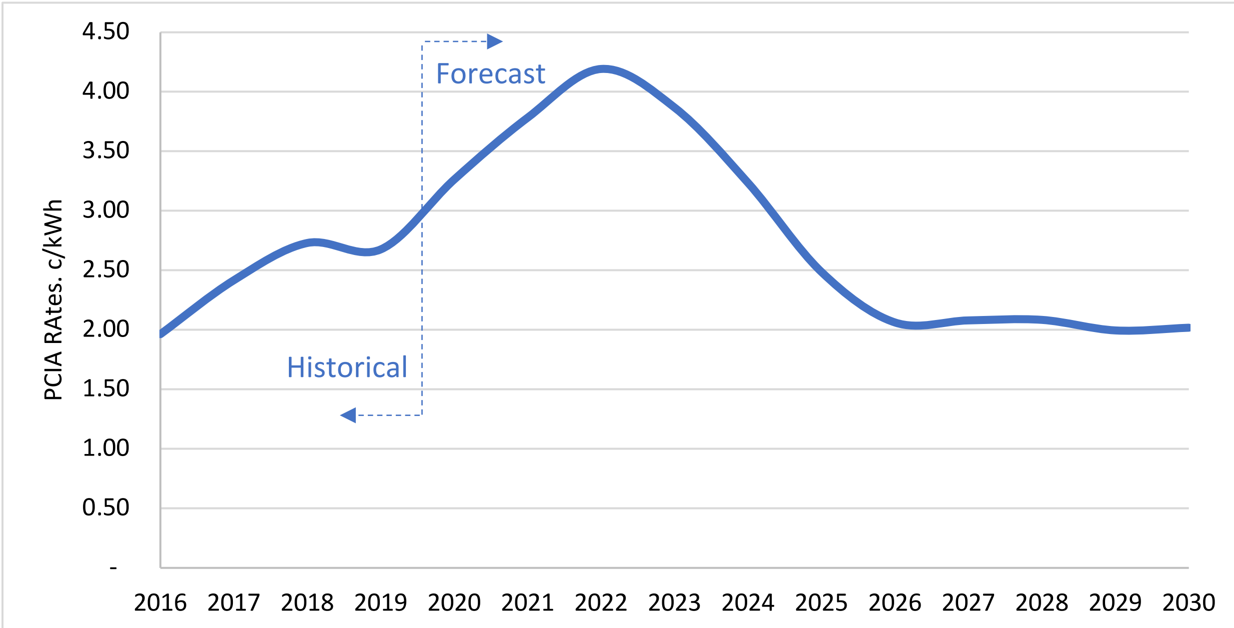
The PCIA is not paid directly by the CCA, but by the individual customers taking CCA service. Thus, it does not appear explicitly on the CCA's books, however it must be accounted for in any CCA cost analysis. While both CCA customers and customers that choose to remain in PG&E bundled service pay this fee, it appears as a separate line item for CCA customers and is embedded in the energy generation costs of PG&E bundled customers.

To forecast the PCIA, this study used the formula and approach dictated by CPUC Decision 18-10-019. In addition, the market price and PG&E portfolio assumptions used in the PCIA calculations are consistent with those used to forecast PG&E's generation rates.

This study forecasts the PCIA charge by directly modeling expected changes to PCIA-eligible resources and to the market-based price benchmark through 2030. Based on our modelling, we expect the PCIA start at around 4.4¢/kWh and decrease such that by 2023, the PCIA is about 2.1¢/kWh. This decrease is due to the expiration of certain expensive contracts, the retirement of Diablo Canyon Nuclear Power Plant, and general market price increases. MRW's forecast of the PCIA charge through 2030 is shown below.

[25] The PCIA vintage and calendar year does not exactly match.

Figure 14. Historical and Forecasted Average PCIA



Chapter 3. Cost and Benefit Analysis

Costs and benefits are evaluated by comparing the total average cost to serve the CCA customer (cents per kWh or dollar per MWh) (including PCIA) to PG&E generation rates.

The pro forma results for the first 9 years of the Los Banos joining PCE (2022-2030) are summarized in this chapter.

Rate Comparisons

Figure 15 shows the forecast of PCE's average cost of service and PG&E's generation rates. The bars in the chart show the forecasts of the major cost components of CCA operation, while the single line shows the forecast of PG&E's retail generation rate. When the bars are below the line, PCE's average operating costs is lower than PG&E's generation rate; meaning that it can offer power to customers at a rate lower than PG&E. As the figure shows, but for the first year, 2022, PCE's forecast cost of service is below our forecast of PG&E's generation rate.

The bottom-most blue segment represents the cost of power to the CCA. The next segment up, orange, is the cost to acquire the capacity needed to comply with the state's resource adequacy program. That is, the cost that PCE must incur to demonstrate that it has the generating capacity (in megawatts) to ensure that it can serve all its load, even if the "intermittent" renewable resources are not generating at their optimal rate (e.g., solar on rainy days). The more intermittent renewables—solar and wind—that are added to the CCA's generating mix, the more back-up capacity is needed to ensure reliability.

The next segment, gray, is for costs that PCE must pay to the grid operator.

The next segment, yellow, is PCE's administrative and general costs. This includes all the costs PCE requires to operate (staff, rent, equipment, professional services) as well as the costs of PCE's service programs to its members.

