Attachment A

# North San Diego County Cities, California

## Community Choice Energy
## Technical Feasibility Study

**Prepared for:**
**The Cities of Carlsbad, Del Mar,**
**Encinitas and Oceanside**

**March 28, 2019**

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EES Consulting, Inc.

March 28, 2019

Ms. Crystal Najera
City of Encinitas
505 South Vulcan Avenue
Encinitas, CA 92024

SUBJECT: Draft CCE Technical Feasibility Study

Dear Ms. Najera:

Please find attached the Final Community Choice Energy Technical Feasibility Study (Study) for the cities of Carlsbad, Del Mar, Encinitas and Oceanside (Partners).

It has been a pleasure working for these Partners and we very much appreciate all the effort this working team has spent on the Study.

Very truly yours,

Gary S. Saleba

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# Executive Summary

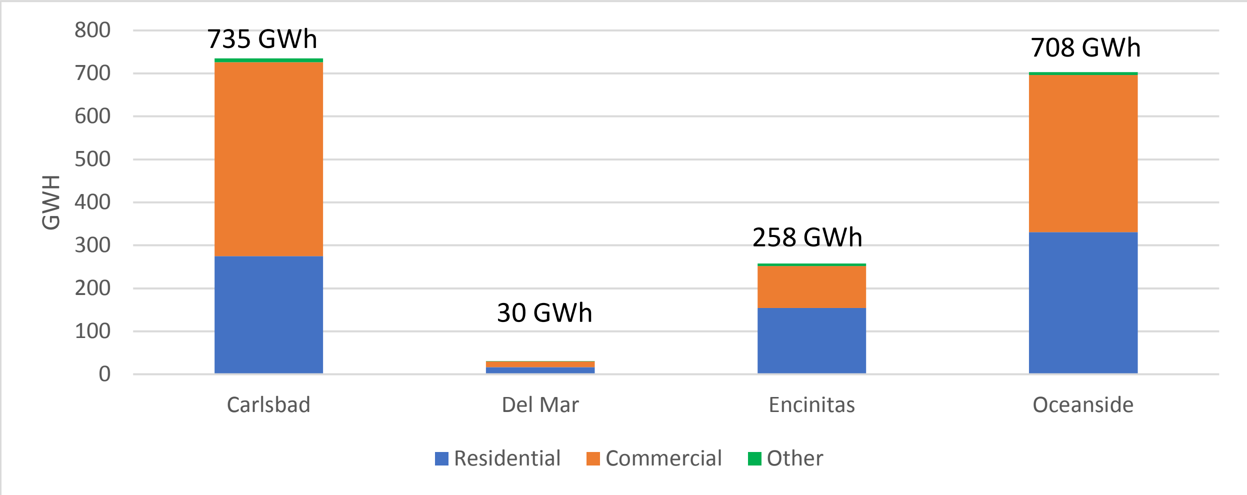
## Introduction

California Assembly Bill 117 allows local governments to form Community Choice Aggregations (CCAs), which are also referred to as Community Choice Energy (CCE) programs, that offer an alternative electric power option to constituents currently served electric power by investor owned utilities (IOUs). Under the CCE model, local governments purchase and manage their community's electric power supply by sourcing power from a preferred mix of traditional and renewable generation sources, while the incumbent IOU continues to provide distribution service. CCEs face the same requirements for renewable energy purchases as the incumbent IOUs and public utilities; however, many CCE programs can offer power content that has a greater share of renewable energy compared with the incumbent utility and at lower retail rates. This Technical Feasibility Study (Study) evaluates the financial feasibility of a potential CCE for the cities of Carlsbad, Del Mar, Encinitas and Oceanside (Partners).

## Electric Load

Exhibit ES-1 shows the amount of energy consumed in each of the Partner cities in 2017. Carlsbad and Oceanside have the highest consumption. Residential and commercial customers make up the majority of energy use across all cities. The Other category includes street lighting and agriculture. [1]

**Exhibit ES-1**
**2017 Load by City[2]**




[1] The Commercial category includes all commercial customers plus industrial customers.

[2] 1 Gigawatt hour (GWh) is 1 million kilowatt-hours. The typical California home uses 600 kWh/month.

Exhibit ES-2 summarizes the CCE costs for the first nine months of operation assuming customers begin taking service in April 2021. This exhibit assumes the percent of power supply obtained from renewable resources for the Partner cities would be equal to SDG&E's current levels. The operational and administrative costs for the CCE are estimated based on costs incurred by other CCEs launched in California in recent years. Operational and administrative costs may vary depending on the proportion of staff internal to the CCE versus contracted as consulting services. Typically, California CCEs have kept internal staffing to a minimum and relied on consultants with expertise in energy procurement to manage the more technical components of the CCE. Debt service payments are included and are needed to pay back loans needed to provide start-up capital and initial operations working capital.

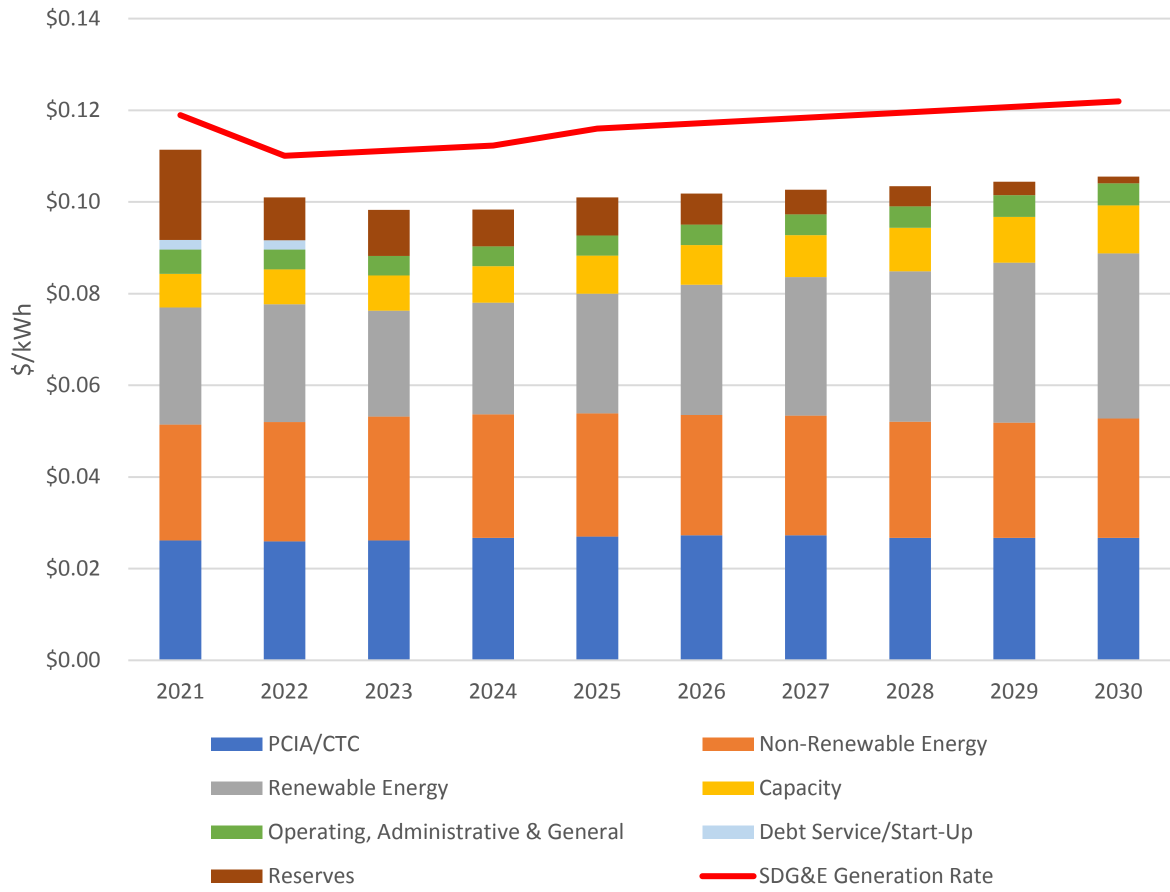
**Exhibit ES-2**
**2021 CCA Costs, SDG&E-Equivalent Renewable Portfolio**
**Base Case Renewable Pricing**
**$Millions**

| | |
|---|---|
| Cost of Energy | $71.3[1] |
| *Operating & Administrative* | |
| Billing & Data Management | $1.7 |
| SDG&E Fees | $0.4 |
| SDG&E Setup and Start-up Fees | $0.2 |
| Consulting Services | $1.6 |
| Staffing | $2.2 |
| General & Administrative Expenses | $0.2 |
| Debt Service | $2.5 |
| Total O&A Costs | $8.8 |
| **Total Cost** | $80.1 |

1. Conservatively includes mostly short-term renewable contract prices as described in the Power Supply Strategy and Cost section of this Study.

Exhibit ES-3 illustrates the 10-year financial forecast for the CCE to provide a power supply mix with a renewable power content equal to SDG&E's renewable power content forecast (SDG&E-Equivalent Renewable Portfolio scenario). Because that chart is only for power supply costs, it does not provide the overall impact to customer rates. The rates faced by the customer include the distribution component provided by the IOU in addition to the power supply component provided by the CCE. When the full customer bill is considered, and under the base assumptions, the CCE is able to provide an approximate 2% overall bill reduction to CCE customers. In addition, the CCE would build reserve funds that could be used for local programs or additional rate reductions. Each rate component illustrated in Exhibit ES-3 is described below the chart.

**Exhibit ES-3**
**Rate Comparison – CCE with SDG&E-Equivalent Renewable Portfolio**




**PCIA/CTC** - The PCIA/CTC (Power Charge Indifferent Adjustment/Competition Transition Charge) is included in ES-3 so that CCE rate may be compared directly with SDG&E generation rate.[3] The PCIA/CTC rates are the exit fees paid by all departing load customers (CCE customers and direct access) to compensate SDG&E for stranded energy and future generation costs they invested in on behalf of customers who leave SDG&E service for CCE service. The exit fee ensures that customers remaining with SDG&E do not pay for any costs incurred as a result of CCE customers leaving SDG&E. While the CCE would not directly pay these costs, CCE customers would pay them on their electric bills; therefore, they are included in the comparison above.

**Non-renewable Energy** – Non-renewable Energy costs include the cost of power for non-renewable resources used to meet CCE load requirements. The cost to meet greenhouse gas free targets is also included in this category. For the SDG&E-Equivalent Renewable Portfolio,

[3] Power Cost Indifference Adjustment, or PCIA, plus the competition transition charge, CTC.

resources are 80% GHG free and cost CCE ratepayers an average additional $0.0014/kWh. This adder is based on forecast prices for GHG free energy starting at $0.004/kWh in 2021.

**Renewable Energy** – Renewable energy costs include both the energy component and the renewable attributes. These costs increase over the study period as a higher share of renewable energy is purchased to meet both RPS and SDG&E's projected renewable portfolio. The base case renewable contract prices included in the Study are based on two conservative assumptions: 1) the majority of renewable energy purchases are made at short-term, rather than long-term, renewable contract prices and 2) the long-term renewable contract price is greater than the price at which existing CCEs are currently transacting. An alternative scenario is included in the Study in which the renewable energy contract prices are less conservative and more accurately reflect the renewable resource portfolio of a functioning CCE.

**Capacity** – In addition to energy purchases, the CCE will need to purchase capacity and reserves to meet reliability and resource adequacy requirements as required by the CPUC and California Independent System Operator (CAISO). These costs are forecast to increase over the study period.

**Operating, Administrative & General** – Expenses required to operate the program as detailed in ES-2. These expenses are escalated at the inflation rate of 2%.

**Debt Service/Start-Up** – Repayment of start-up costs plus working capital requirements. The repayment term is 5 years; however, the analysis shows that start-up costs can be repaid within 3 years.

**Reserves** – Cash reserves equal to 120 days of operating expenses are held to ensure the CCE can operate in a changing environment. Reserves are often used as a rate stabilization measure during periods of market instability. Reserve targets are calculated over the study period and the reserve level increases as power supply costs and operating expenses escalate.

**SDG&E Generation Rate** – The SDG&E generation rate is forecast to increase at a conservative level of 1% annually. This escalation rate is conservative considering SDG&E generation rates have increased as much as 2-9% over the period 2006 to 2015.[4] The basis for the generation rate forecast includes future expectations about renewable energy costs, non-renewable costs, and RPS requirements. While costs for non-renewable resources (wholesale market prices) and resource adequacy are expected to increase; renewable energy costs are expected to decline. If the SDG&E generation rate increases at a rate greater than 1% annually, the CCE's financial position would improve.

[4] Average annual generation rate increases for small commercial and small agriculture are 2%, large commercial is 4.7% and residential is 9.7% over the period 2006 to 2015. Estimated based on average weighting of summer and winter rates.

**Renewable Energy Portfolio Scenarios**

While Exhibit ES-3 shows the results for one power supply scenario, the Study analyzed the CCE rate under several different scenarios for renewable power content in the power supply mix. The three scenarios are described below. The first scenario (SDG&E-Equivalent Renewables Portfolio) was used above in Exhibit ES-3.

1) SDG&E-Equivalent Renewable Portfolio: Achieves between 46% and 59% of power supply from Renewable Portfolio Standard (RPS)-qualifying resources in 2021 through 2029, based on SDG&E planned renewable energy procurements. Achieves 60% RPS beginning in 2030.
2) 100% Renewable by 2030 Portfolio: 50% of retail loads are served with RPS-qualifying beginning in 2021 ramping up to 50% in 2025, 75% in 2029, and 100% in 2030 and after.[5]
3) 100% Renewables Portfolio: 100% of retail loads are served with RPS-qualifying renewable resources in all years.[6]

At a minimum, the CCE would need to meet State mandated Renewable Power Supply (RPS) requirements; however, since SDG&E will likely have higher renewable content than the RPS requires, this minimum requirement scenario was not analyzed in the study. It was assumed that the CCE would have a power supply mix with a renewable content that was at least equivalent to SDG&E. This portfolio is the base case scenario.

## Sensitivity Analysis

In addition to the base assumptions, uncertainties which could impact CCE rates were evaluated under different assumptions. Uncertainties analyzed included: higher or lower PCIA costs, higher market power costs, lower loads served by the CCE, higher loads served by the CCE, Exhibit ES-4 shows the results of the sensitivity analysis; in most cases, the CCE could continue to offer rate discounts. In the cases where high power costs result in CCE rates greater than SDG&E rates, the impact could likely be mitigated by offsets in both the PCIA and SDG&E generation rates.[7]

[5] Meets Climate Action Plan goals established by the cities of Encinitas (100% renewable by 2030) and Del Mar (100% renewable by 2035).

[6] Meets Climate Action Plan goals established by the cities of Encinitas (100% renewable by 2030) and Del Mar (100% renewable by 2035).

[7] Higher power supply costs would likely impact SDG&E at the same time as the CCE. Therefore, higher CCE power costs would be mitigated by both lower PCIA rates and a higher SDG&E generation rate.

| Exhibit ES-4<br>Partner CCE Rate Sensitivity<br>10-Year Levelized Rate and Average Discount 2021-2030[1] | | | | | | |
|---|---|---|---|---|---|---|
| | SDG&E-Equivalent Renewable Portfolio | | 100% Renewable by 2030 | | 100% Renewable | |
| **Sensitivity** | **$/kWh** | **Rate Discount** | **$/kWh** | **Rate Discount** | **$/kWh** | **Rate Discount** |
| Base Assumptions | $0.2927 | 2% | $0.2927 | 2% | $0.2987 | 0% |
| High PCIA | $0.2989 | 0% | $0.2989 | 0% | $0.3050 | -2% |
| Low PCIA | $0.2901 | 3% | $0.2901 | 3% | $0.2960 | 1% |
| High Power Costs[2] | $0.3136 | -5% | $0.3170 | -6% | $0.3180 | -7% |
| Low Load | $0.2931 | 2% | $0.2931 | 2% | $0.2991 | 0% |
| High Load | $0.2920 | 2% | $0. 2989 | 0% | $0.2980 | 0% |

[1]Negative rate discounts indicate that the CCE retail rate is higher than the SDG&E bundled rate.

[2]The CCE purchases power supply at costs higher than SDG&E.

## Findings and Conclusions

Based on the analysis conducted in this Study, the following findings and conclusions are made:

- The formation of a CCE is financially feasible and could yield considerable benefits for all participating residents and businesses.
- Financial benefits include electric retail rates that are 2% lower compared with SDG&E rates
- Other benefits include local control over power supply sources, rate levels and customer programs. Specific programs such as economic development incentives, and targeted energy efficiency and demand response programs could be implemented.
- CCE start-up costs could be fully recovered within the first three years of CCE operations.
- After this cost recovery, revenues that exceed costs could be used to finance a rate stabilization fund, new local renewable resources, economic development projects and/or lower customer electric rates.
- The sensitivity analysis shows that the ranges of prices for different market conditions will, in most cases, not negatively impact CCE rates compared to SDG&E rates. Where negative impacts may exist, those risks can be mitigated.
- The CCE could be a means to achieve local control of energy supply and for cities to meet their respective Climate Action Plan (CAP) goals.
- Local electric rate savings are expected to stimulate economic development for the Partner cities.

The positive impacts on the Partner cities and their citizens of forming a CCE suggest that CCE implementation should be considered with the following next steps: consideration of Joint Powers Authority or other governance options, Business Plan development, and Implementation Plan development. No likely combination of sensitivities would change this recommendation based on the detailed analysis contained in the balance of this report.

# Introduction

California Assembly Bill 117 allows local governments to form Community Choice Aggregations (CCAs), which are also referred to as Community Choice Energy (CCE) programs, that offer an alternative electric power option to constituents currently served electric power by investor owned utilities (IOUs). Under the CCE model, local governments purchase and manage their community's electric power supply by sourcing power from a preferred mix of traditional and renewable generation sources, while the incumbent IOU continues to provide distribution service. CCEs face the same requirements for renewable energy purchases as the incumbent IOU and other public utilities; however, many CCE programs can offer power content that has a greater share of renewable energy compared with the incumbent utility and at lower retail rates. This Technical Feasibility Study (Study) evaluates the financial feasibility of a potential CCE for the cities of Carlsbad, Del Mar, Encinitas and Oceanside (Partners).

While a CCE financial feasibility study typically focuses purely on the logistical and financial feasibility of operating a CCE, this Study also includes a discussion of governance and organizational alternatives.

As the IOU currently providing electric power to the Partners, San Diego Gas and Electric (SDG&E) was asked to provide historic energy use data for the Partners' service areas. Using the information provided by SDG&E, EES Consulting, Inc. (EES) estimated future power supply costs, administrative costs, electric loads, and retail rates under various Partner CCE scenarios, and for SDG&E service. These forecast rates were then compared to determine if the CCE could feasibly offer competitive rates, service and lower greenhouse gas options.

The Study assumes that a CCE created among the Partner cities would directly support the cities' Climate Action Plans (CAPs), and would generally aspire to meet the following objectives:

- Decrease greenhouse gas (GHG) emissions from electricity generation
- Increase the renewable energy in the power mix to exceed the baseline power mix offered by SDG&E, including the 100% Clean Energy goals set by the Del Mar and Encinitas CAPs
- Provide competitive rates
- Provide local control over rate setting
- Provide customer choice to residents and businesses
- Reinvestment of residual revenue in local renewable power initiatives
- Promote and incentivize community-focused CCE programs

While the Partners have not yet officially adopted these goals, they serve as the foundation for this Study. Once the Partners' goals are refined, adopted, and prioritized, modifications to this Study may be appropriate.

## Study Methodology

This Study evaluates the estimated costs and resulting rates of operating a CCE for the Partners and compares these rates to a SDG&E rate forecast for the years 2021 through 2030. This pro forma financial analysis models the following cost components:

- Power Supply Costs:
  - Wholesale purchases
  - Renewable purchases
  - Procurement of resource adequacy (RA) capacity (System, Local and Flexible capacity products)
  - Other power supply and charges
- Non-Power Supply Costs:
  - Start-up costs
  - CCE staffing and administration costs
  - Consulting support
  - SDG&E and regulatory charges
  - Financing costs
- Pass-Through Charges from SDG&E:
  - Transmission and distribution charges
  - Power Charge Indifference Adjustment (PCIA)

The information above is used to determine the projected retail rates for the CCE. The CCE rates are then compared to the SDG&E projected rates for the Partners' CCE service area. After these rate comparisons are made, the attendant economic development and greenhouse gas (GHG) comparisons are made. Operational and governance options are discussed, as well as a sensitivity analysis of the key variables contained in the Study.

## Study Organization

This Study is organized into the following main sections:

- Load Requirements
- Power Supply Strategy and Costs
- Partners' CCE Cost of Service
- Product, Service and Rate Comparisons
- Environmental/Economic Considerations
- Sensitivity Analysis
- CCE Governance
- Conclusions and Recommendations

# Load Requirements

One indicator of the viability of a CCE for the Partners is the number of customers that participate in the CCE as well as the quantity and timing of energy these customers consume. This section of the Study provides an overview of these projected values and the methodology used to estimate them.

## Historical Consumption

SDG&E provided hourly historical data on energy use (kWh) for customers receiving power supply services from SDG&E (bundled customers) in each of the four cities for the 2017 calendar year. Bundled customers currently purchase the electric power, transmission and distribution from SDG&E. Direct Access (DA) customers buy only the transmission and distribution service from SDG&E and purchase power from an independent and competitive Electric Service Provider (ESP). In California, eligibility for DA enrollment is currently limited to non-residential customers and subject to a maximum allowable annual limit for new enrollment measured in gigawatt-hours of new load and managed through an annual lottery.[8] Customers classified as taking service under DA arrangements are not included in this Study, as it is assumed that these customers would remain with their current Energy Service Provider (ESP)[9]. Once operating, the CCE may decide to provide service options to DA customers with expired contracts, but our approach offers the most conservative analysis of feasibility.