The top-most green segment is for the Power Charge Indifference Adjustment (PCIA) and the Franchise Fee. The PCIA is a fee paid to PG&E to ensure that the operation of the CCA does not strand PG&E's remaining bundled customers with costs associated with power purchased on behalf of customers who have shifted to the CCA. Franchise fees are those collected by PG&E and paid to the City for the right to operate the electric monopoly franchise in the city. It is paid as a percent of each customer's total bill and is automatically built into PG&E's rates. So that cities remain financially whole when customers' power is provided by a CCA, PG&E charges CCA customers a "franchise fee surcharge."[26]

The black line represents PG&E's average generation rate. The difference between the PG&E generation rates and the PCE cost plus PCIA columns is the amount that is available for rate discounts, contributions to cash reserves, or funding additional programs. In 2022, because the

[26] See PG&E Tariff Schedule FFS.

sum of the costs approximately equals the PG&E generation rate, PCE will need to dip into its cash reserves to as to maintain its commitment to offer a 5% discount.

Figure 15. Forecast of PCE's Cost of Service (Without Los Banos) Versus PG&E's Generation Rate

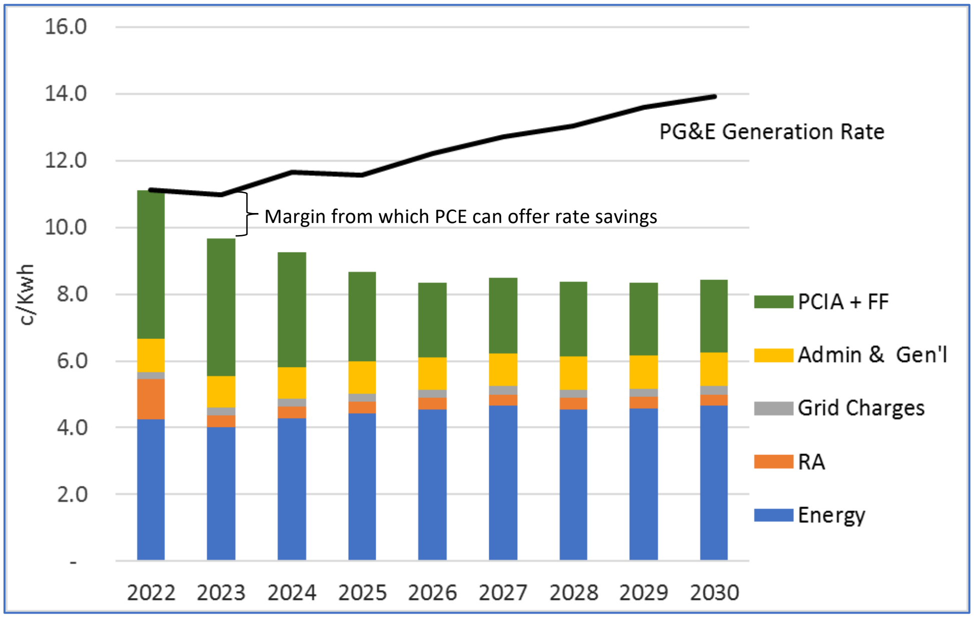


Figure 16 shows the same comparison as Figure 15, except that it assumes that PCE is serving Los Banos, too. The two figures are nearly identical, the only discernable difference can be seen in 2022, where the cost + PCIA column is slightly higher relative to the generation rate line.

Table 8 shows the annual average cost of service (i.e., the elements of the columns except for the PCIA) for PCE alone and PCE with Los Banos. The table shows that adding Los Banos will increase PCE's cost of service by an average of 0.05¢/kWh, which is less than one percent. As discussed below, this average cost increase is more than compensated for by the additional revenues that Los Banos would bring into PCE.

Figure 16. Forecast of PCE's Cost of Service (With Los Banos) Versus PG&E's Generation Rate

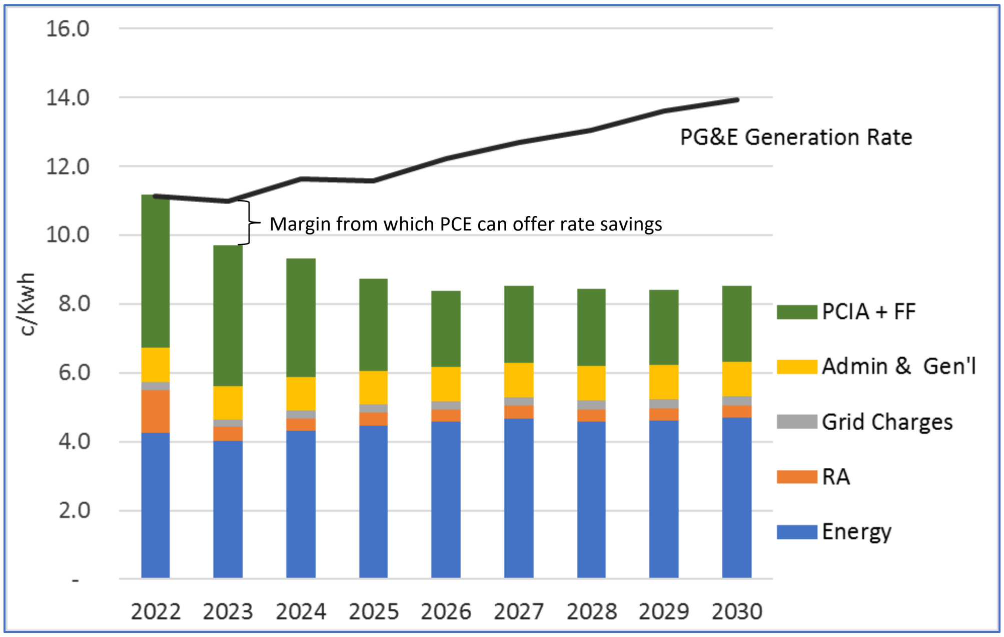


Table 8. Average PCE Cost of Service (¢/kWh)

	2022	2023	2024	2025	2026	2027	2028	2029	2030
PCE Alone	6.78	5.84	6.00	6.14	6.25	6.36	6.25	6.30	6.38
PCE With Los Banos	6.83	5.88	6.05	6.20	6.30	6.41	6.31	6.37	6.45

Financial Impact on PCE of Adding Los Banos

MRW quantified the financial impact on PCE of adding Los Banos by comparing the changes in its cost of service and revenues. As shown in Table 9, over the nine year study period, adding Los Banos increases PCE's costs by $111 million while increasing its revenues by $135 million. This results in a net benefit of about $24 million, or 1%. However, the impact is not equal. In the earlier years, PCE incurs a net cost to serve Los Banos, with a break-even year of 2026.

Table 9. Change in PCE's Costs and Revenues from Adding Los Banos (millions $)

Year	Change in Costs	Change in Revenues	Net Benefit (Cost)	Net Benefit as % of Costs	Cumulative Net Benefit
2022	$13.0	$10.6	($2.4)	-1.1%	($2.4)
2023	$10.9	$10.7	($0.2)	-0.1%	($2.6)
2024	$11.5	$12.9	$1.4	0.7%	($1.2)
2025	$11.9	$14.0	$2.1	1.0%	$0.9
2026	$12.3	$15.9	$3.7	1.7%	$4.5
2027	$12.4	$16.7	$4.3	1.9%	$8.9
2028	$12.6	$17.3	$4.6	2.1%	$13.5
2029	$13.0	$18.3	$5.3	2.3%	$18.8
2030	$13.1	$18.7	$5.7	2.4%	$24.4
Total	**$110.7**	**$135.1**	**$24.4**	**1.2%**	**$24.4**

Chapter 4. Sensitivity of Results to Key Inputs

The results shown in the Scenarios above reflect expected market conditions and outcomes with variations only in the amount and type of renewable generation. However, it is unlikely that the conditions assumed in these Scenarios will occur exactly as assumed. In order to evaluate the robustness of the analysis, the key variables must be identified, and analyses conducted with other assumptions for those key variables to “stress test” the assumptions. Three cases were investigated: A higher PCIA forecast, a lower PG&E generation rate forecast, and the higher PCIA and lower generation rate forecast together. Raising the PCIA or lowering the PG&E generation rate both impact the rate that PCE charges, as its rates are tied to PG&E’s. Thus, in these sensitives, the rate that PCE can charge is decreased while its costs remain the same.

The specific assumptions on the sensitivity Scenarios are shown in Table 10 and Figure 17 and Figure 18.

Table 10. Sensitivity Case Definitions

Sensitivity Case	Definition
Base	Per MRW Forecasts
Higher PCIA	PCIA decreases ½ as much as in Base
Lower PG&E Generation Rate	PG&E generation rates escalate at 1% per year

Figure 17. Higher PCIA Sensitivity Case

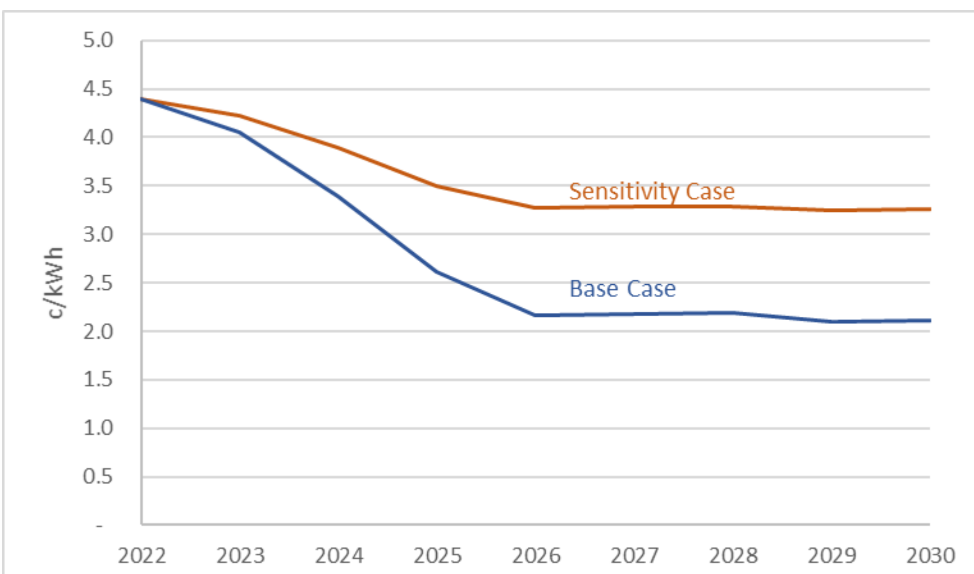
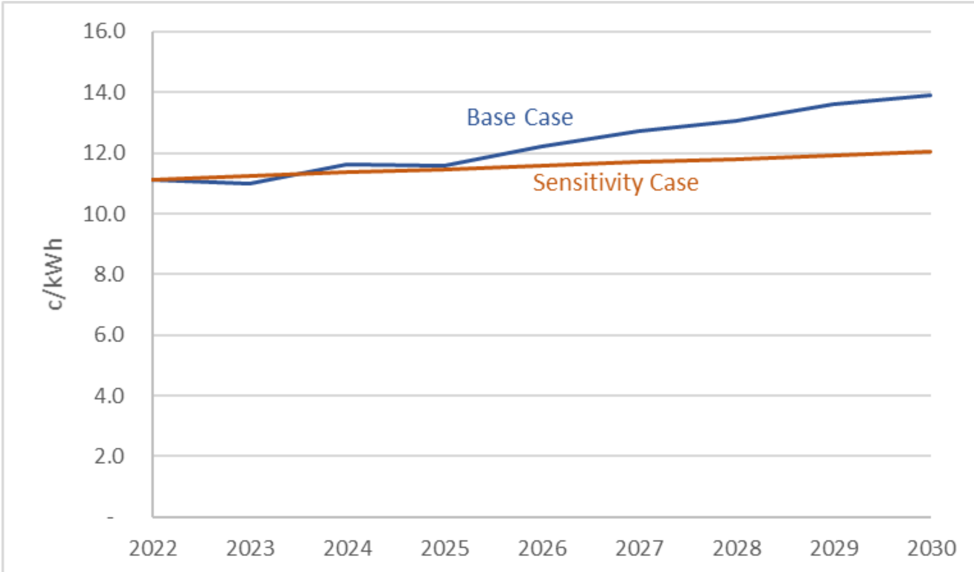