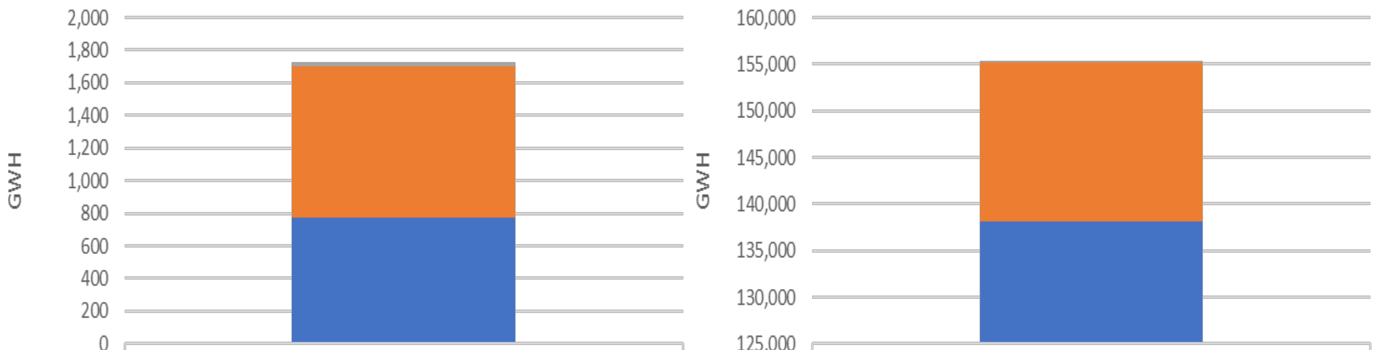
EES aggregated this data by rate class in each month for bundled (full service) customers. In total, bundled residents and businesses within the four cities purchased 1,722 GWh of electricity in 2017 from SDG&E.

Exhibit 1 summarizes energy consumption and number of accounts for bundled customers in 2017.

[8] S.B. 286 (CA, 2015-2016 Reg. Sess.)

[9] CPUC rulemaking to date has not addressed how vintage would be handled to DA customers that opt to switch to receive electric power from a CCA rather than their ESP. The most recent ruling on PCIA vintaging was issued on 10/5/2016: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M167/K744/167744142.PDF.

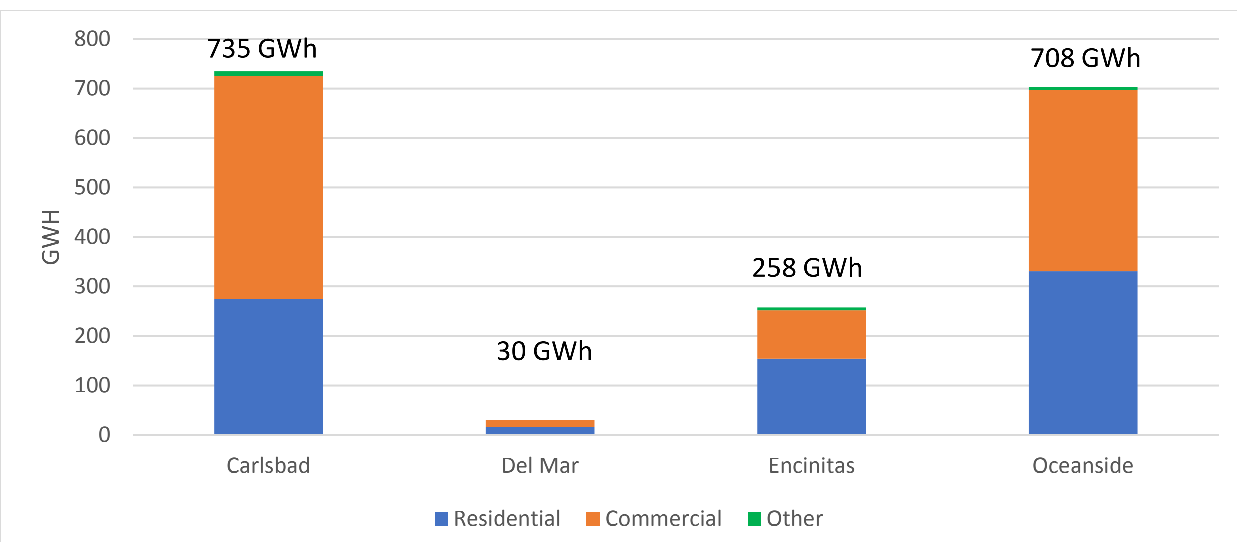
**Exhibit 1**
**Bundled Load and Accounts in 2017 (Four Cities)**




| | Load | Customers |
|---|---|---|
| Other | 21 | 181 |
| Commercial | 927 | 17,044 |
| Residential | 777 | 138,078 |
| | Total 1,725 GWH | Total 155,303 |

Exhibit 2 shows the amount of energy consumed in each of the Partner cities in 2017. Carlsbad and Oceanside have the highest consumption while residential and medium/large commercial[10] and industrial customers make up the majority of energy use across all cities.

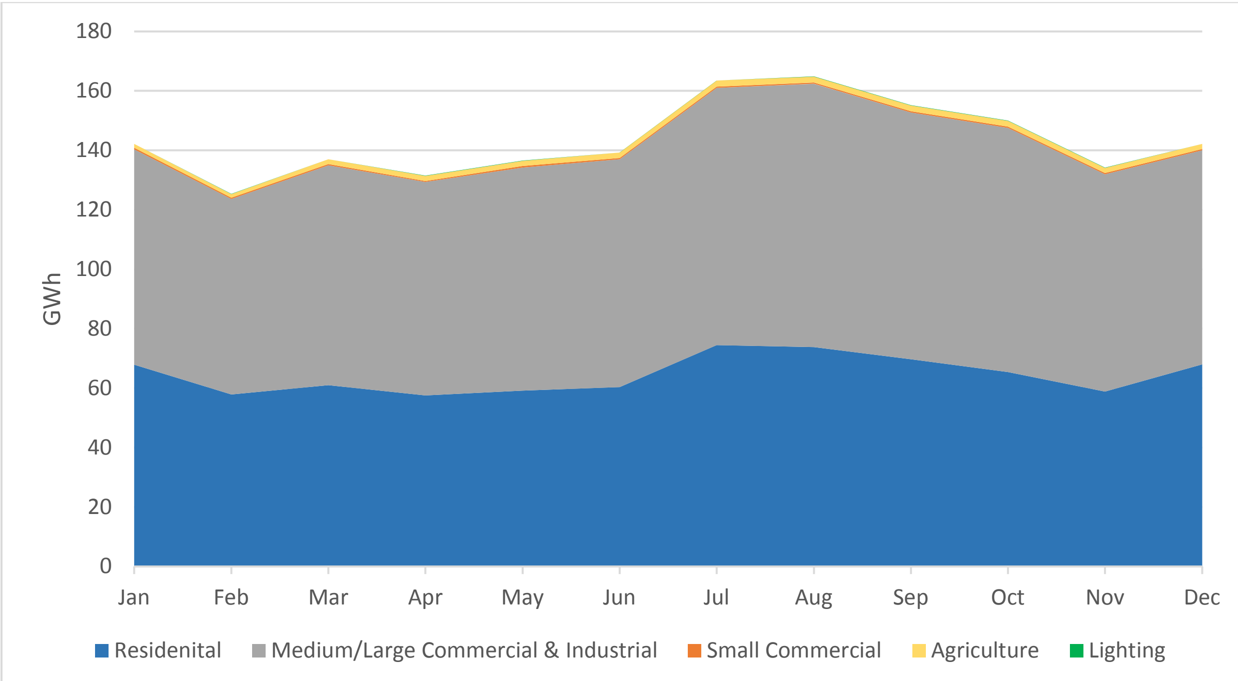
**Exhibit 2**
**2017 Load by City**




[10] A small commercial customer would typically be a convenient store or smaller office building, while a medium/large commercial customer would for example be a grocery store.

Monthly historic load from 2017 is shown in Exhibit 3.

**Exhibit 3**
**2017 Monthly Aggregated Load**




## CCE Participation and Opt-Out Rates

Before customers are served by a CCE, they receive two notices with their monthly energy bills 60 days and 30 days before the CCE's launch, and another two notices 30 days and 60 days after the CCE launches. These notices provide information needed to understand the terms and conditions of service from the CCE and explain how customers can opt-out, if desired. Notices typically provide a rate comparison between the CCE and the IOU. All customers that do not follow the opt-out process specified in the customer notices prior to launch would be automatically enrolled into the CCE.[11]

As such, the Partners' CCE would provide a minimum of four opt-out notices to customers to notify and educate them about the CCE's product offerings and their option to opt-out. Customers automatically enrolled would continue to have their electric meters read and billed for electric service by SDG&E. The Partners' CCE bills processed by SDG&E would show separate charges for power supply procured by the CCE, all other charges related to delivery of the electricity by SDG&E and other utility charges that would continue to be assessed.

[11] Typically, this doesn't apply to DA customers as the CCA would assume that these customers are not interested in being served by the CCA unless otherwise confirmed prior to launching service.

This Study anticipates an overall customer participation rate of 85% for the Commercial and Industrial accounts. For residential accounts, it is assumed that approximately 95% of customers would remain with the Partners' CCE. For commercial and industrial accounts, the participation rate is 85% which adjusts historic participation rates for the new cap on direct access.[12] These participation assumptions are conservative based on participation rates in other CCEs, however, this Study's sensitivity analysis tested CCE feasibility under higher opt-out scenarios. Operating CCEs in California have experienced overall participation rates ranging from 83% (Marin Clean Energy) to 98% (Peninsula Clean Energy). On average, 90% of all potential customers have stayed with their CCE.[13]

## Conceptual CCE Launch

The California Public Utilities Commission (CPUC) recently issued Resolution 4723, which requires that new CCEs file their Implementation plan by January 1, resulting in the earliest possible Partner CCE launch date of January 1 the subsequent year. Under this new requirement, the Partners' earliest possible launch date is early 2021. This Study assumes that service would be offered to all customers by April 2021 in one phase, at launch, as outlined in Exhibit 4.

**Exhibit 4**
**CCE Load, Customers, and Revenue**

| Assumed Start | Eligibility | Average Customer Accounts | Total Retail Load (GWh) | Peak Demand (MW) | Normalized Annual Operating Revenues to the CCE |
|---|---|---|---|---|---|
| Apr 2021 | All Customers | 145,500 | 1,138 | 322 | $120 million |

This launch strategy, without phasing, would enable the Partners' CCE to provide service to all customers as soon as possible. The number of customers and projected total load is similar to the number of customers enrolled by other CCEs launching in a single phase.[14]

[12] Opt-out rates were increased to account for a 16% increase in the amount of non-residential load that is allowed to move to direct access schedules. California Senate Bill 237: September 20, 2018. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB237

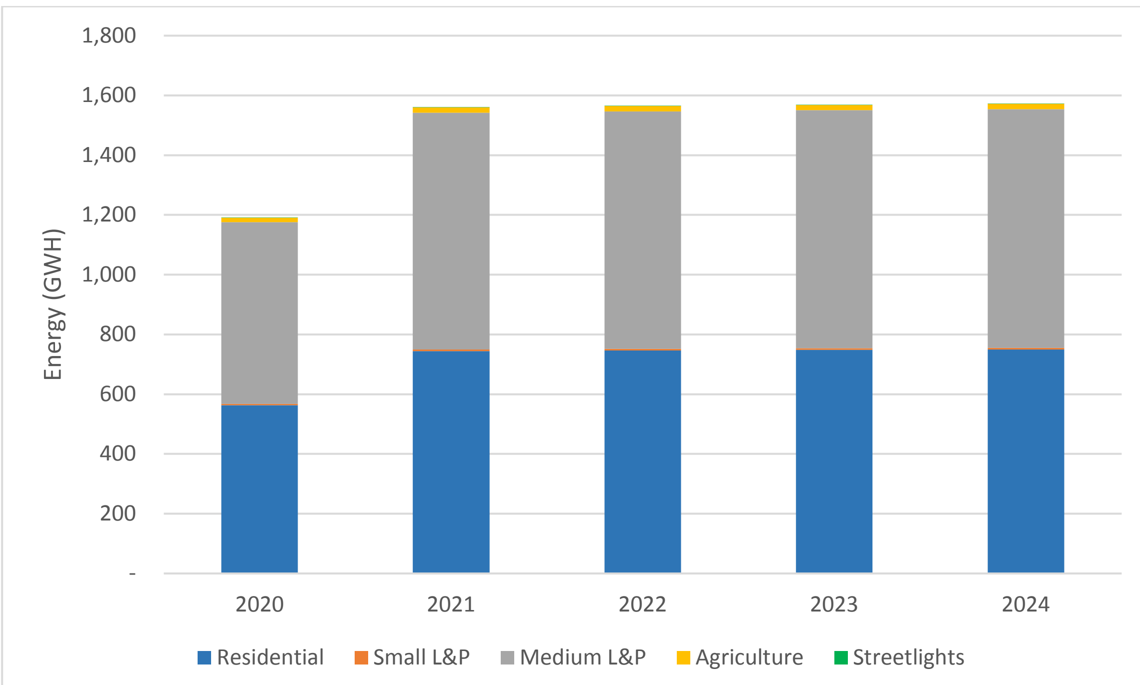
[13] Average opt-out rate determined based on published number of customers and opt-out rates of Marin Clean Energy, Peninsula Clean Energy, Sonoma Clean Power, Apple Valley Clean Energy, and Lancaster as found at the following document http://www.vvdailypress.com/news/20170818/apple-valley-choice-energy-prompts-thousands-of-customer-calls. Published 8/18/2017; accessed 2/15/2018.

[14] For example, Silicon Valley Clean Energy enrolled 180,000 residential customers and Monterey Bay Clean Energy enrolled 235,000 residential customers at one time.

## Forecast Consumption and Customers

The number of customers enrolled in the CCE and the retail energy they consume are assumed to increase at 0.25% per year. This forecast is selected as the midpoint based on the California Energy Commission's (CEC) mid-demand baseline forecasts for SDG&E service territory.[15] Peak demands are calculated using hourly consumption data provided by SDG&E. The forecast of load served by the Partners' CCE over the next five years is shown in Exhibit 5. The CCE forecast of GWh sales in Exhibit 6 reflects the single-phase roll-out and customer enrollment schedule discussed previously. Annual wholesale energy requirements are also shown below in Exhibit 6 ("Total Load" column).

**Exhibit 5**
**Projected Load by Sector (Four Cities)**




[15] http://www.energy.ca.gov/2017_energypolicy/documents/

| Exhibit 6<br>CCE Projected Annual Energy Requirements (GWh) | | | |
|---|---|---|---|
| **Year** | **Total Retail Sales** | **Losses[16]** | **Total Wholesale Load** |
| 2021 | 1,138 | 52 | 1,191 |
| 2022 | 1,561 | 72 | 1,633 |
| 2023 | 1,565 | 72 | 1,637 |
| 2024 | 1,569 | 72 | 1,641 |
| 2025 | 1,573 | 72 | 1,645 |
| 2026 | 1,577 | 73 | 1,649 |
| 2027 | 1,581 | 73 | 1,653 |
| 2028 | 1,585 | 73 | 1,658 |
| 2029 | 1,589 | 73 | 1,662 |
| 2030 | 1,553 | 71 | 1,625 |

[16]Transmission and Distribution power losses were estimated at 6.6% based on the California Energy Commission's Public Electricity and Natural Gas Demand Forecast published 4/20/2015 at http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN204261-9_20150420T154646_Pacific_Gas_and_Electric_Company's_Notes_re_2015_IEPR_Demand_Fo.pdf.

# Power Supply Strategy and Costs

This section of the Study discusses the CCE's resource strategy, projected power supply costs, and resource portfolios based on the Partners' CCE projected loads.

Long-term resource planning involves load forecasting and supply planning on a 10- to 20-year time horizon. Prior to launch, the Partners' CCE planners would develop integrated resource plans that meet their supply objectives and balance cost, risk, and environmental considerations. Integrated resource planning also considers demand side energy efficiency, demand response programs, and non-renewable supply options. The Partners' CCE would require staff or a consultant to oversee planning even if the day-to-day supply operations are contracted to third parties. This staff or consultant would ensure that local preferences regarding the future composition of supply and demand side resources are planned for, developed, and implemented.

## Resource Strategy

This Study assumes that the Partners' CCE would be interested in minimizing overall community energy bills, achieving GHG emissions reductions, stimulating local economic development to achieve CAP goals, and meeting or exceeding the State's renewable energy requirements. The CCE can likely achieve these goals within 5 years by taking advantage of relatively low wholesale market prices and abundant GHG-free energy. As discussed in greater detail below, the CCE's electric portfolio would be guided by the CCE's policymakers with input from its scheduling coordinator and other power supply experts. The scheduling coordinator would obtain sufficient resources each hour to serve all of the CCE customer loads. The CCE policymakers would guide the power supply acquisition philosophy to achieve the CCE's policy objectives.

## Projected Power Supply Costs

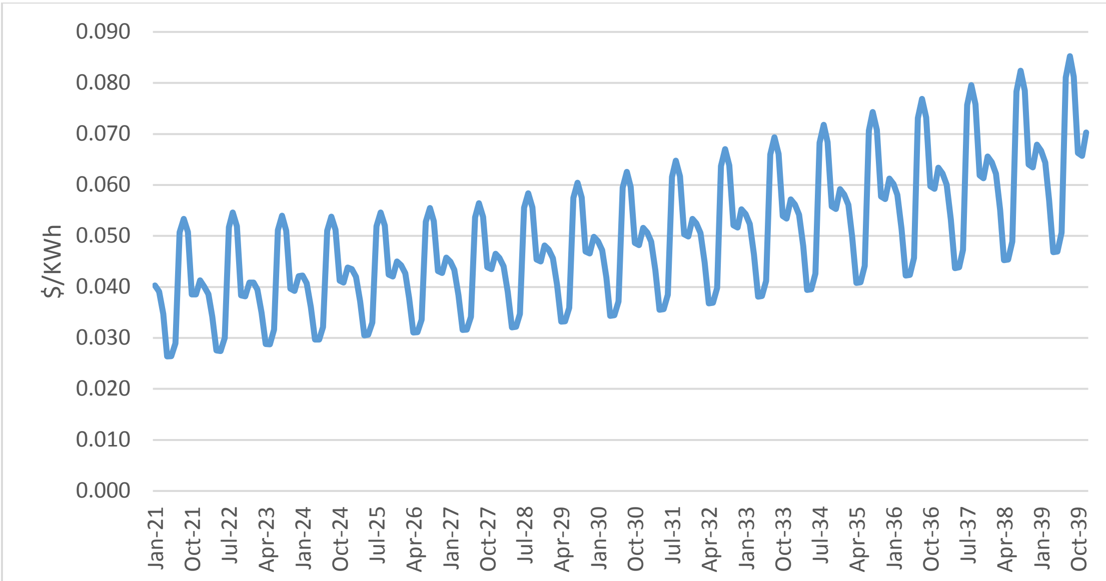
This Study presents the costs of renewable and non-renewable generating resources as well as power purchase agreements based on current and forecast wholesale market conditions, recently transacted power supply contracts, and a review of the applicable regulatory requirements. In summary, the CCE would need to procure market purchases, renewable purchases, ancillary services, resource adequacy, and power management/schedule coordinator services. The Study determines the base case assumption for each of these cost categories as well as establishing a high and low range for each to be used for the risk analysis later in the report.

### Market Purchases

Market prices for Southern California (referred to as SP15 prices) were provided by EES's subscription to a market price forecasting service, S&P Global. Exhibit 7 shows forecast monthly southern California wholesale electric market prices. The levelized value of market purchase prices over the 20-year Study period is $0.0471/kWh (2018$) assuming a 4% discount rate.

Exhibit 7 shows the clear seasonal variability in prices each year, as well as the overall trend in prices.

**Exhibit 7**
**Forecast Southern California Wholesale Market Prices**




Wholesale market power prices have been used to calculate balancing market purchases and sales. When the CCE's loads are greater than its resource capabilities, the CCE's scheduling coordinator would schedule balancing purchases. When the CCE's loads are less than its resource capabilities, the CCE's scheduling coordinator would transact balancing sales and the CCE would receive market sales revenue. Balancing market purchases and sales can be transacted on a monthly, daily and hourly basis, as needed.

**Renewable Energy**

The wholesale market prices shown above in Exhibit 7 are for non-renewable power (i.e., this product does not come with any renewable attributes). The cost of renewable resources varies greatly. Wind and solar levelized project costs vary from $0.035 to $0.060/kWh. Geothermal project costs can vary from $0.070 to $0.100/kWh. While geothermal projects have higher cost, they also have higher capacity factors than wind and solar projects and, as such, can bring additional value to the CCE as baseload resources. Geothermal resources also bring value from a resource adequacy perspective. The availability of off-shore wind and ocean power in the marketplace is fairly minimal, so these resources were not included in this assessment of renewable energy market prices.