Figure 18. Lower Generation Rate Sensitivity Case



Sensitivity Results

Higher PCIA Sensitivity

The models used to create this report explicitly simulate the calculation of the PCIA. Therefore, underlying changes to the market—higher or lower natural gas or high or lower renewable costs--explicitly ripple through to the PCIA. However, for the sake of interest and conservatism, this sensitivity represents a case where the PCIA decrease shown in the Base Case is halved (Figure 17). This assumption reduces the rates that PCE charge by up to 2¢/kwh.

The impact on PCE's finances is show in Table 11. As the table shows, with the higher PCIA assumption, the total benefit of adding Los Banos to PCE would be approximately 50% of the Base Case benefit: $12 million versus $24 million. In this case, it would require until 2027 before the cumulative benefit exceeds the costs.

Table 11. Financial Impact on PCE of Higher PCIA

Year	Change in Costs	Change in Revenues	Net Benefit (Cost)	Net Benefit as % of Costs	Cumulative Net Benefit
2022	$13.0	$10.4	($2.6)	-1.2%	($2.6)
2023	$10.9	$10.3	($0.6)	-0.3%	($3.3)
2024	$11.5	$11.9	$0.4	0.2%	($2.8)
2025	$11.9	$12.4	$0.5	0.3%	($2.3)
2026	$12.3	$14.1	$1.8	0.8%	($0.5)
2027	$12.4	$14.8	$2.4	1.1%	$2.0
2028	$12.6	$15.4	$2.8	1.2%	$4.7
2029	$13.0	$16.3	$3.3	1.5%	$8.0
2030	$13.1	$16.8	$3.7	1.6%	$11.8
Total	$110.7	$122.5	$11.8	0.6%	**$11.8**

Lower PG&E Rate Sensitivity

As a conservative sensitivity, MRW explored the impact of assuming that the PG&E generation rate increased at 1% per year, rather than the fundamentals-derived forecast, which resulted in an average PG&E generation rate increase of 2.8% per year.

The impact on PCE's finances is show in Table 12. As the table shows, with the lower PG&E generation rate assumption, the total benefit of adding Los Banos to PCE would be approximately 45% of the Base Case benefit: $14 million versus $24 million. However, in this case, it would require until only until 2023 before the cumulative benefit exceeds the costs.

Table 12. Financial Impact on PCE of Lower PG&E Generation Rate

Year	Change in Costs	Change in Revenues	Net Benefit (Cost)	Net Benefit as % of Costs	Cumulative Net Benefit
2022	$13.0	$10.6	($2.4)	-1.1%	($2.4)
2023	$10.9	$11.1	$0.2	0.1%	($2.2)
2024	$11.5	$12.4	$0.9	0.4%	($1.3)
2025	$11.9	$13.8	$1.9	0.9%	$0.6
2026	$12.3	$14.9	$2.7	1.2%	$3.3
2027	$12.4	$15.1	$2.7	1.2%	$6.0
2028	$12.6	$15.3	$2.7	1.2%	$8.6
2029	$13.0	$15.6	$2.6	1.1%	$11.2
2030	$13.1	$15.8	$2.7	1.1%	$13.9
Total	$110.7	$124.6	$13.9	0.7%	**$13.9**

Combined Sensitivity

Table 13 below shows the financial impact on PCE of the lowering PG&E generation rate escalation and using the higher PCIA assumption. As the table shows, under this scenario PCE breaks even in 2029 if Los Banos is added. The impact is very nominal, +0.1% of PCE's revenue, which given all the assumptions going into the analysis is within the margin of error.