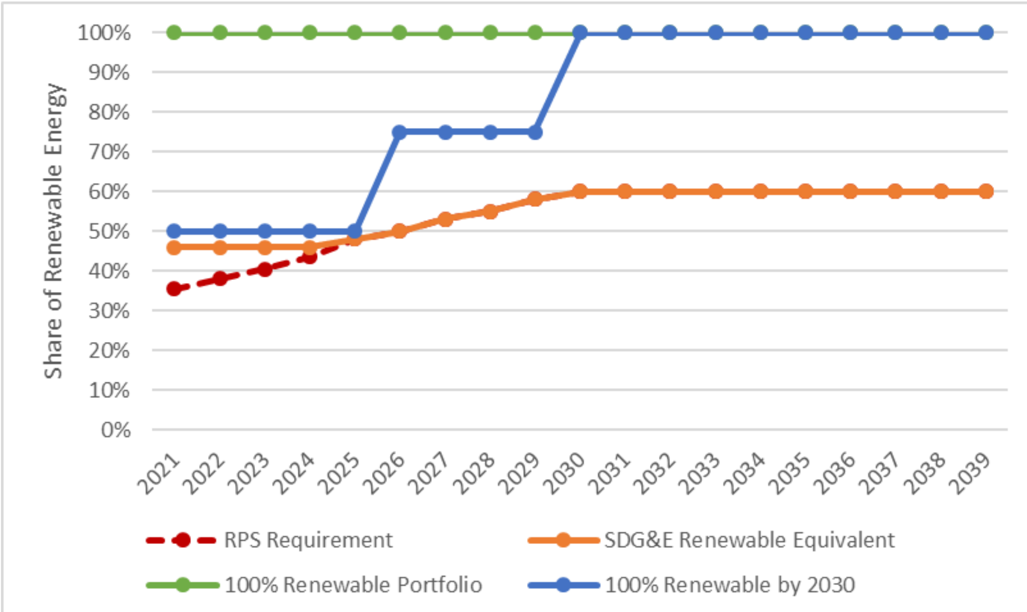
This Study assumes a Base Case renewable energy market price of $0.062/kWh for a blend of short-term and long-term wind and solar resource contracts, based on a survey of renewable resources currently in operation and new projects coming on-line. It is assumed that renewable energy contract prices will be stable for the 20-year Study period to balance the influence of two trends. First, renewable energy prices are being driven down by the rapidly declining cost of solar and wind projects. This trend has persisted over the past several years and is expected to continue over the Study's forecast period. However, this trend is expected to be balanced out by the impact of increasing statewide demand for renewables as a result of California's renewable portfolio standards (RPS) laws and changes in Federal tax laws. These assumptions regarding renewable energy prices have been independently confirmed by current market trends in southern California.

RPS compliance requirements are 50% in 2020 and growing again to 60% in 2030. But, at a minimum, comparability with SDG&E's renewable energy procurement plan is recommended. To provide information about the cost difference between renewable resource portfolios, this Study analyzes the following 3 portfolios:

1) **SDG&E-Equivalent Renewable Portfolio:** Achieve between 46% and 59% renewables in 2021 through 2029, based on SDG&E planned renewable energy procurements. Achieve 60% renewables beginning in 2030.
2) **100% Renewables by 2030 Portfolio:** 50% of retail loads are served with RPS-qualifying renewable resources through 2025, 75% through 2029, and 100% in 2030 and after.
3) **100% Renewables Portfolio**: 100% of retail loads are served with RPS-qualifying renewable resources in all years.

The resource portfolios will be discussed in greater detail in the "Resource Portfolios" section below. It should be noted that the CCE policymakers may opt for other resource portfolios but those selected above should give the Partners a sound basis for evaluating other resource portfolio options. The renewable energy targets of the three portfolios included in the power cost model are shown below in Exhibit 8. For comparison, the state RPS requirement is also presented in Exhibit 8. All power supply portfolios meet the RPS requirement (SB 100 and SB 350).

**Exhibit 8**
**Renewable Energy Purchase Scenarios Compared to the RPS Requirement**[17]




## Renewable Energy Credits (RECs)

In addition to direct purchases of renewable power, renewable energy credits (RECs) are an alternative for meeting RPS requirements. However, RECs are highly restricted and are not always the best alternative. California load serving entities (LSE)[18] must purchase bundled energy and/or RECs that meet certain eligibility requirements across three Portfolio Content Categories (PCC) or buckets. Each of the buckets represents a different type of renewable product that can be used to meet up to a specific percent of the total procurement obligation during a compliance period. The permitted percentage shares of each bucket type changes over time. The three buckets and the type of energy included in each bucket can be summarized as follows:

- **Bucket 1**: Bundled renewable resources and RECs – either from resources located in California or out-of-state renewable resources that can meet strict scheduling requirements ensuring deliverability to a California Balancing Authority (CBA);

[17] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M158/K845/158845742.PDF

[18] Load serving entities include entities that serve retail load, including IOUs, CCEs, and public utilities including municipal utilities.

- **Bucket 2**: Renewable resources that cannot be delivered into a CBA without some substitution from non-renewable resources[19]. This process of substitution is referred to as "firming and shaping" the energy. The firmed and shaped energy is bundled with RECs.

- **Bucket 3**: Unbundled RECs, which are sold separately from the electric energy.[20]

Under the current guidelines, the amount of RECs that can be procured through Buckets 2 and 3 is limited and decreases over time. SBX1 2 (April 2011) established a 33% RPS requirement for 2020 with certain procurement targets prior to 2020. SB350 (October 2015) increased the RPS requirement to 50% by 2030. The share of renewable power that can be sourced from Bucket 2 or 3 energy after 2020 is expected to be the same as the 2020 required share of total RPS procurement.[21] All power supply portfolios are modeled to meet the relevant state mandates. All load serving entities face the same mandates and resource choices.

Purchasing unbundled RECs from existing renewable resources does not increase the amount of renewable projects in the State. In addition, the REC market is not as liquid as it once was. For these reasons, this Study does not rely on unbundled REC purchases to meet renewable energy purchase requirements under the RPS.

However, in practice, small quantities of unbundled RECs may be used to balance the CCE's annual renewable energy purchase targets with the output from renewable resources. Due to the variable size and shape of the renewable energy purchases, the annual modeled renewable energy purchases do not typically match up perfectly with annual renewable energy purchase targets. In some years there are small REC surpluses, and, in others, there are small REC deficits. These surpluses and deficits can be balanced out using small unbundled REC purchases and sales. This methodology was used in order to simplify the modeling. In reality, small REC surpluses and deficits would most likely be handled by banking RECs between years. For the Base Case, unbundled REC prices are assumed to increase from $17.50/REC in 2020 to $29.09 in 2039 (2.7% annual escalation).

[19] This may occur if a California entity purchases a contract for renewable power from an out of state resource. When that resource cannot fulfill the contract, due to wind or sun intermittency for example, the missing power is compensated with non-renewable resources.

[20] For example, a small business with a solar panel has no RPS compliance obligation, so they use the power from the solar panel, but do not "retire" the REC generated by the solar panel. They can then sell the REC, even though they are not selling the energy associated with it.

[21] California Public Utilities Commission Final Decision, 12/20/2016, accessed at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K457/171457580.PDF, on 1/19/2017. 75% of the RPS procurement must be Bucket 1 resources and less than 10% of the RPS procurement can come from Bucket 3 resources.

**Ancillary Service Costs**

The CCE would need to pay the California Independent System Operator (CAISO) for transmission congestion and ancillary services associated with its power supply purchases. Transmission congestion occurs when there is insufficient capacity to meet the demands of all transmission customers. Congestion is managed by the CAISO by charging congestion charges in the day-ahead and real-time markets. The Grid Management Charge (GMC) is the vehicle through which the CAISO recovers its administrative and capital costs from the entities that utilize the CAISO's services.

In addition, because generation is delivered as it is produced and, particularly with respect to renewables, can be intermittent, deliveries need to be firmed using ancillary services to meet the CCE's load requirements. Ancillary services and products need to be purchased from the CAISO based on the CCE's total loads requirement. Based on a survey of transmission congestion and ancillary service costs currently paid by CAISO participants, the Partners' CCE Base Case ancillary service costs are estimated to be approximately $.003/kWh, escalating by 20% annually through the study period. Ancillary service costs are expected to increase significantly as California works toward the RPS requirements over the next 10 years.

**Resource Adequacy**

In addition to purchasing power, the CCE would also need to demonstrate it has sufficient physical power supply capacity to meet its projected peak demand plus a 15% planning reserve margin. This requirement is in accordance with RA regulations administered by the CPUC, CAISO and the CEC. In addition, the CCE must meet the local and flexible resource adequacy requirements set by the CPUC, CAISO and CEC every year.

The CPUC undertakes annual policy changes to the RA program, so these requirements may change by the time program launch occurs. Different types of resources have different capacity values for RA compliance purposes, and those values can change by month. Moreover, recent rule changes have reduced the RA values for wind and solar resources as more of these technologies are added to the system. As such, other types of renewables, including geothermal and biomass, could have an overall better value in the portfolio compared to relying on RA solely from gas-fired resources.

The CPUC's resource adequacy standards applicable to a CCE require several procurement targets. CCEs must secure the following three types of capacity and make it available to the CAISO:

- System capacity, which is capacity from a resource that is qualified for use in meeting system peak demand and planning reserve margin requirements;
- Local capacity, which is capacity from a resource that is located within a Local Capacity Area capable of contributing to the amount of capacity required in a particular Local Capacity Area; and

- Flexible capacity, which is capacity from a resource that is operationally able to respond to dispatch instructions to manage variations in load and variable energy resource output.

**Power Management/Schedule Coordinator**

Given the likely complexity of the CCE's resource portfolio, the CCE would want to engage an experienced scheduling coordinator to efficiently manage the CCE's power purchases and wholesale market transactions. The CCE's resource portfolio would ultimately include market purchases, shares of some relatively large power supply projects, as well as shares of smaller, most likely renewable resources with intermittent output. Managing a diverse resource portfolio with metered loads that will be heavily influenced by distributed generation may be one of the most important and complex functions of the CCE.

The CCE should initially contract with a third party with the necessary experience (proven track record, longevity and financial capacity) to perform most of the CCE's portfolio operation requirements. This would include the procurement of energy and ancillary services, scheduling coordinator services, and day-ahead and real-time trading.

Portfolio operations encompass the activities necessary for wholesale procurement of electricity to serve end use customers. These activities include the following:

- *Electricity Procurement* – assemble a portfolio of electricity resources to supply the electric needs of the CCE customers.

- *Risk Management* – standard industry risk management techniques would be employed to reduce exposure to the volatility of energy markets and insulate customer rates from sudden changes in wholesale market prices.

- *Load Forecasting* – develop accurate load forecasts, both long-term for resource planning, and short-term for the electricity purchases and sales needed to maintain a balance between hourly resources and loads.

- *Scheduling Coordination* – scheduling and settling electric supply transactions with the CAISO, with related back office functions to confirm SDG&E billing to customers.

The Partners' CCE should approve and adopt a set of protocols that would serve as the risk management tools for the CCE and any third-party involved in the CCE portfolio operations. Protocols would define risk management policies and procedures, and a process for ensuring compliance throughout the CCE. During the initial start-up period, the chosen electric suppliers would bear the majority of risk and be responsible for managing those risks. The protocols that cover electricity procurement activities should be developed before operations begin.

Based on conversations with scheduling coordinators currently working within the CAISO footprint, the estimated cost of scheduling services is in the $0.0001 to $0.00025/kWh range for large operating CCEs. This Study very conservatively assumes a cost of $0.0005/kWh, escalating at 2.5% annually, in all portfolios as a starting cost. Over time, as the CCE is operating, it is expected that the scheduling costs will decline to the $0.0002/kWh range.

## Resource Portfolios

Projected power supply costs were developed for three representative resource portfolios. Portfolios are defined by two variables:

(1) the share of renewable energy in the power mix (per the "Renewable Energy" discussion above), and
(2) the share of resources that are GHG-free in the power mix.

Renewable resources refer to resources that qualify under State and Federal RPS, such as solar and wind power. GHG-free power refers to energy sourced from any non-GHG emitting resource, including both the RPS-compliant sources mentioned above as well as nuclear power and large hydroelectric power. For this Study, no nuclear resources were included in the resource portfolio analysis.

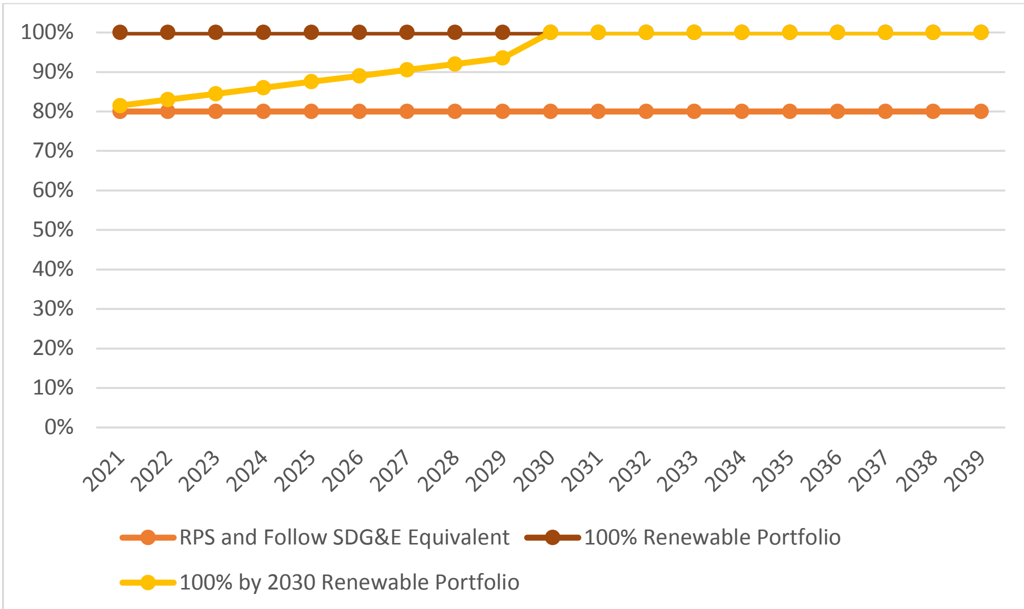
SDG&E's resource portfolio in 2016 included 43% renewable energy resources, 42% natural gas resources as well as 15% unspecified (market) purchases. In 2016, SDG&E's resource portfolio was 43% GHG-free. As the amount of load served by renewable resources increases each year, so too would the amount of load served by GHG-free resources. This is true of all three portfolios included in the Study.

In the "RPS Portfolio"[22] and "SDG&E-Renewable Equivalent" scenarios, it is assumed that the CCE resource portfolio is 80% GHG-free in all years. In the "100% Renewable by 2030 Portfolio" it is assumed that the CCE's resource portfolio is 80% GHG in 2021 and ramps up to 100% GHG-free in 2030. The "100% Renewable Portfolio" assumes 100% GHG free resources in all years. The GHG-free targets for each scenario are shown below in Exhibit 9. It is important to remember that Exhibit 8 above shows the percentage share of renewable energy in each portfolio, while Exhibit 9 below shows the GHG-free share of each portfolio.

It is assumed that the Partners' CCE would not modify its renewable energy or GHG-free achievements to match unexpected or abrupt changes in SDG&E's portfolio. Exhibit 9 below shows the GHG-free targets for the resource portfolios.

[22] The RPS Portfolio is included for comparison purposes but is not included as an alternative in the financial analysis.

**Exhibit 9**
**GHG-Free Targets assumed in Resources Portfolios**




In order to achieve the GHG-free targets shown above, it was assumed that a portion of the market power purchases used to serve load in each resource portfolio are sourced to GHG-free resources and that the CCE pays a premium for market Power Purchase Agreements (PPAs) sourced to GHG-free resources. A calendar year 2020[23] GHG-free premium of $0.004/kWh was assumed based on a survey of other CCEs. The GHG-premium is assumed to escalate annually by 5%. Given the assumed escalation rate, the premium paid for GHG-free power increases from $0.004/kWh in 2020 to $0.01/kWh in 2039. Including GHG-free premiums in the costs associated with a portion of market PPA purchases results in a $7/MWh increase in the 20-year levelized cost of each portfolio. Again, the portion of market PPAs that are sourced to GHG-free resources in each portfolio is based on the difference between the GHG targets (shown above in Exhibit 9) and the amount of renewable energy procured in each portfolio (shown above in Exhibit 8).

**Resource Options**

For each of the resource portfolios, a combination of resources has been assumed in order to meet the renewable energy and GHG-free targets, resource adequacy targets, and ancillary and balancing requirements. The mix of resources included in each portfolio are for analytical purposes only. The CCE should be flexible in its approach to obtaining the renewable and non-renewable resources necessary to meet these requirements.

Exhibit 10 shows the 20-year levelized resource costs used in this Study. It compares the costs of wholesale market power prices, a Power Purchase Agreement (PPA) tied to the wholesale

[23] Forecasts may have different base years, in the analysis all costs are escalated to begin in 2021.

market power prices, a local renewable energy resource, and the three portfolios evaluated in the Study.

**Exhibit 10**
**20-Year Base Case Levelized Resource Costs**
**(2018 $/kWh)**

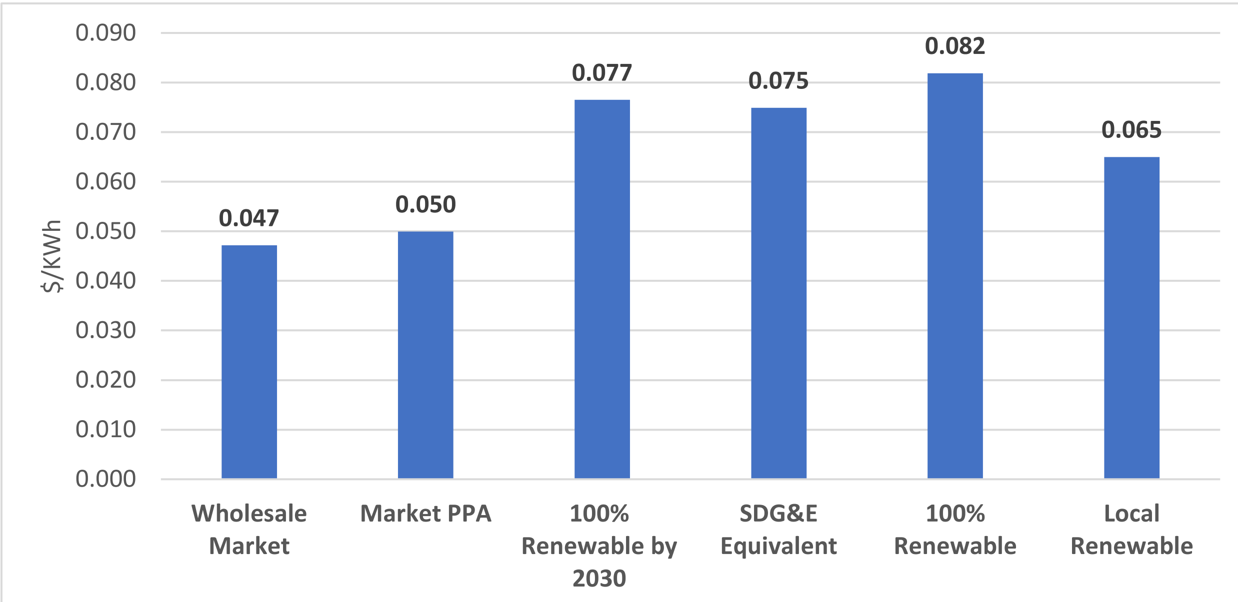



Exhibit 10 above shows a 20-year levelized PPA price of near $0.075/kWh under the SDG&E Equivalent Renewable, near $0.077/kWh for the 100% by 2030 Portfolio, and a price of near $0.082/kWh under the 100% Renewable Portfolio. The higher price in the 100% Renewable Portfolio is in recognition of the fact that the CCE may have to sign contracts for higher priced renewables in order to find a sufficient supply of renewables to meet the higher targets. The levelized resource costs shown above are for power only and do not include any ancillary services, scheduling or other costs.

Exhibit 10 also shows both spot wholesale market cost at $0.047 per kWh and market PPA cost at $0.05 per kWh. Market PPA costs are greater than spot wholesale market costs in recognition of the cost of the PPA supplier absorbing the market fuel price risk associated with providing a long-term PPA contract price.

The capacity factor for market PPA purchases is assumed to be 100% (flat monthly blocks of power). Capacity factor is equal to average monthly generation divided by maximum hourly generation in a given month. A 100% capacity factor implies that the same amount of power was purchased or generated each hour. The average monthly capacity factor for renewable resources and local renewables is assumed to be 33% based on the capacity factors of existing renewable resources operating in California.

On a $/watt basis, the cost of smaller scale solar projects is greater than the cost of large-scale solar projects. It is expected that the cost of smaller local renewable resources is $0.065/kWh based on information related to recent projects. The advantage of local renewable projects is lower transmission costs and less stress on the congested transmission grid.

The renewable energy requirements in the State's RPS are based on retail energy sales. Retail energy refers to the amount of energy sold to customers as opposed to the amount of energy purchased from generation sources (wholesale energy). Wholesale energy purchases must always exceed retail energy sales to account for transmission and distribution system losses. To be consistent, it was assumed that the renewable energy targets included in the portfolios apply to retail energy sales.

**Renewable PPA Pricing Alternative Scenario**

This section of the Study considers an alternative resource portfolio in which renewable PPA contract prices are lower than the base case prices described above. The base case renewable contract prices included in the Study are based on two conservative assumptions: 1) the majority of renewable energy purchases are made at short-term, rather than long-term, renewable contract prices and 2) the long-term renewable contract price is relatively high compared to the price at which existing CCEs are currently transacting. These conservative assumptions are described in greater detail below.

*Short-Term Renewable Energy Contract Price*

Short-term contracts have a term of one to three years. Short-term contract prices include two components: a price for energy that is based forward wholesale market prices and a price for Renewable Energy Credits (RECs). The Study's base case assumes that RECs are priced at $17/REC for bucket 1 RECs and $11/REC for bucket 2 RECs (1 REC = 1 MWh). Both bucket 1 and bucket 2 REC prices were assumed to escalate 1.5 percent annually. The base case also assumes that 75 percent of RECs acquired under short-term renewable contracts were bucket 1 RECs. Given these assumptions, the short-term renewable contract price escalated from $54/MWh in 2021 to $70/MWh by 2030. This pricing is used for short-term renewable energy contracts in all cases in this study.