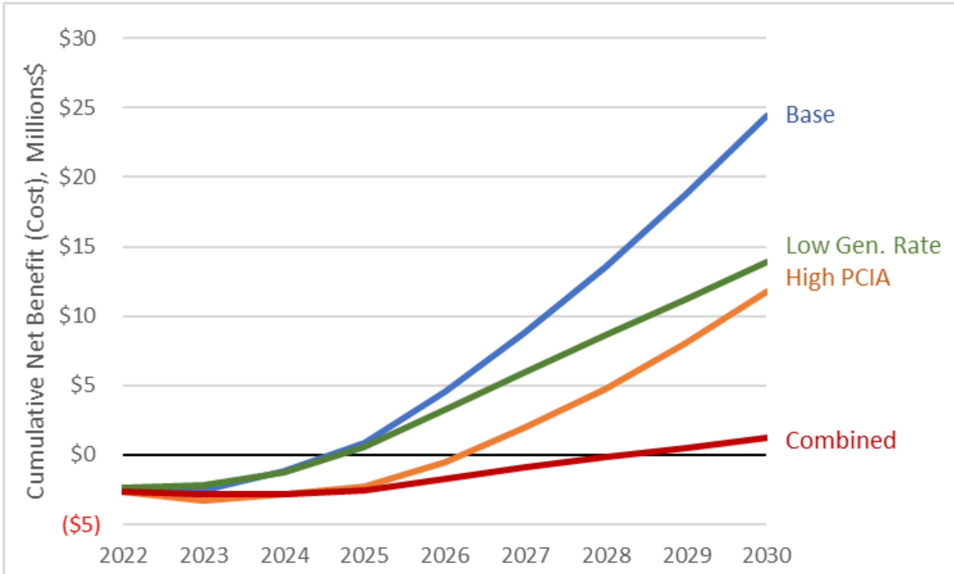
Table 13. Financial Impact on PCE of Lower PG&E Rate and Higher PCIA

Year	Change in Costs	Change in Revenues	Net Benefit (Cost)	Net Benefit as % of Costs	Cumulative Net Benefit
2022	$13.0	$10.4	($2.6)	-1.2%	($2.6)
2023	$10.9	$10.7	($0.2)	-0.1%	($2.8)
2024	$11.5	$11.5	($0.1)	-0.0%	($2.9)
2025	$11.9	$12.3	$0.4	0.2%	($2.5)
2026	$12.3	$13.0	$0.8	0.3%	($1.8)
2027	$12.4	$13.2	$0.8	0.4%	($0.9)
2028	$12.6	$13.4	$0.8	0.3%	($0.2)
2029	$13.0	$13.7	$0.7	0.3%	$0.5
2030	$13.1	$13.8	$0.8	0.3%	$1.3
Total	$110.7	$112.0	$1.3	0.1%	**$1.3**

Sensitivity Case Implications

As shown in Figure 19, in the Base case and all three sensitivity cases there is a net cost to PCE of adding Los Banos for the first few years. PCE's negative "investment" in Los Banos breaks even within the first five years (i.e., cumulative net benefits become positive) in all but the Combined High PCIA/Low Generation Rate sensitivity. There, the net benefits remain negative through at least 2028.

Figure 19. Fiscal Impact of Los Banos Joining PCE (sensitivity cases)



From Los Banos's point of view, as long as PCE is committed to keeping its customers net generation rates at 5% less than PG&E's, how long it takes PCE to recoup the first years' costs is immaterial. Furthermore, given the very modest overall financial impact adding Los Banos has to PCE, MRW finds it unlikely that adding Los Banos would change PCE's rate setting policy.

From PCE's perspective, its Board must weigh the initial negative financial impacts, albeit modest, of adding Los Banos against the long-run benefits of the expansion.

Chapter 5: Risks & Mitigating Strategies

As discussed so far, there are potential benefits to CCA formation, but there are also risks. This chapter lists many of the larger risks that a Los Banos CCA would face—and in fact all CCAs must deal with—along with summaries of how the CCA can address the risk.

Financial Risk to City

Like all other CCA JPA agreements that MRW has seen, the PCE agreement explicitly isolates its finances and liabilities from those of its members. In the event of an PCE failure or default, MRW understands that its member jurisdictions could not be held liable for the JPAs debts or obligations. Nor do any CCA obligations appear on the city's books or impact its credit rating.

If PCE was having financial difficulties and had to charge rates that exceeded PG&E's, then the city, as a JPA member, might feel obligated to remain with PCE service at a higher cost rather than revert back PG&E. While this is possible and might occur in an isolated year, MRW believes, given its track record and policies, that PCE can, over the long run, meet or beat PG&E's rates.

The primary financial risk to the City would be if it joined PCE but subsequently left it after the JPA had entered into power contracts to serve the City's load. In that circumstance, the JPA agreement allows the JPA to impose fees to compensate it for any excess costs caused by the City's departure. For PCE, a jurisdiction may withdraw its participation in the CCA Program at the beginning of PCE's fiscal year by giving at least 6 months advance written notice. It can also withdraw if an amendment is made to the JPA and the party gives 30 days' notice.[27] Withdrawals and terminations require a director vote.[28] Even after the jurisdiction is no longer part of the CCA, it may still have financial obligations including losses from the resale of power.[29] However, if the City withdraws its membership prior to the program launch, it bears no financial obligation.[30]

The City will not lose any revenue associated with franchise fees.[31] PG&E's Electric Rule 23, Section B.16 explicitly states that "CCA customers shall continue to be responsible to pay all applicable fees, surcharges and taxes as authorized by law. PG&E shall bill customers for franchise fees as set forth in Public Utilities Code Sections 6350 to 6354." Since PG&E's retail sales to CCA customers does not include the generation component of rates, a special adjustment must be made to ensure that a city participating in a CCA receives its fully due franchise fees.

Mitigation: Joining a JPA like PCE provides better protections to the City's finances by more firmly isolating the CCA's books from that of the City as well as providing greater resources to

[27] JPA p. 11
[28] JPA p. 11-12
[29] JPA p. 12
[30] JPA p. 11
[31] Franchise fees are payments that a public utility makes to a city or county government for the nonexclusive right to install and maintain equipment on the government's right of ways. Franchise fees are generally calculated as a fraction of retail sales, typically on the order of a few percent.

manage its procurement and programs. It can further be mitigated by understating that CCA is a commitment for the long run, and plan for, and be willing to work through, times where the CCA rates may not be as favorable as the City might like.

Opt-Out Risk

Customers may choose to opt-out of a CCA service before or during their transfer to CCA, or in fact at any time. The opt-out risk comes at two district time periods. The first is the initial roll-out of the CCA program. The most recent CCA launches have experienced only very modest opt-outs: around two to three percent of the eligible customers have elected not to take service from their CCA.[32] If there are negative communications to Los Banos citizens and businesses during the initial roll out (e.g., bad press of some sort), then the opt-out rate could increase. Second, customers could choose to leave CCA service after the initial opt-out period. The most likely driver of this opt-out risk is expanding Direct Access eligibility, which is addressed in more detail below.

Mitigation*:* The experience of prior CCAs suggests that opt-outs at the beginning of service tend to be in a relatively narrow range, allowing for some predictability in initial opt-outs. The value used in the study, 5%, is well withing the average. In addition, prudent power procurement strategies will allow for a reasonable uncertainty in load, especially that associated with DA expansion, without having to either dump power at a loss or purchase excessive amounts at high spot market prices. CCAs also may be able to charge an "exit fee" akin to the PCIA to customers who have left CCA service after power contracts have been signed to serve their load, but to date none have been imposed.

Rate and PCIA Uncertainty

A primary objective is to offer power to Los Banos residents and businesses at a competitive price relative to PG&E. In this circumstance, competitiveness is tied to the rate offered by PG&E. A number of factors can cause a Los Banos CCA's or PCE's net power costs to exceed those of PG&E. The CCA must have in place risk management plans and options to both mitigate these risks by lowering rates passed on to customers back down to a competitive rate as well as to address unexpected risks.

Changes to PG&E Generation Rates: There could be circumstances that result in PG&E's generation' rates being less than a Los Banos CCAs or PCE. Assuming that PG&E's rates are based on its cost of service, Los Banos CCA obviously has little or no ability to influence the rates that PG&E offers.

Mitigation: While a Los Banos CCA or PCE has little ability to affect PG&E's generation rates, it can take proactive steps to mitigate the impact of reductions in PG&E's generation rate through participation in rate proceedings at the CPUC and through soundly managing its own

[32] The exception to this is the large industrial customers in CPA's CCA. CPA chose not to offer competitive rates to these customers as the CCA could not cover the cost to serve them. The large opt-out, over 50%, was not unexpected and was planned for.

finances. We note at PCE is participating in CPUC rate proceedings and has been professionally managed.

Changes to PG&E's PCIA Rate: Assembly Bill 117, which established the Community Choice Aggregation program in California, included a provision that states that the customers that remain with the utility should be "indifferent" to the departure of customers from utility service to CCA service. This has been broadly interpreted by the CPUC to mean that the departure of customers to CCA service cannot cause the rates of the remaining utility "bundled" customers to go up. To maintain bundled customer rates, the CPUC has instituted an exit fee, known as the "Power Charge Indifference Amount" or "PCIA" that is charged to all CCA customers. The PCIA is intended to ensure that generation costs incurred by PG&E before a customer transitions to CCA service are not shifted to remaining PG&E bundled service customers.

Thus, for a Los Banos CCA customer to realize an economic benefit (i.e., pay the same or less for electricity), the sum of the CCA's charges plus the PCIA must be lower than PG&E's generation rate.

Mitigation: The PCIA is established at the CPUC. To ensure that this charge is properly calculated and that it is correctly allocated to Los Banos CCA customers, it will be necessary for a Los Banos CCA or PCE to monitor and possibly actively participate in the regulatory proceedings in which the CPUC sets the PCIA. We note that PCE is active, both alone and through CalCCA, in numerous CPUC proceedings.

CPUC "Financial Security Requirement" Risk

Pursuant to CPUC Decision 05-12-041, a new CCA must include in its registration packet evidence of insurance or bond that will cover such costs as potential re-entry fees, specifically, the cost to PG&E if the CCA were to suddenly fail and be forced to return all its customers back to PG&E bundled service. Currently, a bond amount for CCAs is set at $147,000.

This CCA bond amount covers PG&E's administrative cost to reintegrate a failed ESP's customers back into bundled service, plus any positive difference between market-based costs for PG&E to serve the unexpected load and PG&E's retail generation rates. Since the CCA bonding requirement has been in place, retail rates have always exceeded wholesale market prices, and thus CCAs' bond requirement has been simply the equal to a modest administrative cost.

Mitigation: During normal conditions, the CCA Bond amount will not be a concern. However, during a wholesale market price spike, the bond amount could potentially increase to millions of dollars. But the high bond amount would likely be only short term, until more stable market conditions prevailed. Also, it is important to note that high power prices (that would cause a high bond requirement) would also depress PG&E's PCIA and would also raise PG&E's rates, which would in turn likely provide the CCA sufficient headroom to handle the higher bonding requirement and keep its customers' overall costs competitive with what they would have paid had they remained with PG&E.

Direct Access and Competitive Retail Services

A possible important risk to PCE (and all CCAs) is the expansion of Direct Access (DA) eligibility.[33] The State currently limits the amount of load that may take this DA service. Currently, about 15% of the load in PG&E's territory is served through Direct Access, with an additional 3% likely to occur in late 2020 due to the limited expansion of the DA program provided for in Senate Bill 237. In addition to modestly expanding the availability of DA service, SB 237 also directed the CPUC to report to the Legislature by June 1 of 2020 on how to open DA completely for all non-residential customers. The CPUC's report on how to fully open DA service is still pending, but the legislation's direction is more how to fully open DA service, not if it should. A fully opened DA market would allow any commercial or industrial customer served by PCE to switch its provider to a third-party, potentially reducing PCE's revenue and creating a mismatch between its wholesale power portfolio and the CCA's load.