*Long-Term Renewable Energy Contract Price*

The Study's base case includes a long-term renewable PPA fixed contract price of $42/MWh (all years). The $42/MWh assumption is conservative as other CCEs are currently signing PPAs for the output of solar projects with flat contract prices of near $30/MWh.

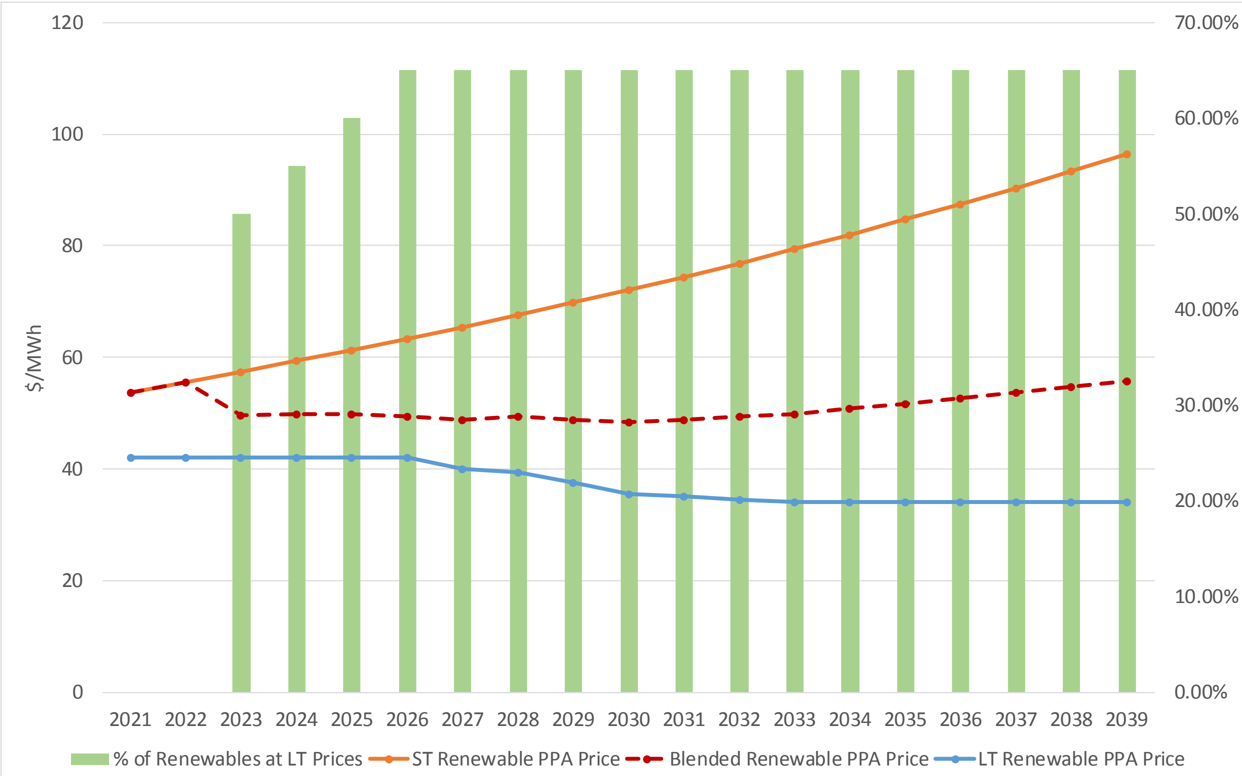
Consistent with the base case, the alternative scenario assumes a long-term renewable PPA price of $42/MWh in 2021 through 2026. However, the power cost model was updated to assume that lower priced long-term renewable PPA prices are slowly layered in beginning in 2027. In 2027 the average long-term renewable PPA price was reduced to $40/MWh. It is assumed that long-term renewable contracts with lower fixed prices continue to be layered in and decrease the average long-term renewable PPA price to $39.5/MWh in 2028, $37.5/MWh in 2029 and $35.5/MWh in 2030. While the $2/MWh decreases in 2028 and 2029 may seem relatively large, the $35.5/MWh price in 2030 is still $5 to $6/MWh greater than the prices at which existing CCEs are currently executing contracts. Therefore, the updated long-term renewable PPA prices are still fairly conservative.

The base case assumes that the majority of renewable energy purchases are made at short-term renewable contract prices. Specifically, during the first three years of operation all renewable energy is acquired through short-term renewable PPAs. The amount of renewable energy sourced to long-term renewable PPAs increased to 10 percent in year 4, 20 percent in year 5 and 25 percent in years 6 through 20.

In the alternative power supply scenario, the amount of renewable energy that is sourced to long-term renewable PPAs is increased. It is assumed that all renewable energy is acquired through short-term PPAs in the first two years of operation. The amount of renewable energy assumed to be acquired through long-term renewable PPAs was increased to 50 percent in year 3, 55 percent in year 4, 60 percent in year 5 and 65 percent in years 6 through 20.

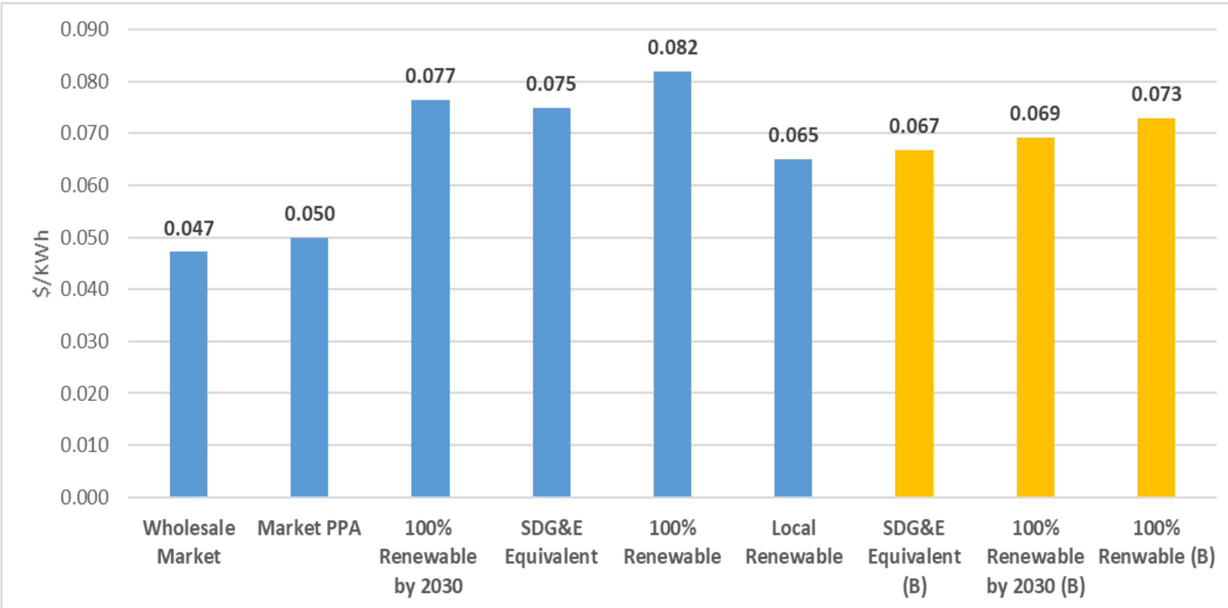
The revised assumptions regarding a) the amount of renewable energy purchased through long-term renewable energy PPAs and b) the prices at which renewable energy is purchased are illustrated below in Exhibit 11.

**Exhibit 11**
**Alternative Renewable Energy Prices and Composition**




The updated renewable energy PPA prices allow the CCE to reach its Renewable Portfolio Standard and rate savings targets. Exhibit 12 below compares the 20-year levelized costs of the portfolios with the lower renewable energy PPA pricing assumptions included in the alternative scenario to the portfolio costs included in the Study's base case. The portfolio costs in the alternative renewable PPA pricing scenario are shaded in orange and have a "B" notation. The levelized cost power in the "SDG&E Equivalent" portfolio decreased from $0.075 per kWh to $0.067 per kWh. As can be seen in Exhibit 12, the levelized costs for the "100% Renewable by 2030" and "100% Renewable" portfolios also decreased compared to the levelized costs included in the Study.

**Exhibit 12**
**Alternative Renewable Pricing Scenario**
**20-year Levelized Costs**

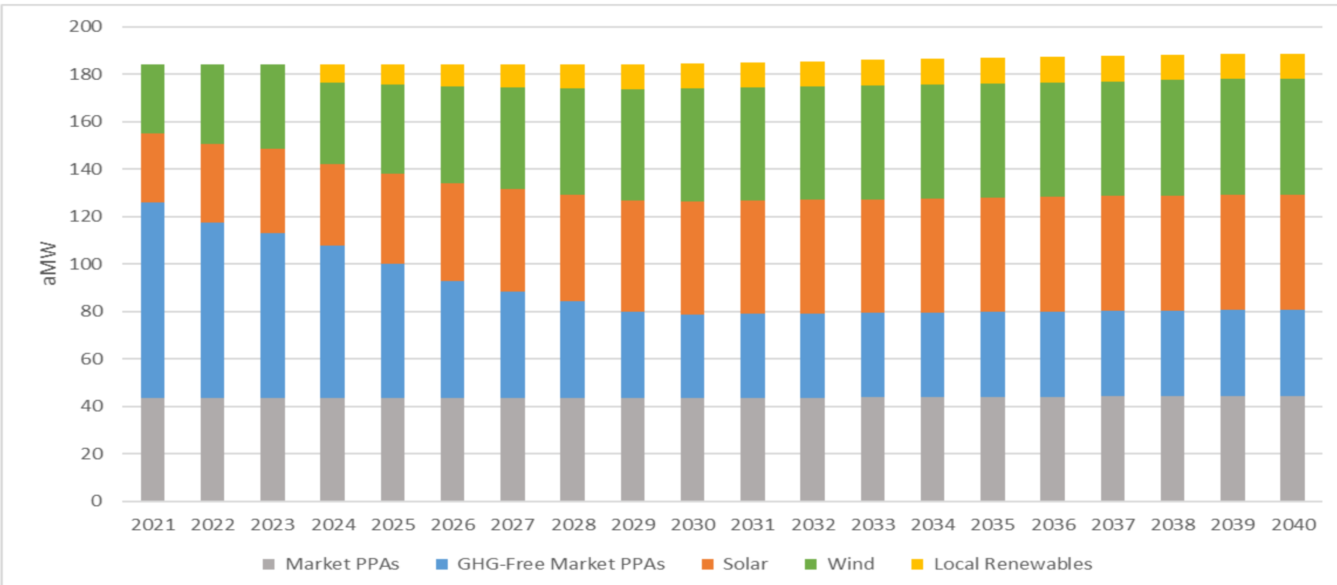



The reduced renewable energy PPA prices included in the alternative scenario more accurately reflect the resource portfolio of a functioning CCE. Reducing the assumed renewable energy contract prices, results in decreases in projected annual purchased power costs. The decreases in purchased power costs allow the CCE to "lock in" overall cost savings relative to SDG&E. Appendix C provides annual financial proforma results, including estimated rate savings for the CCE, for the alternative renewable PPA pricing scenario.

## RPS Portfolio

Exhibit 13 below shows the power supply portfolio that would be used to serve load in an RPS Portfolio.

**Exhibit 13**
**RPS Portfolio: Meet RPS Targets (aMW)**




*Average annual megawatt or aMW is equal to annual megawatt-hours divided by the number of hours in a year.

The share of renewable energy increases each year along with California's RPS requirements. In all three portfolios it is assumed that local renewables would begin serving load in year five of operation (2026). It is assumed that 10% of renewable energy is purchased via local renewables, as opposed to non-local large-scale renewables, in all four portfolios.

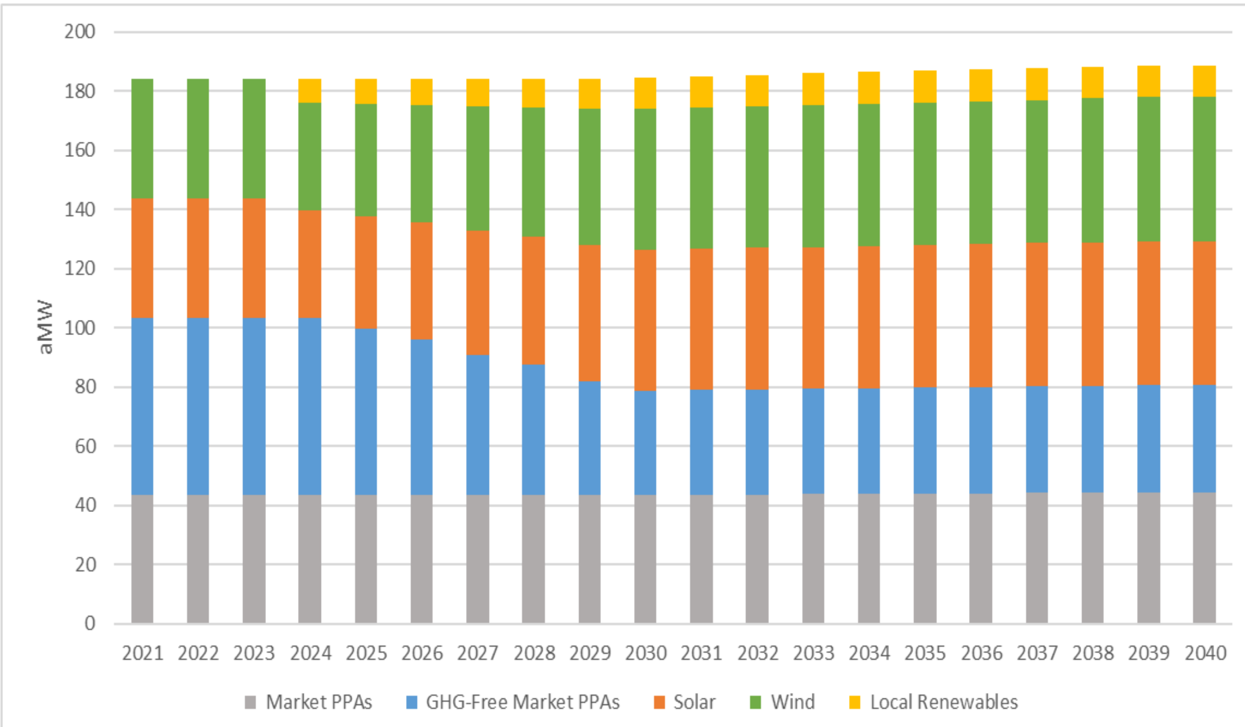
The source of the "market" purchases shown above in Exhibit 11 is unspecified. These market purchases could ultimately be sourced to a mix of renewable and non-renewable resources based on the availability of surplus resources in California and resources bid into CAISO for balancing energy purchases. For this Study's purposes, "market" purchases are assumed to be sourced to non-renewable generating facilities.

The "GHG-Free Market PPA" purchases shown above in Exhibit 11 are market purchases that are sourced to hydroelectric generating facilities. These market purchases would be procured through long-term PPAs. The cost of hydro power is assumed to be greater than the cost of unspecified market purchases. The premium of $0.0004/kWh applied to the cost of hydro power is discussed above in the "Resource Portfolios" section.

## SDG&E-Renewable Equivalent Renewables Portfolio

In this portfolio, the renewable energy purchases match the expected SDG&E renewable share based on recent information.[24] In Exhibit 14, the green and orange bars show renewable energy purchases (44%). Renewable energy purchases in 2021 through 2023 are greater than the RPS minimum requirement of 33%.

**Exhibit 14**
**SDG&E-Renewable Equivalent Renewables Portfolio (aMW)**



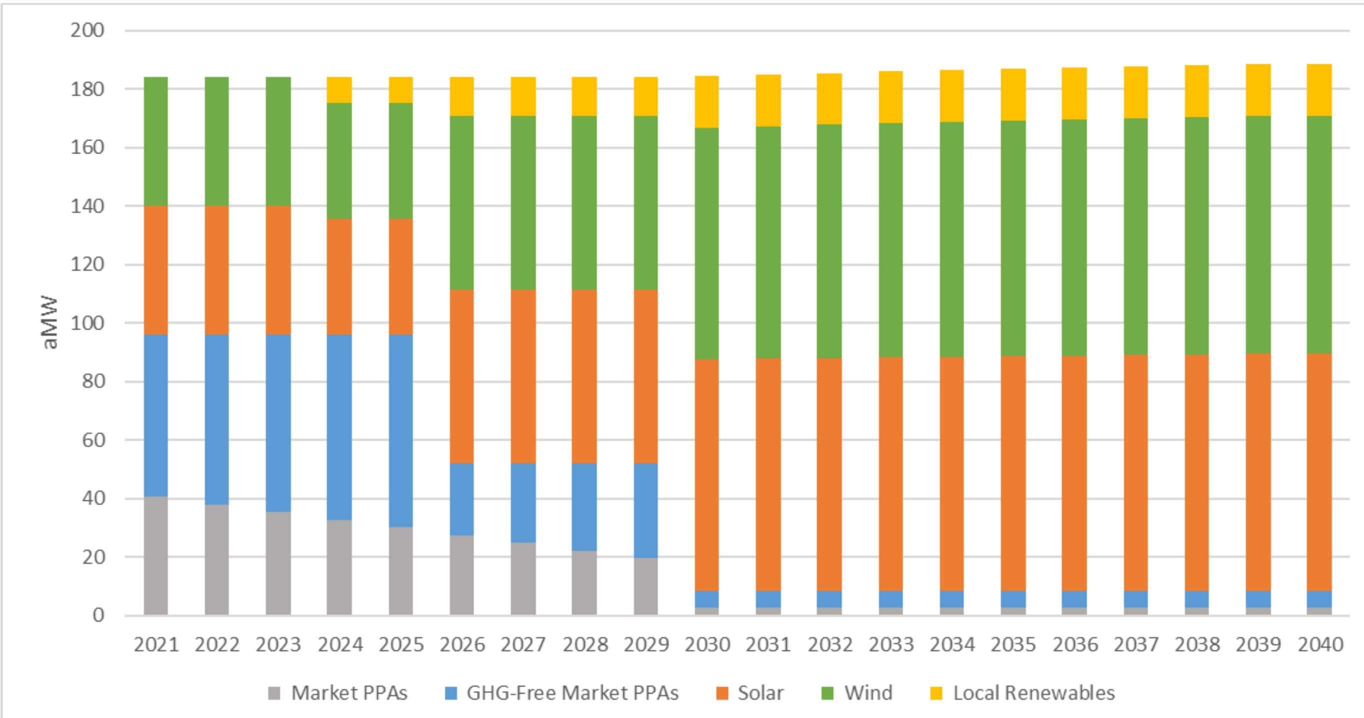

*Average annual megawatt or aMW is equal to annual megawatt-hours divided by the number of hours in a year.

[24] http://www.energy.ca.gov/pcl/labels/2016_index.html

**100% Renewable by 2030 Portfolio**

In this portfolio, a minimum of 50% of retail load is served by renewable resources through 2025, 75% through 2029 and 100% by 2030. Exhibit 15 illustrates this portfolio.

**Exhibit 15**
**100% Renewable by 2030 Portfolio (aMW)**

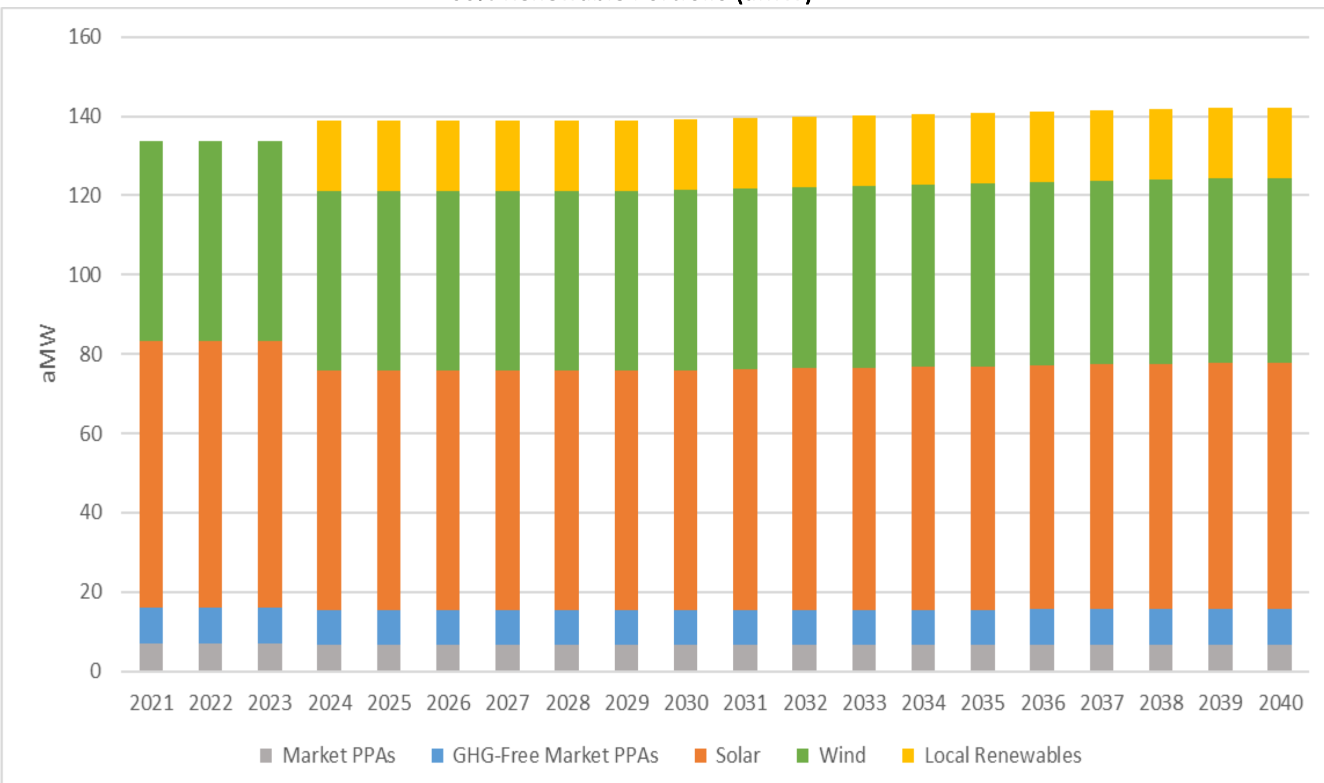



*Average annual megawatt or aMW is equal to annual megawatt-hours divided by the number of hours in a year.