***Mitigation**:* A Los Banos CCA or PCE management must follow this issue closely and take appropriate steps, such as altering its procurement mix and strategies, when the Legislature and CPUC act.

Energy Risk Management

A CCA faces financial risk of procuring energy, capacity, Renewable Energy Credits, and carbon-free energy (if needed) at a cost that exceeds the revenue that it receives from its retail customers. The other risks that are faced by the CCA roll up into the overarching risk of buying products and operating the CCA at a cost that exceeds revenue. Those risks are listed below:

- Net Revenue
- Market Price
- Volume
- Temporal
- Basis
- Counterparty Credit
- Counterparty Performance
- Liquidity
- Operational

***Mitigation**:* The CCA must establish a sound risk management program that forms the structure for measuring, monitoring and managing risk. PCE's Risk Management plans can be found on its website.[34]

[33] Direct Access (DA) service is retail electric service where non-residential customers purchase electricity from a competitive provider called an Electric Service Provider (ESP), instead of from a regulated electric utility or CCE provider.

[34] https://www.peninsulacleanenergy.com/wp-content/uploads/2017/01/Policy-7-Revised_Adopted-022317.pdf

Legislative and Regulatory Risks

As noted above, the CCA must meet various procurement requirements established by the State and implemented by the CPUC or other agencies. Regulatory risk, which changes the rules under which CCAs operate, affects the CCA's ability to maintain stable procurement activities, manage costs to its customers, and compete with the local incumbent utility and direct access providers.

Regulation of the electric utility sector that affects CCAs at the federal level is provided by the Federal Energy Regulatory Commission (FERC) which regulates the CAISO and at the state level by the California Public Utilities Commission (CPUC) which implements legislation passed by the California State Legislature and signed into law by the governor. Although CCAs are not directly regulated by the CPUC but rather their own local governing bodies, the CPUC is tasked with implementing details of legislation signed into law. The California Air Resources Board (CARB) regulates emissions.

The risk to CCAs is in changes in the regulatory environment that affects the CCA's ability to attract, compete, and retain customers, products that it has already procured, and procurement practices going forward. Major issues that are currently evolving include:

- Direct Access
- Resource Adequacy
- Power Charge Indifference Adjustment
- Renewable Energy Purchase Requirement
- Power Content Label Reporting
- Central Procurement Entity
- Energy Provider of Last Resort (POLR)

These include procuring sufficient resource adequacy capacity of the proper type and meeting RPS requirements that are evolving.[35] Additional rules and requirements might be established. These could affect the bottom line of the CCA.

Mitigation: Regulatory and legislative risk can only be managed though close monitoring of the relevant proceedings at the CPUC and legislation in Sacramento and intervene where needed to advocate for the CCA. If Los Banos pursues CCA, it should consider teaming with other CCA, such as through the CalCCA trade organization on regulatory and legislative monitoring. As noted, PCE is already active at the CPUC and participating in CalCCA.

Political Risk

Any major decision made by the City Council carries with it political risk. If the CCA goes well, it could go unnoticed by most residents and businesses. If things go upside down, the blame and accountability could be directed at the elected officials. Fortunately, we have not seen this occur.

[35] Rules to establish RPS requirements under the new 50% RPS mandate are currently being debated at the CPUC.

Chapter 6. Governance Options

This study focused on the implications of Los Banos joining PCE. That is not its only option. The City has two primary options available for CCA:

1. Where the City is the sole government agency responsible for the CCA's creation and operation,
2. Joining an existing CCA JPA.

Forming a Single City Agency

In a sole jurisdiction approach, the City maintains full flexibility—and responsibility—for developing policies and procedures. This means that it can be tailored to and responsive to the City's stakeholders and constituents only and based upon their own objectives. The City would be responsible for setting policy priorities in general and making specific decisions about power generation, staffing policies, local economic development activities and strategies, and financial and debt policies. Along with greater autonomy, the City would assume all risk, liability, and costs associated with operating the CCA. In this case, the likely path would be for the City to establish the CCA as an enterprise fund, and work with appropriate legal counsel to explore options for controls and structural safeguards to insulate it and minimize risk to the City's general fund.

Enterprises are commonly used for public utilities such as electric, water and wastewater, or other city functions where a public service is operated and provided in a manner similar to a business enterprise, where fees and charges are collected for services provided, and accounting and budgeting are separate from a city's general fund. Establishing an enterprise fund provides management and CCA customers with more visibility and accountability, and the ability to more easily separate and measure performance, analyze the impact of management decisions, determine the cost of providing electric service, and use this information to develop cost-of-service electric rates. Enterprise accounting will allow the City to demonstrate to customers, the public, and other stakeholders that the cost of power is being recovered through its rates, and not being subsidized or comingled with other City funds or functions.

Within the city-only option, the Los Banos CCA would determine if it is to be a fully in-house operation with existing or added City Staff, or if the City would outsource some or all of the activities, with the City only administering contracts and managing vendors. Examples of some of the categories of operating activities that would need to be performed in-house or outsourced include:

- Power procurement, scheduling
- Finance, budgeting, and accounting
- Coordinating with PG&E on billing
- Customer service
- Communications, outreach and public relations

- Specific programs such as demand response, EE, EV or rooftop solar PV
- Regulatory monitoring and compliance, CPUC filings, etc.