**100% Renewable Portfolio**

In this portfolio, 100% of retail load is served by renewable resources in all years. As shown below in Exhibit 16 renewable energy purchases are the majority of the portfolio where market PPAs and GHG-Free Market PPAs are used only for load following.

**Exhibit 16**
**100% Renewable Portfolio (aMW)**

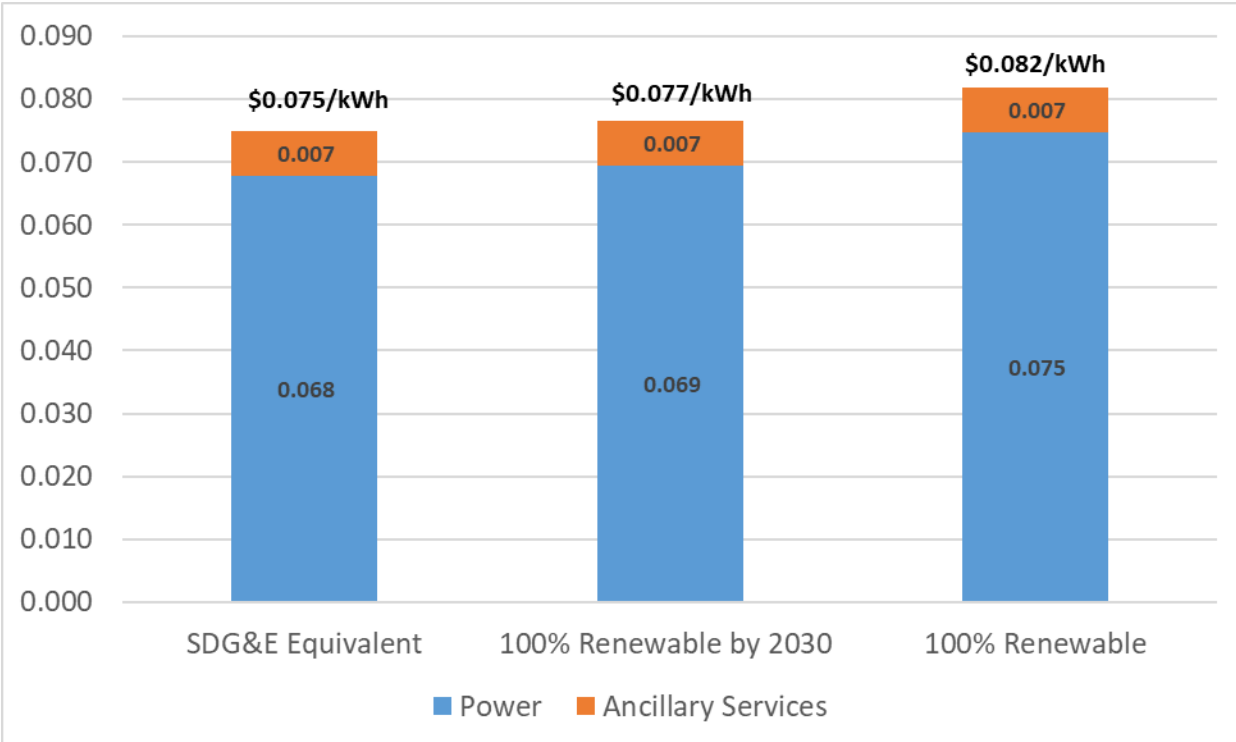



*Average annual megawatt or aMW is equal to annual megawatt-hours divided by the number of hours in a year.

### *20-Year Levelized Portfolio Costs*

The 20-year levelized costs have been calculated based on the base case assumptions detailed above regarding resource costs and resource compositions under the three portfolios. Exhibit 17 shows a breakdown of power, ancillary service and scheduling costs associated with each portfolio.

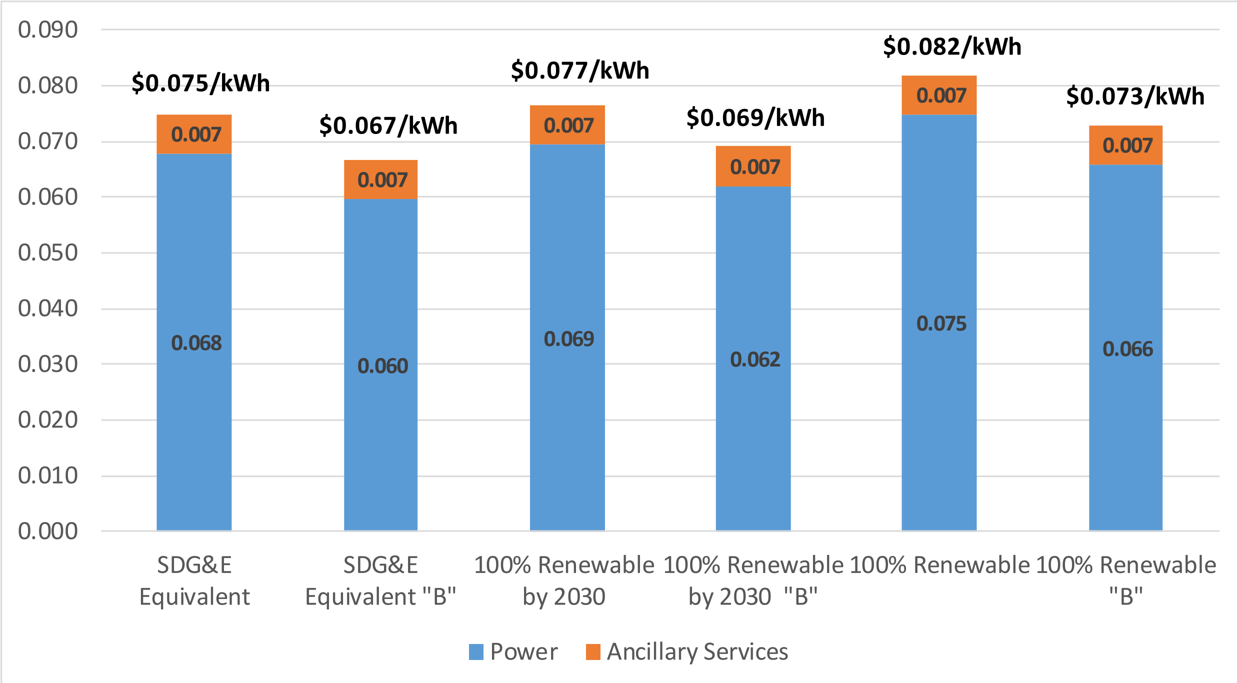
**Exhibit 17**
**20-year Levelized Base Case Portfolio Costs ($/kWh)**




As shown above, power costs under the three portfolios considered are fairly similar except for the 100% renewable portfolio. There is not a large variance in power costs between these portfolios because the majority of power is supplied by market PPAs and renewable energy purchases, which are very close in cost.

The 20-year levelized costs shown above in Exhibit 17 are based on the base case renewable PPA pricing assumptions. As discussed above, the base case renewable PPA prices are conservative because the majority of renewable energy purchases are made at short-term, rather than long-term, renewable contract prices and the base case long-term renewable contract price is relatively high compared to the price at which existing CCEs are currently transacting. The 20-year levelized portfolio costs were calculated using the alternative renewable PPA pricing scenario discussed above. A comparison of the 20-year levelized costs under the base case and the alternative scenario are shown below in Exhibit 18.

**Exhibit 18**
**20-year Levelized Portfolio Costs under the Base Case and Alternative Scenario ($/kWh)**




The portfolio costs in the alternative renewable PPA pricing scenario have a “B” notation in Exhibit 18. As shown above, the reduced renewable PPA prices result in a $0.008 to $0.009/kWh decrease in 20-year levelized costs.

## Resource Strategy

The Partners’ electric portfolio may be managed by a third-party vendor, at least during the initial implementation period. Through a power services agreement, the Partners can obtain full service requirements electricity for its customers, including providing for all electric, ancillary services and the scheduling arrangements necessary to provide delivered electricity.

After operations have begun, the Partners could decide to sign long-term PPAs, which could minimize the CCEs exposure to market prices and provide the CCE with the ability to increase the renewable percentage over time. Additionally, it is recommended that the Partners engage with a portfolio manager or schedule coordinator, who has expertise in risk management and would work with the CCE to design a comprehensive risk management strategy for long-term operations. A portfolio manager or schedule coordinator would actively track the CCE’s portfolio and implement energy source diversification, monitor trends and changes in economic factors that may impact load, and identify opportunities for dispatchable energy storage systems or automatic controls for managing energy needs in real-time with the CAISO.

Once operational, the CCE will be subject to energy storage targets under AB 2514. The California Energy Storage Bill, AB 2514, was signed into law in September 2010 and established energy storage targets for IOUs, CCEs, and other LSEs in September 2013. The applicable CPUC decision established an energy storage procurement target for CCEs and other LSEs equal to 1% of their forecasted 2020 peak load. The decision requires that contracts be in place by 2020 and projects be installed by 2024.

# Cost of Service

This section of the Study describes the financial pro forma analysis and cost of service for a CCE for the Partners. It includes estimates of staffing and administrative costs, consultant costs, power supply costs, uncollectable charges, and SDG&E charges. In addition, it provides an estimate of start-up working capital and longer-term financial needs.

## Cost of Service for CCE "Base Case" Operations

The first category of the pro forma analysis is the cost of service for a CCE for the Partners' operations. To estimate the overall costs associated with CCE operations, the following components have been included:

- Power Supply Costs
- Non-Power Supply Costs
  - Staffing
  - Administrative costs
  - Consulting support
  - SDG&E billing and metering charges
  - Uncollectible costs
  - Reserves
  - New programs funding
  - Financing costs
- Pass-Through Charges from SDG&E
  - Transmission and distribution charges
  - Power Charge Indifference Adjustment (PCIA)

Once the costs of CCE operations have been determined, the total costs can be compared to SDG&E's projected rates. A detail of the various non-power supply costs is included in Appendix D.

## Power Supply Costs

A key element of the cost of service analysis is the assumption that electricity would be procured under a power purchase agreement (PPA) for both renewable and non-renewable power for an initial period. Power supply would likely be obtained by the CCE's procurement consultant prior to commencing operations. The products and services required from the third-party procurement consultant are energy, capacity (System, Local and Flexible RA products), renewable energy, GHG-free energy, load forecasting, CAISO charges (grid management and congestion), and scheduling coordination.

The calculated 20 year levelized cost of electric power supply, including the cost of the scheduling coordinator and all regulatory power requirements, is estimated between $0.075 and $0.082 per kWh as discussed in the previous chapter. This price represents the price needed to meet the load requirements of the CCE customers while meeting required regulations (SB 350 and SB 100) and objectives of the CCE. The variation in price is a function of the desired level of renewable resources.

Three power supply scenarios are modeled for this Study have been discussed in previous sections. As a reminder the scenarios are:

(1) SDG&E Renewable Equivalent
(2) 100% Renewable by 2030
(3) 100% Renewable

## Non-Power Supply Costs

While power supply costs would make up the vast majority of costs associated with operating the Partners' CCE (roughly 80-90% depending on the portfolio scenario), there are additional cost components that must be considered in the pro forma financial analysis. These additional non-power supply costs are described below.

**Estimated Staffing Costs**

Staffing is a key component of operating a CCE. This Study assumes the Partners will proceed with the JPA operating model. All staffing costs are detailed in Exhibit 17.

The Partners' CCE would have discretion to distribute operational and administrative tasks between internal staff and external consultants in any combination. For this Study, two scenarios are explored that are considered to be at the maximum and minimum of this spectrum. The first option involves hiring internal staff incrementally to match workloads involved in forming the CCE, managing contracts, and initiating customer outreach/marketing during the pre-operations period (Full Staff Scenario). In the alternative approach, the CCE would hire just four staff internally and contract out the remaining work to consultants (Minimum Staff Scenario). Throughout the rest of this Study, it is assumed that the Partners' CCE will opt for the Full Staff Scenario to be conservative in the Study's economic analysis, but both options are discussed. The Full Staff Scenario is likely the most-costly option that the CCE could pursue and the details of the staffing plan would be part of the JPA between partners.

*Minimum Staff Scenario*

To build the minimum staff possible to run the Partners' CCE, all necessary tasks would be completed by consultants on a contract basis. It is assumed that these contracts would be managed by the Executive Director and two in-house staff, such as the Communication Outreach

Manager, a Director of Administration and Finance and a Director of Power Resources. In addition, consultants would have to be hired to manage the tasks not managed by full-time staff. This study focuses on the Full Staff Scenario described below, the Minimum staff scenario would be lower cost to implement and therefore the Full Staff Scenario is more conservative.

*Full Staff Scenario*

Exhibit 19 provides the estimated staffing budgets for a full staff CCE scenario for the start-up period (Pre-launch in 2020 through full operating in 2021). Staffing budgets include direct salaries and benefits. Prior to program launch, it is assumed that an operating team would be employed per the example of other CCEs in California thus far to implement the launch of a CCE program. This operating team typically includes an Executive Director, a Director of Administration and Finance, a Communication Outreach Manager and a Director of Power Resources. The remaining functions would be filled as quickly as possible.

**Exhibit 19**
**CCE Staffing Plan (Full Staff Scenario)**

| CCE Staff Positions | 2020* Pre-launch | 2021 Launch |
|---|---|---|
| Executive Director | 1 | 1 |
| Director of Marketing and Public Affairs | 0 | 1 |
| Account Service Manager | 0 | 1 |
| Account Representative | 0 | 1 |
| Communication Outreach Manager | 1 | 1 |
| Communication Specialist | 0 | 1 |
| Director of Power Resources | 1 | 1 |
| Director of Administration and Finance | 1 | 1 |
| Power Resource Analyst | 0 | 1 |
| Power Supply Compliance Specialist | 0 | 1 |
| Administrative Assistant | 0 | 1 |
| Total Number of Employees | **4** | **11** |
| Total Staffing Costs | $389,299 | $2,204,114 |

*Represents only partial year (6 months).

Based on this staffing plan, the Partners' CCE would initially employ 4 staff members. Once the CCE launches, it is anticipated that staffing would increase to approximately 11 employees within the first year of operation.

### Administrative Costs

Overhead needed to support the organization includes computers and other equipment, office furnishings, office space, utilities and miscellaneous expenses. These expenses are estimated at $28,000 during program pre-start-up. Office space and utilities are ongoing monthly expenses that would begin to accrue before revenues from program operations commence, and are; therefore, included in start-up costs that would be financed.

It is estimated that the per employee start-up cost is approximately $7,000. This expense covers computer and furniture needs. An additional annual expense of $15,000 for office space, and approximately $10,000 per year in office supplies and utilities costs is expected. Miscellaneous start-up costs of $102,000 are estimated for 2021 to address the general cost of mailing notifications, meetings, communication and other start-up activities. In addition, it is assumed that computers would need to be replaced every 5 years. Finally, additional miscellaneous expense budgets are estimated for general start-up costs in 2020. All administrative costs for start-up are shown in Exhibit 20. These costs are based on other start-up CCE operations. These costs are a very small portion of total operating costs that even a doubling of these costs from the below assumptions would not change the Study findings.

**Exhibit 20**
**Estimated Overhead Cost by Year (Full-Staff Scenario)**

| | 2020 | 2021 |
|---|---|---|
| **Infrastructure Costs** | | |
| Computers | $20,000 | $35,700 |
| Furnishings | $8,000 | $14,280 |
| Office Space | $0 | $15,300 |
| Utilities/Other Office Supplies | $0 | $10,200 |
| Miscellaneous Expenses | $0 | $102,000 |
| **Total Infrastructure Costs** | **$28,000** | **$177,480** |

The above costs are based on a full staff scenario. If the CCE determines in its business plan that hiring consultants rather than staff would be more cost-effective administrative costs would be reduced improving the feasibility of the CCE.

### Outside Consultant Costs

Consultant costs would include outside assistance for legal and regulatory work, communication and marketing, data management, financial consulting, technical consulting and implementation support.

CCE data management providers supply customer management system software, and oversee customer enrollment, customer service, as well as the payment processing, accounts receivable and verification services. The cost of data management is charged on a per customer basis and has been estimated based on existing contracts for similar sized CCEs. For this Study, the cost for data management is estimated at $1.25 per customer per month.

In addition, estimated funding for other consulting support (such as HR, legal, customer service, etc.) is provided. These costs have been estimated based on the experience of start-up consulting costs at other CCEs. Exhibit 21 shows the estimated consultant costs except for data management during the first three years. Consultant fees are provided on a monthly and annual basis in Appendix D.

**Exhibit 21**
**Estimated Consultant Costs by Year**

| | 2020 | 2021 | 2022 |
|---|---|---|---|
| Legal/Regulatory* | $0 | $374,500 | $382,000 |
| Communication | 34,000 | 208,000 | 106,100 |
| Financial Consulting** | 61,200 | 124,800 | 127,300 |
| Technical Consultant | 255,000 | 520,200 | 530,600 |
| Other Consulting/City Functions | 76,500 | 312,100 | 159,200 |
| **Total Consultant Costs** | **$426,700** | **$1,539,600** | **$1,305,200** |

*Legal/regulatory consulting refers only to legal counsel regarding CPUC compliance, filings, etc.

**Financial consulting includes legal fees for counsel on CCE financing.

The estimate for each of the services is based on costs experienced by other CCEs. Consultant costs are increased by inflation every year.

## SDG&E Billing & Metering Costs

SDG&E would provide billing and metering services to the CCE based on Schedule CCE: Transportation of Electric Power to CCE Customers. The estimated costs payable to SDG&E for services related to the Partners' CCE start-up include costs associated with initiating service with SDG&E, processing of customer opt-out notices, customer enrollment, post enrollment opt-out processing, and billing fees.

Customers who choose to receive service from the CCE would be automatically enrolled in the program and have 60 days from the date of enrollment to opt-out of the program. A total of four opt-out notices would be sent to each customer. The first notice would be mailed to customers approximately 60 days prior to the date of automatic enrollment. A second notice would be sent approximately 30 days later. Following automatic enrollment, two additional opt-out notices would be provided within the 60-day period following customer enrollment.

Based on SDG&E's current rate schedules, and CCE participation assumptions, SDG&E billing charges would be approximately $389,000 annually and initial setup costs and noticing would be on the order of $180,000 per year for 2020 and 2021, as shown in Exhibit 22.

| Exhibit 22<br>Utility Transaction Fees | | | |
|---|---|---|---|
| | 2020 | 2021 | 2022 |
| Total SDG&E Billing Fees | $0 | $389,000 | $390,000 |
| Notification and Setup costs | $180,000 | $184,000 | $0 |

## Uncollectible Costs

As part of its operating costs, the CCE must account for customers that do not pay their electric bill. While SDG&E would attempt to collect funds, approximately 0.2% of revenues are estimated as uncollectible.[25] This cost is therefore included in the CCE operating costs, or expense budget.

## Financial Reserves

The Partners' CCE is assumed to receive capital financing during its start-up through full operation. After a successful launch, the CCE must build up a reserve fund that is available to address contingencies, cost uncertainties, rate stabilization or other risk factors faced by the CCE. Therefore, this Study assumes that the CCE would begin building its reserve immediately upon launch. After three full operating years, it is estimated that the CCE will have accumulated enough reserves to cover three months of expenses. This level of reserves represents the *minimum* industry standard for electric utilities and would provide financial stability to assist the CCE in obtaining favorable interest rates if additional financing is needed. After that point, revenues that exceed costs could be used to finance a rate stabilization fund, new local renewable resources, economic development projects and/or lower rates. Exhibit 23 provides the estimate of the reserves available for local programs or rate stabilization.

[25] Based on SDG&E 2019 GRC uncollectible revenue as percent of total revenue.

| Exhibit 23<br>Estimated Reserves Under Base Scenario<br>Assuming 2% Rate Discount Off SDG&E Rates | | | |
|---|---|---|---|
| | **Cumulative Surplus*** | **Operating Reserves (4 months O&M)** | **Programs or Rate Reduction** |
| 2020 | $1,040,834 | $1,040,834 | $0 |
| 2021 | $36,426,945 | $36,426,945 | $0 |
| 2022 | $51,017,476 | $35,446,407 | $15,571,068 |
| 2023 | $66,821,209 | $35,527,660 | $6,589,109 |
| 2024 | $79,417,870 | $36,925,937 | $11,198,385 |
| 2025 | $92,520,717 | $38,577,598 | $11,451,185 |
| 2026 | $103,191,391 | $39,892,548 | $9,355,724 |
| 2027 | $111,642,089 | $41,286,828 | $7,056,418 |
| 2028 | $118,694,926 | $42,703,313 | $5,636,352 |
| 2029 | $123,331,689 | $44,179,264 | $3,160,811 |
| 2030 | $125,615,569 | $45,642,936 | $820,208 |

* Includes cash from financing

The new program funding amount decreases over time due to the conservative 1% growth in SDG&E generation rates and persistently high PCIA. After 2030, SDG&E stranded costs are expected to decrease significantly as contracts expire (resulting in lower PCIA rates). It is expected that programs and rate discounts could be provided well beyond the term of this Study. These financial reserves are documented in Appendix B.