Forming its own CCA would also require a significant outlay of City funds. Before operation, Los Banos would have to commit $500,000 to $1,000,000 to get the CCA off the ground. Ideally, this would be a loan to the CCA, which would be paid off through rate revenue during the first few years of operation. Furthermore, the CCA's financial services provider (i.e., bank) could require the City to backstop the CCA with a letter of credit, which could place a liability on the City's books and negatively impact the City's credit position.

While this study did not quantitively consider a Los Banos-only CCA, a few conclusions can still be reached. First, it is not likely that a stand-alone Los Banos CCA could offer rates lower than PG&E in 2022 and perhaps even 2023. After that, the PCIA is expected to markedly decrease along with the costs associated with procuring local RA. The combination of these two factors could make a Los Banos-only CCA feasible in 2023 or 2024.

Joining an Existing JPA (PCE)

The second option would be to join an existing CCA JPA, such as PCE. A JPA is an independent agency that operates on behalf of the public agencies which are party to its creation. In this approach, the City effectively shares responsibility with the other agencies participating in the JPA. The divisions of these responsibilities and the sharing of decision-making authority are based on the existing JPA's formation documents.

With respect to governance, the PCE board has two directors appointed by the San Mateo County Board of Supervisors and one director appointed by each City or Town that becomes a party to the JPA.[36] If Los Banos were to join, it would be the 21st municipal jurisdiction and thus have one out of 23 board members. In general, decisions are made by a majority vote of the directors' present at the meeting. However, any director can request an additional weighted vote by vote share. Each director has a voting share determined by the percent of energy their party uses out of the total energy for the CCA for that effective year. If a party has more than one director, then the voting shares allocated to the entity shall be equally divided amongst its directors. There are also special cases for involuntary termination of a party which require a 2/3 vote and for a decision to exercise the power of eminent domain which requires a 75% majority vote.

A JPA structure also reduces the risks of CCA participation by immunizing the financial assets of the City and the other agencies participating in the CCA. The CCA's debts are its own, and creditors cannot come to the City for any recourse.

A CCA operated under a JPA could benefit from increased negotiating and buying power for power purchases, access to better financing terms for borrowing, and operating efficiencies gained by combining back-office functions such as billing and accounting. These benefits would

[36] http://file.lacounty.gov/SDSInter/green/1006202_PeninsulaCleanEnergyAuthorityJointPowersAgreement.pdf, (JPA) p.4

accrue to customers through better pricing for power and debt, and ultimately more competitive electric rates. A larger JPA could also wield more political influence, which could be beneficial when participating in CPUC or other regional or state regulatory, legislative, or policy making activities.

Key tradeoffs to the benefits of a JPA are that decision making is allocated amongst the parties and management independence is diminished. Objectives of participating agencies could differ, and reduced autonomy can manifest when setting priorities for local generation, economic development activities, and importance of support programs. In the case of PCE, Los Banos should consider how or if PCE's priorities match its own. For example, PCE is committed to 100% renewable power by 2025, which includes the output of the Wright Solar Project located in Los Banos. A CCA with a less aggressive renewable policy could potentially offer lower rates.

Requirements per CPUC Resolution 4907

CPUC Resolution E-4907 establishes the schedule for creation of a new CCA or expansion of an existing one. This process is outlined in Table 16.

Table 14. CCA Implementation Schedule Per CPUC Resolution 4907

Date	Action
Day 1, Year 1 (On or before January 1 Year 1)	(1) The prospective or expanding CCA submits its Implementation Plan to Energy Division and serves it on selected docket service lists
Day 1 – 10, Year 1	(1) The CPUC notifies the Utility servicing the customers that are proposed for aggregation that an implementation plan initiating their CCA program has been filed.
Day 1 – 60, Year 1	(1) The CCA provides a draft customer notice to CPUC's Public advisor. (2) Within 15 days of receipt of the draft notice, the Public Advisor shall finalize that notice and send it to the CCA.
DAY 1 – 90, Year 1	(1) The CPUC sends a letter confirming that it has received the Implementation Plan and certifying that the CCA has satisfied the requirements of Section 366.2(c) (3). (2) The CPUC provides the CCA with its findings regarding any cost recovery that must be paid by customers of the CCA in order to prevent cost shifting. (P.U. Code Section 366.2 (c) (7).) (3) The CCA and the Utility should Meet-and-Confer regarding the CCA's ability to conform its operations to the Utility's tariff requirements.
DAY 1 – 90, Year 1	(1) The CCA submits its registration packet to the CPUC, including: a. Signed service agreement with the utility, b. CCA interim bond of $100,000 or as determined in R.03-10-003
Day 90 – 120, Year 1	(1) If the registration packet is complete, the CPUC confirms Registration as a CCA.
April, Year 1	(1) The CCA submits its year ahead Resource Adequacy forecast (P.U. Code Section 380)
August, Year 1	(1) The CCA submits its updated year-ahead RA forecast
October Year 1 (75 days before service commences)	(1) CCAs submit their Monthly load migration forecast for the Resource Adequacy program, filed about 75 days prior to the compliance month.
Within 60 days of the CCA's Commencement of Customer Automatic Enrollment	(1) The CCA shall send its first opt-out notice.
Within 30 days of the CCA's Commencement of Customer Automatic Enrollment	(1) The CCA shall send a second opt-out notice. (2) Once notified of a CCA program, the Utility shall transfer all applicable accounts to the new supplier
January 1, Year 2	(1) CCA begins service.

Appendix: Detailed Pro Forma Outputs