## Financing Costs

In order to estimate financing costs, a detailed analysis of working capital needs, as well as start-up capital, is estimated. Each component is discussed below.

### Cash Flow Analysis and Working Capital

This cash flow analysis estimates the level of working capital that would be required until full operation of the CCE is achieved. For the purposes of this Study, it is assumed that the CCE pre-operations begin in July 2020. In general, the components of the cash flow analysis can be summarized into two distinct categories:

1. Cost of the CCE operations, and
2. Revenues from CCE operations.

The cash flow analysis identifies and provides monthly estimates for each of these two categories. A key aspect of the cash flow analysis is to focus primarily on the monthly costs and revenues associated with the CCE and specifically account for the transition or “phase-in” of the CCE customers.

The cash flow analysis also provides estimates for revenues generated from the CCE operations or from electricity sales to customers. In determining the level of revenues, the cash flow analysis assumes all customers are enrolled at the same time, based on the assumed participation rates, and assumes that the CCE offers rates that provide a discount compared to projected SDG&E rates corresponding to a total bill discount of 2% for each customer class.

The results of the cash flow analysis provide an estimate of the level of working capital required for the CCE to move through the pre-operations period. This estimated level of working capital is determined by examining the monthly cumulative net cash flows (revenues minus cost of operations) based on payment terms, along with the timing of customer payments.

The cash flow analysis assumes that customers will make payments within 60 days of the service month, and that the CCE would make payments to power suppliers within 30 days of the service month. It is assumed that payments for all non-power supply expenses would need to be paid in the month they occur. Customer payments typically begin to come in soon after the bill is issued, and most are received before the due date. Some customer payments are received well after the due date. Therefore, the 30-day net lag in payment is a conservative assumption for cash flow purposes.

For purposes of determining working capital requirements related to power purchases, the CCE would be responsible for providing the working capital needed to support electricity procurement unless the electricity provider can provide the working capital as part of the contract services. In addition, the CCE would be obligated to meet working capital requirements related to program management, the CPUC Bond of minimum $180,000[26] and a potential SDG&E program reserve. While the CCE may be able to utilize a line of credit, for this Study it is assumed that this working capital requirement is included in the financing associated with start-up funding.

A summary of working capital needs is presented below on Exhibit 24.

**Exhibit 24**
**Working Capital Needs**

| | **2020 Pre-Launch** | **2021 Launch** |
|---|---|---|
| Bonding & Security Requirement (CPUC) | $0.2 million | - |
| SDG&E Program Reserve | $0.6 million | - |
| Start-up Costs | $1.2 million | - |
| Working Capital (Cash Flow) | - | $14.0 million |
| **Total Capital Needed** | **$ 2.0 million** | **$14.0 million** |

[26] CPUC Decision 18-05-022

For comparison, Marin Clean Energy (MCE) started with $3.3 million in pre-launch funding[27] and is now operating with $21.7 million in working capital.[28] At initial launch MCE served electrical load roughly equivalent to 80-90% of the Partner CCE's estimated load.[29] Similarly, Sonoma Clean Power (SCP) acquired $6.2 million in pre-launch capital,[30] and now maintains working capital reserves of $25 million[31] while serving 25% more than the Partner CCE's estimated load.[32] The working capital needs after launch assumed in this Study are reflective of the experience of successfully operating CCEs on a $/GWh basis.

**Total Financing Requirements**

The start-up of the Partners' CCE would require a significant amount of start-up capital for three major functions: (1) staffing and consultant costs; (2) overhead costs (office space, computers, etc.) and (3) CPUC Bond and SDG&E security deposits.

Staffing, consultant and other program initiation costs have been discussed previously. In addition, the Public Utilities Code requires demonstration of insurance or posting of a bond sufficient to cover reentry fees imposed on customers that are involuntarily returned to SDG&E service under certain circumstances. SDG&E also requires a bond equivalent to the re-entry fee for voluntary returns to the IOU. This corresponds to the fees outlined in the CCE rate schedule from SDG&E, which are $1.12/customer for 2018. In addition, the bond must cover incremental procurement costs. Incremental procurement costs are power supply costs incurred by the IOU when a customer provides notice and returns to IOU bundled service.

For the Partners' CCE, the total financing requirement, including working capital, during the pre-launch to full operations, are estimated to be approximately $2 million, with approximately another $14 million following full enrollment. With more flexible power payment terms and/or customer payments of less than 60 days, capital requirements can be reduced by up to $7 million.

**Current CCE Funding Landscape**

The CCE market is rapidly expanding with increasingly proven success. To date, there are twenty operational CCEs in California and existing CCEs have demonstrated the ability to generate positive operating results. The early sources of that funded CCE start-up capital costs were community banks located in the CCE service territory, but now a mix of regional and large

[27]https://www.mcecleanenergy.org/wp-content/uploads/2016/01/MCE-Start-Up-Timeline-and-Initial-Funding-Sources-10-6-14-1.pdf
[28]https://www.mcecleanenergy.org/wp-content/uploads/2016/09/MCE-Audited-Financial-Statements-2015-2016.pdf
[29]https://www.mcecleanenergy.org/wp-content/uploads/2016/01/Marin-Clean-Energy-2015-Integrated-Resource-Plan_FINAL-BOARD-APPROVED.pdf
[30] https://sonomacleanpower.org/wp-content/uploads/2015/01/2014-SCPA-Audited-Financials.pdf
[31] https://sonomacleanpower.org/wp-content/uploads/2015/01/2016-05-SCP-Compiled-Financial-Statements.pdf
[32] https://sonomacleanpower.org/wp-content/uploads/2015/01/2015-SCP-Implementation-Plan.pdf

national banks have shown increased levels of interest evidenced by additional banks submitting proposals to CCEs looking for financing. As such, the Partners would likely have access to an adequate number of potential financial counterparties.

As CCEs have successfully launched across the State and a more robust data set of opt-out history becomes available, the financial community has demonstrated an increased level of comfort in providing credit support to CCEs. Most programs that have launched to date and those in development have relied on a sponsoring entity to provide support for obtaining needed funds. This support has come in varied forms, which are summarized in Exhibit 25.

**Exhibit 25**
**Forms of Support**

| CCE Name | Date | Pre-Launch Funding Requirement[1] | Funding Sources |
|---|---|---|---|
| Marin Clean Energy | 2010 | \$2- \$5 million | Start-up loan from the County of Marin, individual investors, and local community bank loan. |
| Sonoma Clean Power | 2014 | \$4 - \$6 million | Loan from Sonoma County Water Authority as well as loans from a local community bank secured by a Sonoma County General Fund guarantee. |
| CleanPowerSF | 2016 | ~\$5 million | Appropriations from the Hetch Hetchy reserve (SFPUC). |
| Lancaster Choice Energy | 2015 | ~\$2 million | Loan from the City of Lancaster General Fund. |
| Peninsula Clean Energy | 2016 | \$10 - \$12 million | PCE has also obtained a \$12 million loan with Barclays and almost \$9 million with the County of San Mateo for start-up costs and collateral. |
| Silicon Valley Clean Energy | 2017 | \$2.7 million | Loans from County of Santa Clara and City members \$21 million Line of Credit with \$2 million guarantee, otherwise no collateral. |
| Clean Power Alliance | 2018 | \$41 million | \$10 million loan from Los Angeles County and \$31 million Line of Credit from River City Bank. |
| Solana Clean Energy | 2018 | N/A | Vendor Funding |
| East Bay Clean Energy | 2018 | \$50 million | Revolving Line of Credit from Barclays. |

[1] Source: Respective entity websites and publicly available information. These funds are representative of CCE funding at different times of start-up.

A review of the current state of options for obtaining funds for these initial phases is detailed below:

<u>Direct Loan from Cities</u> – Any of the Partner cities could loan funds from its General Fund for all or a portion of the pre-launch through launch needs. Start-up funding provided by the cities would be secured by the CCE revenues once launched. The cities would likely assess a risk-appropriate rate for such a loan. This rate is estimated to be 4.0% to 6.0% per annum.

Collateral Arrangement from Cities – As an alternative to a direct loan from the cities, the cities could establish an escrow account to backstop a lender's exposure to the CCE. The cities would agree to deposit funds in an interest-bearing escrow account, which the lender could tap should the CCE revenues be insufficient to pay the lender directly. The cities obligations would be secured by CCE revenues collected once the CCE achieves viability.

Loan from a Financial Institution without Support – Silicon Valley Clean Energy Authority (SVCEA) was able to use this option to fund ongoing working capital. After member agencies funded a total of $2.7 million in start-up funds, SVCEA obtained a $20 million line of credit without collateral. This is the most common financing options used by emerging CCEs. This arrangement requires a "lockbox" approach with a power provider. A lockbox arrangement requires the CCE to post revenues into a "lockbox" which power suppliers can access in order to get paid first before the CCE. This arrangement reduces the required reserves and collateral held by the CCE.

Vendor Funding – The CCE could negotiate with its power suppliers to eliminate or reduce the need for supplemental start-up and operating capital. However, the vendor funding approach can be less transparent as the vendor controls expenses and activities, and the associated cost may outweigh the benefit of eliminating or reducing the need for bank financing. This method was used by Solana Energy Alliance.

Revenue Bond Financing – This financing option becomes feasible only after the CCE is fully operational and has an established credit rating.

**CCE Financing Plan**

While there are many options available to the CCE for financing, the initial start-up funding is expected to be provided via short-term financing via a loan from a financial institution. The CCE would recover the principal and interest costs associated with the start-up funding via subsequent retail rate collections. This Study demonstrates that the CCE start-up costs would be fully recovered within the first three years of CCE operations.

The anticipated start-up and working capital requirements for the Partners' CCE through launch are approximately $2.2 million. Once the CCE program is operational, these costs would be recovered through retail rate collections. Actual recovery of these costs would be dependent on third-party electricity purchase prices and the rates set by the CCE for customers.

Based on several recent examples of CCE's obtaining financing for start-up and operating costs, this financial analysis assumes that the CCE would be able to obtain a loan for all $16 million with a term of 5 years at a rate of 5.5%. While the term of the loan is assumed to be 5 years, the repayment period assumed is 3 years. This is very conservative as most CCEs will operate on a line of credit for the majority of working capital needs.

The detail of the base case cash flow analysis is provided in Appendix B.

# Rate Comparison

This section provides a comparison of rates between SDG&E and the Partners' CCE. Rates are evaluated based on the CCE's total electric bundled rates as compared to SDG&E's total bundled rates. Total bundled electric rates include the rates charged by the CCE, including non-bypassable charges, plus SDG&E's delivery charges.

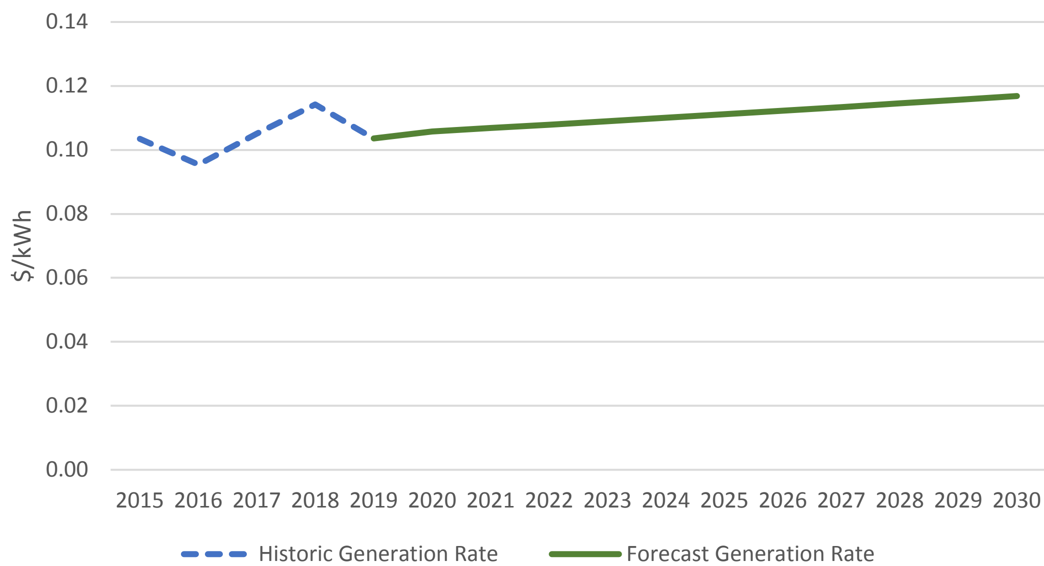
## Rates Paid by SDG&E Bundled Customers

Customers served by SDG&E will pay a bundled rate that includes SDG&E's generation and delivery charges. SDG&E's current rates and surcharges have been applied to customer load data aggregated by major rate schedules to form the basis for the SDG&E rate forecast.

The average SDG&E delivery rate, which is paid by both SDG&E bundled customers and CCE customers, has been calculated based on the forecasted customer mix for the Partners' CCE. The SDG&E rate forecast assumes that delivery costs will be based on SDG&E's recent General Rate Case (GRC) filing for 2019 to 2021. Thereafter, it is assumed that the delivery costs will increase by 2% per year based on inflation expectations.

Similarly, the average power supply rate component for SDG&E bundled customers has been calculated based on the projected CCE customer mix. Finally, the SDG&E generation rates have been projected to increase based on the renewable and non-renewable market price forecast, and the state's regulatory requirement for RPS, energy storage, and resource adequacy objectives. It is projected that SDG&E-owned resource and renewable cost escalation will be 1% over the 10-year analysis period. SDG&E does not provide detailed cost information or power supply price forecasts for the utility. Based on SDG&E's 2016 resource mix and RPS requirements, 50% to 60% of SDG&E's resources come from market purchases and natural gas resources for which costs grow based on market price changes. Market costs are expected to increase at a rate of 1% to 3% annually. The remainder of SDG&E's resources are from high priced long-term renewable contracts. While the cost of market purchases and natural gas are expected to increase, the cost of the renewable portfolio is expected to decrease over time as SDG&E's current contracts expire and new lower cost renewable contracts are obtained. The Study uses a conservative 1% growth rate for SDG&E generation costs beginning in 2020. This growth rate is conservative compared with the growth rate utilized in the San Diego Feasibility Study (roughly 2.5%). The SDG&E generation rate forecast can be seen in Exhibit 26.

**Exhibit 26**
**SDG&E Generation Rate**




## Rates Paid by CCE Customers

The Study assumes that the Partner CCE's rate designs would initially mirror the structure of SDG&E's rates so that similar rates can be provided to CCE's customers and bill comparisons can be made on an apples-to-apples basis. SDG&E is moving towards Time-of-Use (TOU) rates for all customers and it is assumed that the CCE would follow this transition initially. In determining the level of CCE rates, the financial analysis assumes all customers are enrolled at the same time and that the implementation phase costs are financed via start-up loans.

In addition to paying the CCE's power supply rate, CCE customers would pay the SDG&E delivery rate and non-bypassable charges also referred to as the Cost Responsibility Surcharge (CRS). The CRS is comprised of the following components: 1) Department of Water Resources Bond Charge (DWRBC), 2) Ongoing Competition Transition Charge (CTC) and 3) Power Charge Indifference Adjustment (PCIA). The DWRBC and CTC are charged to SDG&E's bundled customers in the SDG&E delivery charge. It is therefore assumed that the CCE customers would pay these charges as part of the delivery charges, as well. As such, the only additional non-bypassable charges that are payable to SDG&E by the Partners' CCE customers only is the PCIA.

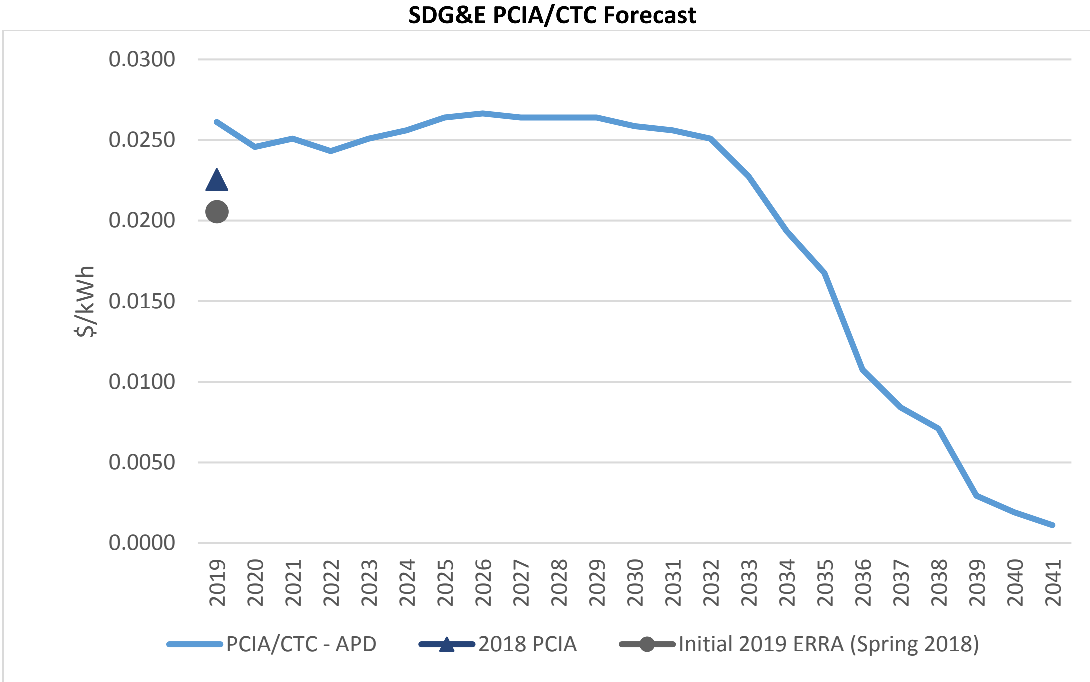
**Power Charge Indifference Adjustment**

The PCIA is an exit fee that is added to CCE rates to cover an IOU's stranded costs associated with energy purchases made to anticipated, but unrealized, demand because of customers leaving bundled service to receive service from a CCE.

On October 11, 2018 the CPUC voted unanimously to revise the PCIA methodology adopting the Alternative Proposed Decision (APD) methodology. This new methodology allows for more utility-owned resources to be included in the calculation and gets rid of the limits on cost recovery previously embedded in the old PCIA methodology. In addition, the new methodology allows for reductions in the stranded cost due to the value of renewable energy and resource adequacy provided by the resources. The APD methodology is not completely final as a Phase 2 study will commence in late 2018 to define some of the additional components of the methodology. However, the IOUs filed their 2019 PCIA calculations using the new methodology and current market conditions. The forecast below incorporates the latest decision, market conditions, and forecast stranded costs for departing SDG&E customers as seen in Exhibit 27.

As the chart shows, the PCIA drops significantly in the later years as SDG&E's existing power supply contracts and resources expire.

**Exhibit 27**
**SDG&E PCIA/CTC Forecast**

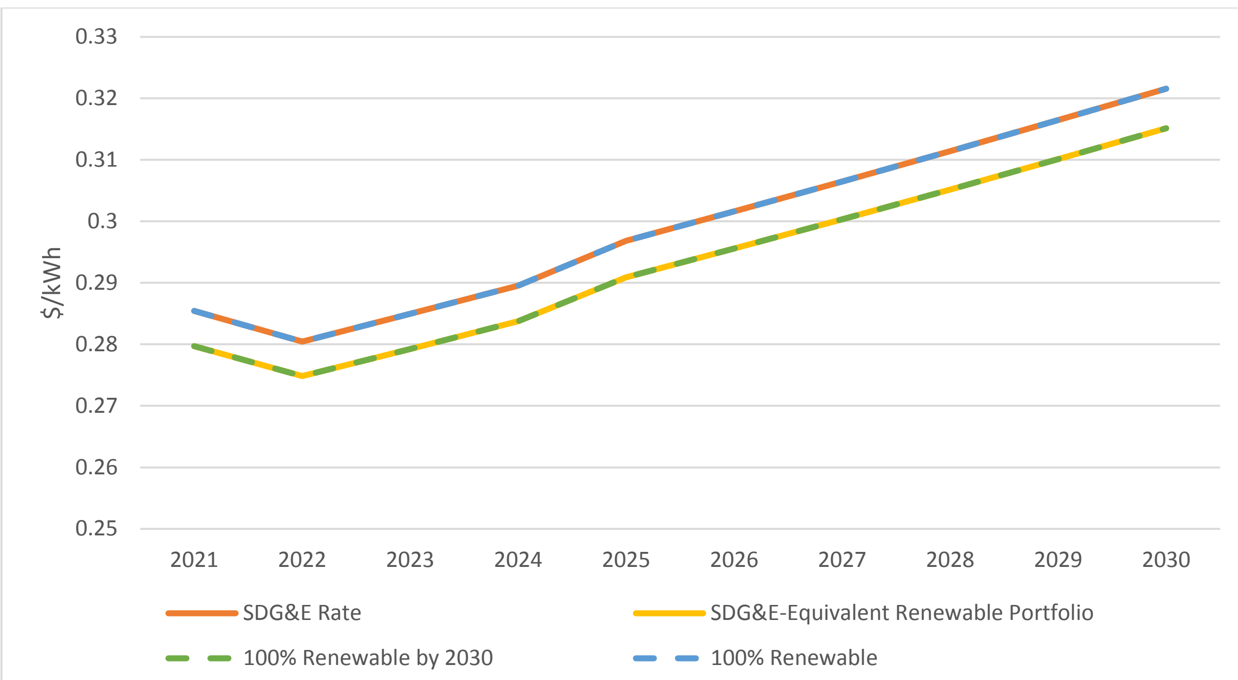


## Retail Rate Comparison

Based on the CCE's projected power supply costs, PCIA, operating costs, and SDG&E's power supply and delivery costs, forecasts of CCE and SDG&E total rates are developed. The analysis balances the rate discount, collection of reserves and the share of renewable and GHG-free resources purchased. If the discount is too high, the CCE will not be able to collect sufficient reserves to meet reserve targets within the first 3-4 years. If it is assumed that the CCE will purchase 100% renewable energy, then rates will have to be set close to SDG&E's rates in order for the CCE to collect sufficient revenues to meet costs and reserve requirements.

The rate forecasts are illustrated below in Exhibit 25. A rate discount of 2% is targeted for the SDG&E-Equivalent Renewable Portfolio and the 100% Renewable by 2030; therefore, those rates are equivalent in Exhibit 25. The 100% Renewable Portfolio rates are calibrated to closely match SDG&E rates while collecting the reserves needed for CCE operation. Exhibit 28 shows that the CCE could potentially offer 100% renewable energy at rates equal to SDG&E.

**Exhibit 28**
**Average Total Retail Rate Comparison – With Savings Targets**




Based on estimated CCE discounts, Exhibit 29 provides a comparison of the indicative bundled rates for CCE products based on the projected 2021 SDG&E rates. These indicative rates are calculated as a percentage off SDG&E's bundled rates. The CCE rates calculated in this Study are for comparison purposes only. Under formal operations, the CCE policymakers would determine the actual rates offered to its customers.

| Exhibit 29<br>Bundled Rate Comparisons<br>$/kWh | | | | |
|---|---|---|---|---|
| **Rate Class** | **2021 SDG&E *** | **SDG&E Equivalent Renewable** | **100% Renewable by 2030** | **100% Renewable** |
| Residential | 0.3494 | 0.3480 | 0.3480 | 0.3494 |
| Small Commercial | 0.2233 | 0.2317 | 0.2317 | 0.2233 |
| Medium Commercial | 0.2303 | 0.2203 | 0.2203 | 0.2303 |
| Street Lights | 0.2388 | 0.2390 | 0.2390 | 0.2388 |
| Agriculture | 0.1322 | 0.1325 | 0.1325 | 0.1322 |
| **Total** | 0.2854 | 0.2797 | 0.2797 | 0.2854 |
| **Initial Rate Savings in 2021 from SDG&E Bundled Rate** | | **2.00%** | **2.00%** | **0.00%** |

*SDG&E bundled average rate projections based on SDG&E's 2018 Rates.

A financial proforma in support of these rates can be found in Appendix B.

# Environmental and Economic Impacts

This section provides an overview of the potential environmental and indirect economic impacts to the San Diego area from the implementation of a CCE in the four Cities. In addition, potential future programs that could be offered by the CCE are outlined.

## Impact of Resource Plan on Greenhouse Gas (GHG) Emissions

At this time, SDG&E's resource mix is 43%[33] GHG-free due to power supply from renewable resources. The passing of SB100 accelerates the Renewable Portfolio Standard (RPS) obligations for retail sellers (investor-owned utilities (IOUs), CCEs, energy service providers (ESPs), and Public Owned Utilities (POUs)) as follows:

a) from 40% to 44% by 2024;

b) from 45%t to 52% by 2027; and

c) From 50% to 60% by 2030.

The bill also establishes state policy that RPS-eligible and zero-carbon (Clean Energy) resources supply 100% of all retail sales of electricity to California end-use customers no later than December 31, 2045. SDG&E is therefore expected to be 60% renewable and GHG free by 2030 and 100% GHG free by 2045.

As outlined in the Resource Portfolio section above, the CCE portfolio scenarios assumed that the CCE's resource portfolio is at least 80% GHG-free in all years. In the "SDG&E-Equivalent Portfolio" it is assumed that the Partners' CCE resource portfolio is 80% GHG-free in all years. In the "100% Renewable By 2030 Portfolio" it is assumed that the CCE's resource portfolio is 80% GHG-free in 2021 and that the GHG-free resources increase each year after 2021 until 2030 when GHG-free resources are 100%. In the "100% Renewable Portfolio" it is assumed that the CCE's resource portfolio is 100% GHG-free in 2021 and remains 100% GHG-free through 2030.

The remaining non-GHG-free energy would generate amounts of GHG emissions as outlined in Exhibit 30. The average portfolio GHG-free percentage over the ten-year study period (88%) was used for this calculation, to account for the higher GHG-free levels in later years. Average annual emissions from the three portfolios for 2021-2030 are presented below. In each case, it was assumed that the full CCE load (1,542 GWH) was in each portfolio. In other words, if, for example, the CCE decides to offer both 100% Renewable and 50% Renewables products and some proportion of customers fall into each product bucket, the emissions would fall somewhere between 222,000 and 272,000 metric tons of $CO_2e$/year.

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[33] http://www.energy.ca.gov/pcl/labels/2016_index.html

| Exhibit 30<br>Comparison of Average Annual GHG Emissions from Electricity, by Resource Portfolio (2021-2030) | | | | |
|---|---|---|---|---|
| | **SDG&E Equivalent Renewable Portfolio** | **100% Renewable by 2030** | **100% Renewable** | **SDG&E** |
| Avg./GHG Share | 80% | 89% | 100% | 60% |
| Avg. Emissions (Metric Tons CO2) | 109,000 | 61,000 | - | 218,000 |
| Difference SDG&E 60% Portfolio (Metric Tons CO2) | 109,000 | 157,000 | 218,000 | |
| Savings expressed as Number of Cars Off the Road[1] | 24,000 | 34,000 | 47,000 | 0 |

[1] Passenger cars, based on 4.6 metric tons of CO2 per year assuming 22 mpg and 11,500 miles per year.

## Local Resources/Behind the Meter CCE Programs

The CCE would have the option to invest in a range of programs to expand renewable energy use and enhance economic development in the Partner cities. Increased renewable energy use can be accomplished by supporting customers wishing to own small renewable generation (net energy metering), purchasing from small local for-profit renewable generators (feed-in tariffs), purchasing renewable resources directly, or supporting electric vehicle use. Each of these programs also yields economic development benefits by stimulating spending locally and saving local customers money. Economic development can also be accomplished by providing additional support for low-income customers or extra support for new or growing businesses. The following sections discuss these programs.

### Economic Development Rate Incentive

There are several programs that CCEs can offer to stimulate indirect local economic development in their service area. One is a special economic development rate to encourage job providers to locate within the CCE jurisdiction.

Another type of program that promotes economic development is to provide incentives for businesses to locate in the service area, remain there, or expand. For instance, the CCE could offer rebate programs or fund infrastructure costs for the business to target the business sectors of interest to their service area. If, for example, a large industrial customer would like to locate within the CCE service area, increased efficiency may result in decreased costs to all other customers due to overhead cost sharing, thus an incentive could be paid to the new industrial customer.

### Net Energy Metering (NEM) Program

The CCE could establish a Net Energy Metering (NEM) program for qualified customers in their service territory to encourage wider use of distributed energy resources (DER) such as rooftop solar. NEM programs allow energy customers who generate some or all of their own power to sell excess generation to the grid and benefit from a credit for those sales when they become a NEM consumer.

SDG&E currently offers a NEM program in which customers receive an annual “true-up” statement at the end of every 12-month billing cycle. This allows customers to balance credit earned in summer months (when solar energy generation is highest) with charges accrued in the winter (when solar generation is lower, and customers rely more on SDG&E’s bundled service). Customers earn power credits at the value of electricity and the value of renewable energy credits, though they are not paid for excess generation. Credits unused at the end of each year expire. This policy therefore incentivizes customers to limit the size of their generation system, as excess generation supplied to the grid will not provide a return.

All of the CCEs currently operating in California also offer NEM programs, and three of the most recently operational CCEs have offered them at the launch of service.[34] All of these CCE-managed NEM programs offer greater incentives for customers in their service area to invest in more and larger Distributed Energy Resources (DER). Higher incentives up to the full retail rate have been offered. This has the benefit of increasing the supply of renewable resources available to these CCEs as well as encouraging high participation rates among current and potential NEM customers. The Partner cities would have the option to implement a similar NEM program and the ability to stimulate local economic development in the form of new DER system investments and associated business activity.

**Feed-in Tariffs**

Feed-in tariffs (FIT) offer terms by which electric service providers such as IOUs and CCEs purchase power from small-scale renewable electricity projects within their service territory. In contrast with NEM programs, which typically target owners of homes and small businesses who wish to install a rooftop photovoltaic (PV) system, FIT programs target owners of larger generation projects, in the range of 0.5-3 MW. These could be larger rooftop photovoltaic (PV) systems located at industrial sites or ground-mounted solar shade structures in parking lots. In developing a FIT program of its own, the Partners’ CCE could incentivize customers in their service area to develop local renewable resources.

**Local Generation Resources Development**

A final option to drive investment in local renewable generation resources within the CCE service area is for the CCE itself to build or acquire generation resources. For example, Marin Clean Energy (MCE) currently has 10.5 MW of CCE-owned local solar PV projects under development

[34] https://pioneercommunityenergy.ca.gov/home/nem-solar/, https://www.poweredbyprime.org/faq, http://www.applevalley.org/home/showdocument?id=18607

and is planning to develop or purchase up to 25 MW of locally constructed, utility scale renewable generating capacity by 2021.[35] This model of CCE-owned resources provides CCEs with a guaranteed renewable power source as well as local economic stimulus.

**Electric Vehicle (EV) Programs and Charging Stations**

Encouraging electric vehicle use can both increase load serving entity ("LSE") total load and simultaneously reduce greenhouse gas emissions within its service area. Many LSEs offer special rates for electric vehicle charging. SDG&E offers two non-tiered, time-of-use (TOU) plans for electric vehicle charging: EV-TOU-2 and EV-TOU-5 which combines the loads of vehicle charging with the load of the residence. The two programs offer different TOU periods. EV-TOU customers install a separate meter explicitly for vehicle charging.[36] TOU rates encourage vehicle charging at times when energy is cheapest, or system load is lowest. MCE offers a similar program for their customers with lower rates than the IOU.[37]

In addition to targeted rate programs, CCEs can encourage electric vehicle use by investing in local electric vehicle charging stations. Silicon Valley Power (SVP) opened the largest public electric vehicle charging center in the State in April 2016. The facility features 48 Level 2 chargers and one DC Fast Charger.[38] Sonoma Clean Power (SCP) also provided qualified customers with incentives to purchase EVs in 2016 and continued the program in 2017.[39] The Partners' CCE could invest in similar projects to promote electric vehicle use within its service area.

**Low Income Programs**

SDG&E offers assistance to low-income customers on both one-time and long-term bases. For customers in need of sustained assistance, SDG&E offers rates that are up to 30% lower for qualifying households under the California Alternate Rate Energy (CARE)[40] program. The CARE program is mandatory for IOUs per California Public Utilities Code 739.1. The program is set up for electric corporations that have 100,000 or more customer accounts to provide 30-35% discount on electric utility bills on households that are at or below 200% of the federal poverty line. Funding for CARE is collected on an equal cents/kWh basis from all customer classes except street lighting. This program, like other SDG&E low income programs, would continue to be available to CCE customers through SDG&E.

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[35] https://www.mcecleanenergy.org/wp-content/uploads/2017/11/MCE-2018-Integrated-Resource-Plan-FINAL-2017.11.02.pdf

[36] https://www.sdge.com/residential/pricing-plans/about-our-pricing-plans/electric-vehicle-plans

[37] https://www.mcecleanenergy.org/electric-vehicles/

[38] http://www.siliconvalleypower.com/Home/Components/News/News/5036/2065

[39] https://sonomacleanpower.org/sonoma-clean-power-launches-ev-incentive-program/

[40] https://www.sdge.com/residential/pay-bill/get-payment-bill-assistance/assistance-programs

In addition, the Family Electric Rate Assistance (FERA) Program can provide a monthly discount on electric bills. This program is designed for income-qualified households of three or more persons. Finally, the California Department of Community Services and Development (CSD) oversees a federal program, Low-income Home Energy Assistance Program (LIHEAP), which offers help for heating or cooling homes and help for weatherproofing homes.

At present, most California CCEs simply match their incumbent IOU's low-income programs, as in the case of MCE and SCP. The Partners' CCE would provide the same support to low-income customers as does SDG&E.

## Economic Impacts in the Community

The analyses contained in this Study of forming a four-city CCE has focused only on the direct economic effects of this formation. However, in addition to direct effects, indirect microeconomic effects are also expected.

The indirect effects of creating a CCE include the effects of increased commerce and disposable income. Within this Study, an input-output (IO) analysis is undertaken to analyze these indirect effects. The IO model estimated the impact in the economy of forming a CCE that would lead to lower energy rates for the CCE customers. Three types of indirect impacts are analyzed in the IO model. These are described below.

**Local Investment** – The CCE may choose to implement programs to incentivize investments in local distributed energy resources (DER). Partners in the CCE may choose to invest in local DER generation projects. These resources can be behind the meter or community projects where several customers participate in a centrally located project (e.g. "community solar"). This demand for local renewable resources would lead to an increase in the manufacturing and installation of DER, and lead to an increase in employment in the related manufacturing and construction sectors.

**Increased Disposable Income** – Establishing a CCE would lead to reduced customer rates for energy, more disposable income for individuals, and greater revenues for businesses. These cost savings would then lead to more investment by individuals and businesses for personal or business purposes. This increase in spending would then lead to increased employment for multiple sectors such as retail, construction, and manufacturing.

**Environmental and Health Impacts** – With the creation of a CCE, other non-commerce indirect effects would occur. These may be environmental, such as improved air quality or improved human health due to the CCE utilizing more renewable energy sources, versus continuing use of traditional energy sources which may have a greater GHG footprint. While a change in GHG emissions is not modeled directly in economic development models used in this Study, the reduction of these GHG emissions are captured in indirect effects projected by the models to the extent that carbon prices are accounted for in the input-output matrix.[41]

**Input-Output Modeling (IO Modeling)** – County-wide electric rate savings and growth in manufacturing jobs and other energy intensive industries are expected to spur economic development impacts. Exhibit 30 shows the effect $9 million in rate savings could have on the County economy as estimated in the San Diego County IMPLAN model.[42] The $9 million rate savings represents the minimum annual bill savings projected to occur once the CCE has achieved full operation if all of the Partner cities are included (SDG&E-Equivalent Renewable portfolio). The IMPLAN model is an IO model that estimates impacts to an economy due to a change to various inputs such as industry income, supply costs, or changes to labor and household income. Both positive and negative impacts can be measured using IO modeling. IO modeling produces results broken down into several categories. Each of these is described below:

- Direct Effects – Increased purchases of inputs used to produce final goods and services purchased by residents. Direct effects are the input values in an IO model, or first round effects.
- Indirect Effects – Value of inputs used by firms affected by direct effects (inputs). Economic activity that supports direct effects.
- Induced Effects – Results of Direct and Indirect effects (calculated using multipliers). Represents economic activity from household spending.
- Total Effects – Sum of Direct, Indirect, and Induced effects.
- Total Output – Value of all goods and services produced by industries.
- Value Added – Total Output less value of inputs, or the Net Benefit/Impact to an economy.
- Employment – Number of additional/reduced full time employment resulting from direct effects.

This Study uses Value Added and Employment figures to represent the total additional economic impact of the rate savings associated with CCE formation.

The projected rate savings are modeled for residential, commercial, industrial, and agricultural sectors. For residential, the rate savings are modeled at different household income levels to estimate the impact on the economy from reduced bills. Estimated household income distribution is based on the income percentiles from the statistical atlas for San Diego County.[43]

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[41] Decreased health care costs have been modeled to make a major contribution to the local economy. e.g., DT Shindell, Y. Lee & G. Faluvegi, Climate and health impacts of US emissions reductions consistent with 2 °C; *Nature Climate Change* **volume 6**, pages 503–507 (2016)

[42] http://www.implan.com/

[43] Statistical Atlas. San Diego, California. Available online: https://statisticalatlas.com/county/California/San-Diego-County/Household-Income data from U.S. Census Bureau.

Exhibit 31 summarizes the high-level breakdown for income distribution within the county compared with the rest of the State.

**Exhibit 31**
**Household Income Distribution, San Diego County and California**[44]

The change in household income assumes that all households are impacted proportionately; however, in practice lower income households typically see the most significant benefit due to the disproportionate amount of total household income that goes to costs associated with household electricity use. Generally, lower income families are not able to reduce their utility bills as easily through efficiency upgrades or modified behavior due to lack of disposable income. Therefore, the overall impacts are likely underestimated.

Non-residential impacts are estimated using top 16 industries in Encinitas, Oceanside, Carlsbad, and Del Mar. Rate savings are allocated to each industry based on the share of revenue. This method assumes that energy use is positively correlated with industry revenue. Major agricultural activities in the County include nursery products, avocados, lemons, limes, tomatoes,

[44] Normalized with respect to standard interval of $5k. Gray areas represent percentile bands from the counties in California. © OpenStreetMap contributors Available online: https://statisticalatlas.com/county/California/San-Diego-County/Household-Income

and herbs. Major commercial and industrial industries include government, healthcare, retail, manufacturing, construction, professional and scientific services, finance, accommodation and food services, and wholesale trade.

Exhibit 32 details the macroeconomic impacts anticipated from the 2% savings in the generation rate after forming the CCE. The total Value Added for one year of rate savings is estimated at $7.7 million. Finally, the rate savings are estimated to produce an additional 109 full time jobs.

**Exhibit 32**
**$9 Million Rate Savings Effects on the San Diego County Economy[1]**

| Impact Type | Employment | Labor Income | Total Value Added | Output |
|---|---|---|---|---|
| Direct Effect | 50.7 | $2,473,000 | $2,508,000 | $4,613,000 |
| Indirect Effect | 10.7 | $641,000 | $1,039,000 | $1,740,000 |
| Induced Effect | 47.4 | $2,273,000 | $4,146,000 | $6,712,000 |
| **Total Effect** | 108.8 | $5,387,000 | $7,694,000 | $13,065,000 |

1. Full impacts to San Diego county are estimated, it can be expected that a large share of these impacts would be realized within the 4 jurisdictions.

These savings are based on the economic construct that households would spend some share of the increased disposable income on more goods and services. This increased spending on goods and services would then lead to producers either increasing the wages of their current employees or hiring additional employees to handle the increased demand. This in turn would give the employees a larger disposable income which they spend on goods and services and thus repeating the cycle of increased demand. In addition, reduced inputs to production for non-residential electric customers would allow companies to invest in other areas to promote growth such as hiring new employees, offering additional training, and purchasing upgraded equipment.

# Sensitivity and Risk Analysis

The economic analysis provides a Base Case scenario for forming a CCE. This Base Case is predicated on numerous assumptions and estimates that influence the overall results. This section of the Study will provide the range of impacts that could result from changes in the most significant variables for the portfolios described in the Power Supply Strategy and Cost of Service sections of this Study. In addition, this section will address uncertainties that should be addressed and mitigated to the maximum extent possible.

The following analysis is an overview of risks and their relative severity, followed by discussion of each factor. For variables where uncertainty is quantified, key assumptions are discussed, and a reasonable range of outcomes is established. The range in variable assumptions is meant to reflect probable futures, but do not demonstrate the full scope of possible outcomes. The CCE's rate impacts are estimated using a range of likely outcomes and presented in a scenario analysis.

When evaluating risks, it is important to note that power supply costs are approximately 56 percent of the total costs, SDG&E non-by-passable (PCIA/CTC) charges account for 35 percent, and operating costs account for 9% of total CCE revenue requirement. The figure below (Exhibit 33) illustrates this breakdown of CCE costs. Exhibit 34 provide discussion of each risk factor.

**Exhibit 33**
**Rate Comparison SDG&E Renewable-Equivalent Portfolio**

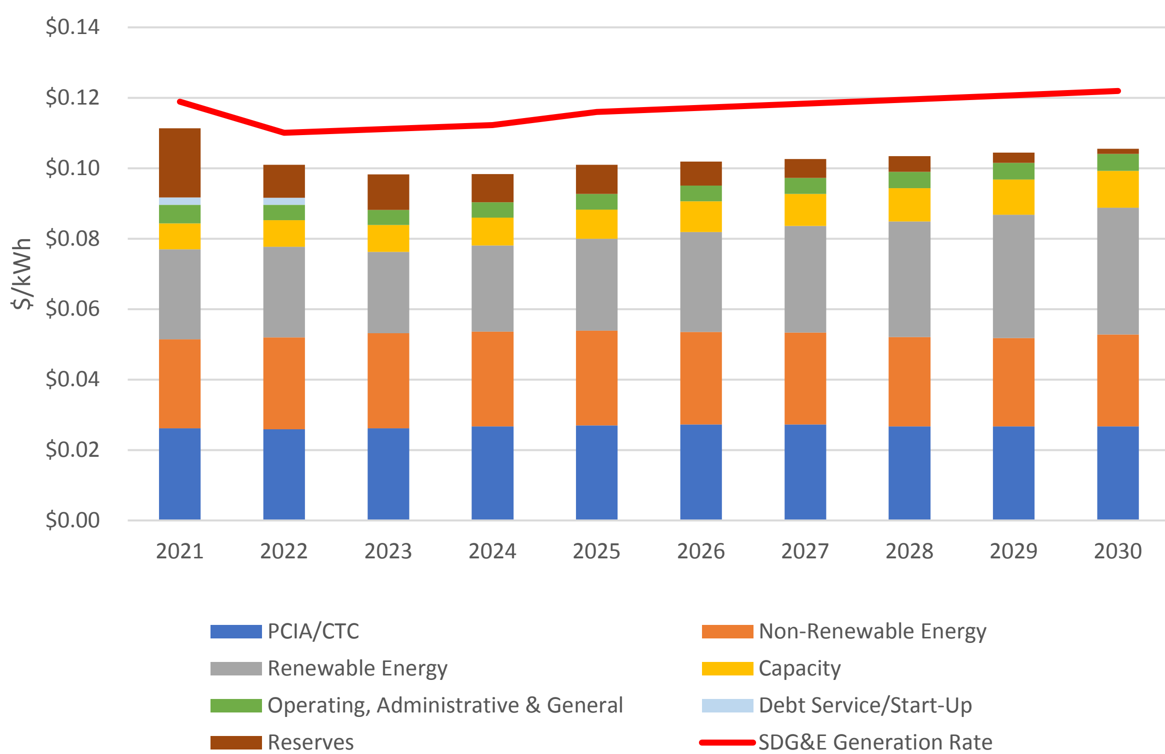


**Exhibit 34**
**Comparison of Risks, Mitigation Strategies, and Risk Severity**

| | Risk | Description | Problem | Mitigation Strategy | Likelihood of Problem | Severity of Problem | Potential to "Suspend" CCE |
|---|---|---|---|---|---|---|---|
| 1 | SDG&E Rates and Surcharges | SDG&E's generation rates decrease or its non-bypassable charges (PCIA/CTC) increase | • CCE rates exceed SDG&E<br>• Increased customer opt-out rate | • Establish Rate Stabilization Fund<br>• Invest in a balanced energy supply portfolio to remain agile in power market<br>• Emphasize the value of programs, local control, and environmental impact in marketing | High – most operating CCEs in California have undergone short periods of rate competition from the incumbent IOU. | Medium - CCEs have been able to buffer rate impacts using financial reserves, then adjust power supply to regain rate advantage. | Medium – depending on the outcome of the PCIA proceeding, CCEs may become infeasible |
| 2 | Regulatory Risks | Energy policy is enacted that compromises CCE competitiveness or independence | • New costs incurred<br>• Reduced authority | • Coordination with CCE community on regulatory involvement<br>• Hire lobbyists and regulatory representatives to advocate for CCE | Low – existing regulatory precedent and a growing market share makes the likelihood of state policies that severely disadvantage CCEs low. | High – a worst-case scenario regulatory legislative decision limiting CCE autonomy or enforcing additional costs could hinder CCE viability. | Medium – energy policy severe enough to make CCE infeasible is not likely. |
| 3 | Power Supply Costs | Power prices increase at crucial time for CCE | • CCE rates exceed SDG&E<br>• Increased customer opt-out rate | • Long-term contracts<br>• Draw on CCE reserves to stabilize rates through price spike | Low – market prices are unlikely to spike enough to make CCE financially infeasible prior to CCE launch. From that point on, the CCE can limit its exposure through contract selection. | Medium – a poorly timed price spike combined with poor power supply contract management could require CCE to dig into reserves or delay launch. | Low |
| 4 | SDG&E RPS Share | SDG&E's RPS or GHG-free power portfolio grows to match or exceed CCE 's | Increased customer opt-out rate | • Increase renewable power portfolio<br>• Emphasize rates and local programs in marketing | Medium – SDG&E's power portfolio is dynamic and could change rapidly as a result of other CCE departures. | Low – CCE would have capability to increase renewable energy purchases to match or exceed SDG&E if the event occurs. In | Very Low – CCE is likely to respond effectively if this occurs. |

| | Risk | Description | Problem | Mitigation Strategy | Likelihood of Problem | Severity of Problem | Potential to "Suspend" CCE |
|---|---|---|---|---|---|---|---|
| | | | | | | addition, CCE would promote other benefits of its service to customers. | |
| 5 | Availability of RPS/GHG-free power | Unexpectedly high market demand or loss of supply of renewable resources | • CCE unable to provide target power products | • Shift emphasis to GHG-free or RPS resources depending on availability<br>• Secure long-term contracts<br>• Invest in local renewable resources | Low – power procurement providers are projecting a plethora of RPS and GHG-free bids available on the market. | Medium – if CCE were unexpectedly unable to procure enough RPS or GHG-free power, it could emphasize other program strengths to retain customers until new resources came online. | Low – negligible chance of occurring. |
| 6 | Financial Risks | CCE is unable to acquire desired financing or credit | • Slower or delayed program launch<br>• Unable to build generation projects | • Adopt gradual program roll-out<br>• Establish Rate Stabilization Fund<br>• Minimize overhead costs | Low – CCEs have become sufficiently established in California, such that financing is almost certainly available. | Medium – in the event CCE is limited in financing options, it can adopt a more conservative program design and gradual roll-out. | Low |
| 7 | Loads and customer participation | Unprecedented opt-out rate reduces competitiveness | • Excess power contracts<br>• Poor margins | • Increase marketing<br>• Reduce overhead<br>• Expand to new customer markets<br>• Consider merging with existing CCE | Low – as CCEs have become more common in California, and CCE marketing firms more experienced, opt-out rates have gone lower. | Low –CCE would have numerous viable options in the event they suffer unexpectedly low participation. | Low |

## SDG&E Rates and Surcharges

Sensitivity analyses were conducted for two components of SDG&E rates. The delivery rates are paid by both CCE and SDG&E bundled customers. As such, changes in delivery rates impact all customers equally.

### Generation Rate

SDG&E generation rates are projected to increase on average by 1% per year over the next 10 years based on the projected market prices, SDG&E's resource mix and renewable resource growth rates. To explore the impact in the case that SDG&E's generation rate changes significantly relative to the CCE's generation cost, SDG&E's generation rates was modeled in the high and low case by incorporating higher and lower generation growth rates. This results in SDG&E's power supply average annual growth rate in the high case of +2% and in the low case of -2%.

### PCIA

When legislation was introduced to allow the formation of CCEs, it was recognized that the IOUs currently serving the potential CCE customers may face stranded generation costs. The PCIA methodology was established by the CPUC as a means for IOUs to recover those stranded costs. The PCIA faces several issues, however, including the source and transparency of data used for the calculation and the fact that the PCIA level is variable and contains a great amount of uncertainty.

The level of the PCIA, or other non-bypassable charge that will potentially replace the PCIA, would impact the cost competitiveness of the Partners' CCE. In order to be competitive, the CCE's power supply costs plus PCIA and other surcharges must be at or lower than SDG&E's generation rates. Many factors influence the PCIA, but primarily the PCIA is determined by the cost of power contracts and the cost to SDG&E of the departing load. Uncertainties surrounding the PCIA include methodology assumptions unique to SDG&E, as well as to what degree previously acquired power contracts can be retired. The potential for the PCIA to increase sharply occurs when SDG&E must sell previously contracted power at times when wholesale power prices are much lower. The PCIA also has potential to decrease since it reflects SDG&E's own resources and signed contracts obtained prior to load departure; once those contracts expire, the related PCIA would disappear. Therefore, over time the PCIA would vary, but it is expected that it would decline as market prices increase and grandfathered contracts expire.

Forecasting the PCIA is difficult since key inputs are heavily redacted from the rate filings and regulatory changes can significantly impact the PCIA. The uncertainty associated with forecast PCIA rates is modeled considering historic PCIA increases as well as the adopted methodology used for the PCIA calculation (October 11, 2018). In addition to the base case, a low and high PCIA forecast are modeled. The low scenario is 10% lower than the forecasted assumption. In the high scenario, the PCIA increases by the full cap of $0.005/kWh in the first 2 years then de-escalates at an average of 5% per year.

## Regulatory Risks

There are numerous factors that could impact SDG&E's rates in addition to the market price impacts described above. Regulatory changes, plant or technology retirements or additions, and gas prices all can impact SDG&E's rates in the future. Regulatory issues continue to arise that may impact the competitiveness of the Partners' CCE. The impact of these factors is difficult to assess and model quantitatively. However, California's operating CCEs have worked aggressively to address any potentially detrimental changes through effective lobbying at the California state legislature and at the California Public Utilities Commission.

New legislation can also impact the Partners' CCE. For example, new legislation that recently affected CCEs is SB 350. The CCE-specific changes reflected in SB 350 are generally positive, providing for ongoing autonomy with regard to resource planning and procurement. CCEs must be aware, however, of this legislation's long-term contracting requirement associated with renewable energy procurement. Specifically, CCEs are required to contract 65% of renewable resources for 10 years or more by 2020.

In addition, there is a risk that additional capacity resource costs are pushed onto CCEs via the Cost Allocation Mechanism (CAM). The CCE would need to continually monitor and lobby at the Federal, State and local levels to ensure fair and equitable treatment related to CCE charges.

Finally, SDG&E has asked lawmakers to introduce legislation (AB56) that would eventually result in the IOU leaving the power supply business. SDG&E is faced with losing half of its customers as the City of San Diego is poised to launch its CCE program. SDG&E is asking that the legislature pass a bill that would create a way for the utility to sell long-term power contracts to a "state-level electrical procurement entity." This entity could then re-sell the contracts to other buyers. Any difference in price would then become a non-bypassable charge to former SDG&E bundled customers. The non-bypassable charge would likely be similar to the PCIA/CTC and the PCIA/CTC would no longer be in effect. Because the state-level procurement entity would be a public agency, and be subject to a lower cost of capital, the new exit fee mechanism could result in lower charges to electric customers. These lower charges would benefit CCE customers.

## Power Supply Costs

Ramping services are predominantly provided by natural gas-fired generating resources. These resources are capable of ramping generation levels up and down quickly to assure that resources are equal to load requirements. Therefore, wholesale market prices are driven largely by natural gas prices. In addition, the CCE's power supply mix has been modeled according to different levels of renewable energy. Renewable energy costs are forecast for the base case; however, several factors could influence future renewable energy costs including locational factors for new facilities, transmission costs, technology advancements, changes in state and federal renewable energy incentives, or changes in California or neighboring state RPS.

Since resource costs are based on forecast wholesale market and renewable market prices, it is prudent to look at the sensitivity of the 20-year levelized cost calculations to fluctuations in projected prices. Exhibit 35 below shows a summary of low, mid-range, and high resource costs.

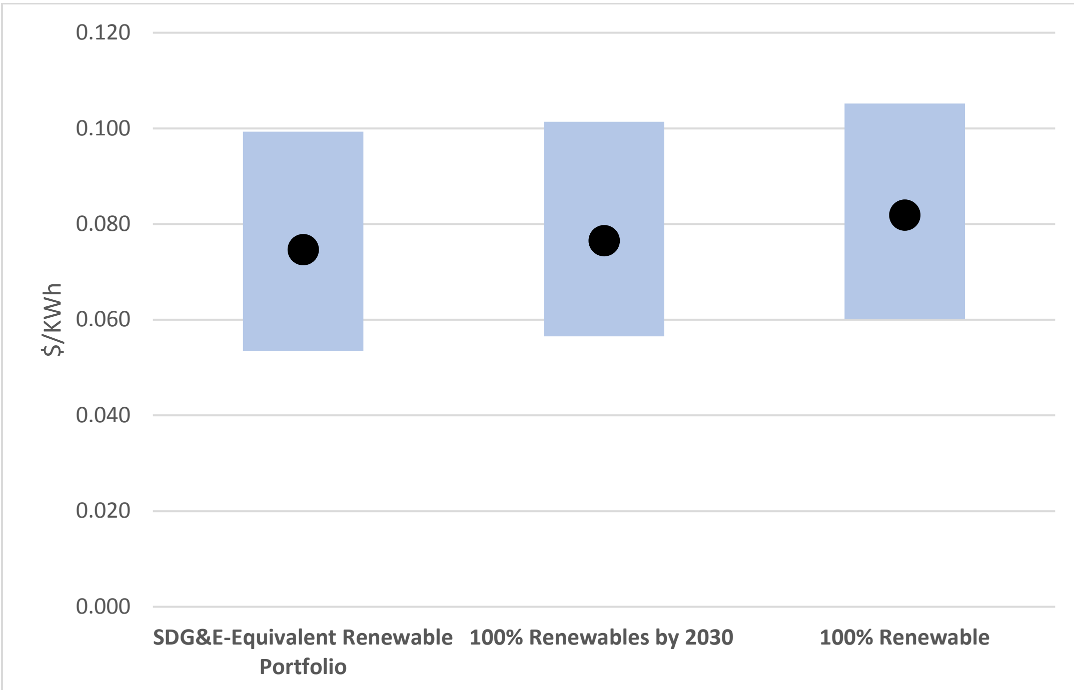
**Exhibit 35**
**Power Supply Cost Sensitivity**

| Case | RPS | SDG&E-Equivalent Renewable Portfolio | 100% Renewable by 2030 | 100% Renewable |
|---|---|---|---|---|
| Low Case | 0.0535 | 0.0537 | 0.0566 | 0.0602 |
| Mid-range | 0.0746 | 0.0749 | 0.0765 | 0.0819 |
| High Case | 0.0993 | 0.0996 | 0.1014 | 0.1052 |

As discussed in the "Power Supply Strategy and Costs" section of this Study, the Mid-range renewable energy costs are conservative in that they are greater than the cost of long-term renewable PPAs currently being executed in the region. The Low Case renewable energy costs are based on an assumption that the costs of renewable generating projects will, as expected, continue to decline and the CCE would, over time, layer in PPAs sourced to the lower cost renewable resources that will be developed over the next five to ten years. The High Case renewable energy costs are based on an assumption that the CCE is not able to secure PPAs sourced to relatively new and lower cost renewable resources but, rather, signs PPAs sourced to older renewable resources with higher costs. The renewable costs in this case reflect the costs of renewable resources that were developed three to five years or more ago.

The 20-year levelized costs of each portfolio has been calculated using the range of resource costs shown above. The base case costs are depicted by the black dots in Exhibit 36, while the range projected between the High Case and the Low Case are depicted by the blue bar.

**Exhibit 36**
**Sensitivity of Portfolio 20-year Levelized Costs $/kWh**




The 100% Renewable portfolio, which relies on the most renewable energy purchases to serve retail load, has the highest projected costs that range from a low of $0.060/kWh to a high of $0.0105/kWh. There is a low likelihood that renewable project costs would increase to the point that 20-year levelized costs of renewable purchases is near $0.0100/kWh. It is far more likely that decreases in solar equipment costs on a $/watt basis will continue. The 20-year levelized costs associated with the renewable PPA alternative pricing discussed in the "Power Supply Strategy and Costs" fall below the black dots and within the blue bars shown above in Exhibit 36.

While renewable energy costs continue to decline, the potential for market PPA prices to increase could be material. Wholesale market prices are dependent on many factors, the most notable of which is natural gas price. Natural gas prices are at historic lows, and because natural gas-fired resources are often the marginal resource in the market, wholesale market prices have followed. Natural gas prices are subject to a variety of local, national and international forces that could have a large impact on the current marketplace. For example, increased regulation in the natural gas industry with respect to the deployment of fracking technology could cause decreases in natural gas supplies and commensurate increases in natural gas prices. Additionally, increased costs associated with carbon taxes and/or carbon cap and trade programs could also cause upward pressure on wholesale market prices.

## SDG&E RPS Portfolio

There are several factors that may impact the share of renewable energy in SDG&E's portfolio over the next decade. Customers departing SDG&E for CCE service throughout SDG&E territory would have the effect of shrinking SDG&E's load, thereby increasing the share of renewables made up by SDG&E's current RPS contracts. Finally, SDG&E could further strive to compete with CCEs in terms of the environmental impact of its power portfolio. In combination, these forces could drive up the share of renewable energy in SDG&E's power mix to match or exceed the CCE's planned power mix. To mitigate this risk, the CCE would have the option to acquire more renewable energy in response to changes in SDG&E's portfolio.

## Availability of Renewable and GHG-Free Resources

Often one of the goals of a CCE is to offer power products that are cleaner than those provided by the IOU. All of the portfolios developed for this Study are modeled at 80% to 100% GHG-free. As such, they include more renewable resources and exceed the share of GHG-free resources in SDG&E's power supply portfolio, which is in the 40% to 50% range.

SDG&E does offer additional renewable choice to customers. EcoChoice allows the customer to sign up for "50% to 100% renewable power" as shown in Exhibit 37.[45] This program is currently closed to commercial customers. EcoChoice has a minimum 1-year enrollment term and charges an exit fee if the customer decides to cancel participation. EcoChoice currently results in a discount off SDG&E's standard rate, because new renewable resources are cheaper than the existing resources committed to by SDG&E. However, the EcoChoice customer will have to pay the PCIA as would CCE customers.

**Exhibit 37**
**EcoChoice Rates (Updated 01/01/2018)**

| Rate Component | Residential ($/kWh) | Small Commercial ($/kWh) | M/L Commercial and Industrial ($/kWh) | Agriculture ($/kWh) | Street Lighting ($/kWh) |
|---|---|---|---|---|---|
| Renewable Power Rate & Program Costs & Transmission | 0.07763 | 0.07763 | 0.07763 | 0.07763 | 0.07763 |
| SDG&E's Average Commodity Cost Adjustment | (0.10138) | (0.09934) | (0.09943) | (0.08293) | (0.06691) |
| **EcoChoice Differential** | **(0.02375)** | **(0.02171)** | **(0.02180)** | **(0.00530)** | **0.01072** |
| PCIA | 0.02267 | 0.02326 | 0.01810 | 0.01282 | 0.00000 |
| **Total Cost** | **(0.00108)** | **0.00155** | **(0.00370)** | **0.00752** | **0.01072** |

For residential customers, the discount per kWh for participating in EcoChoice is $0.02375 per kWh. However, after applying the PCIA, this discount is reduced to $0.00108 per kWh. The

[45] https://www.sdge.com/residential/savings-center/solar-power-renewable-energy/ecochoice

results for SDG&E's EcoChoice program over time are anticipated to be similar to the estimated cost for the 100% renewable product from the CCE because any PCIA changes will impact both the CCE and the EcoChoice programs. While the current estimate for the 80% renewable program indicates that the cost will be 2% below SDG&E standard generation rate for all customers, the 100% renewable program is at parity with the standard SDG&E rate. Changes in the PCIA will impact the EcoChoice program and likely result in EcoChoice rates that are above SDG&E rates for ***all*** rate classes.

SDG&E's EcoShare program allows the customer to contract directly with a renewable project developer and purchase the rights to a portion of the output from a new local renewable generating facility. Customers participating in EcoShare will receive a credit on their SDG&E bill reflecting the amount of renewable energy purchased through the developer. In addition, the customer pays the PCIA and other program costs, such as the administrative costs.

The primary risk associated with a high renewable resource strategy is lack of sufficient renewable resources at prices that would keep the CCE competitive with SDG&E. The current market has sufficient renewable resources available. Utilities that submit requests for renewable power supply receive bids that far exceed the requested amounts at prices that are very competitive to non-renewable market resources. As RPS requirements and the share of renewable resources in CCE portfolios are increasing, competition for renewable resources could increase. However, it is important to note that the CCE movement does not change the total load. Rather, the renewable resource timeline may just have accelerated until targets have been reached. Increased competition would result in increased prices once supply cannot meet the demand, resulting in increased development of renewable resources. In addition, the CCEs would have the opportunity to aid in the development of renewable resources by fostering local resource development.

## Financial Risks

Starting a new venture carries financial risks that will have to be considered and mitigated before proceeding with a CCE. Depending on the organization structure, a third-party may take on the financial obligations of the CCE. These include establishing start-up financing, working capital funding such as lines of credit, and entering into contracts with suppliers and consultants. Other cities and counties have protected their General Funds by establishing JPAs or lockbox arrangements with vendors.

The Partner cities could manage many of the financial risks associated with the uncertainty surrounding a CCE start-up. While the goal is to provide clean power competitively with SDG&E, the most important consideration to the third-party financer is that the CCE can increase rates if needed to ensure sufficient revenues are collected to meet costs. In addition, the CCE can plan carefully by minimizing staff initially and only growing as fast as the size of the CCE can support, thus minimizing the fixed costs of operating the CCE.

The Partners' CCE would need to manage the financial risk associated with power supply costs by managing power market and load exposure through prudent hedging and power portfolio management. In addition, the establishment of rate stabilization reserves and sufficient working capital can mitigate financial risks to the third-party financer and to customers. The success of existing CCEs in managing the financial challenges of a CCE start-up and setting rates that are competitive with the SDG&E and the other IOUs can be a valuable guide for the Partners' CCE.

## Loads and Customer Participation Rates

The Study bases the load forecasts on expected load growth, load profiles, and participation rates. In order to evaluate the potential impact of varying loads, low, medium, and high load forecasts have been developed for the sensitivity analysis.

Another assumption that can impact the costs of the CCE is the overall CCE customer participation rates. This Study uses a conservative participation rate of 95% for residential customers and 85% for non-residential customers as its base case. A higher participation rate, such as has been experienced by all of California's operating CCEs to date, would increase energy sales relative to the base case and decrease the fixed costs paid by each customer. On the other hand, a reduced participation rate would increase the fixed costs to the CCE Partners. For reference, recent CCEs have experienced participation rates in the 90-97% range.

Sensitivity to changes in projected loads has been tested for the high and low load forecast scenarios. For the sensitivity analysis, the high case assumes an additional 5% participation rate for non-residential customers, while the low case assumes the participation rate is reduced by 10% for all customers. The low case assumes a 0% growth in energy and customers after 2019, while the high scenario assumes a 1% growth in energy and customers.

The experience of existing CCEs suggest that only a small number of customers opt-out. For example, PCE has an opt-out rate of 2%, while CPA has a current opt-out rate of 0.7%. Once a CCE is operating, the number of customers switching back to the incumbent IOU have also been less than 5%. In order to mitigate the potential switching of customers, it would be important for the CCE to implement prudent power supply strategies to address potential load swings from changes in participation and weather uncertainty, plus establish a rate stabilization fund. Keeping rates low as well as providing excellent customer service would lead to strong customer retention.

## Sensitivity Results

Exhibit 38 provides the results of the sensitivity analysis for the SDG&E Equivalent Renewable Portfolio (Base Case), which is the most likely portfolio for the CCE to pursue initially given its goals.

**Exhibit 38 Base Case Portfolio – Bundled Rates ($/kWh)**
**10-Year Levelized Average System Rate**

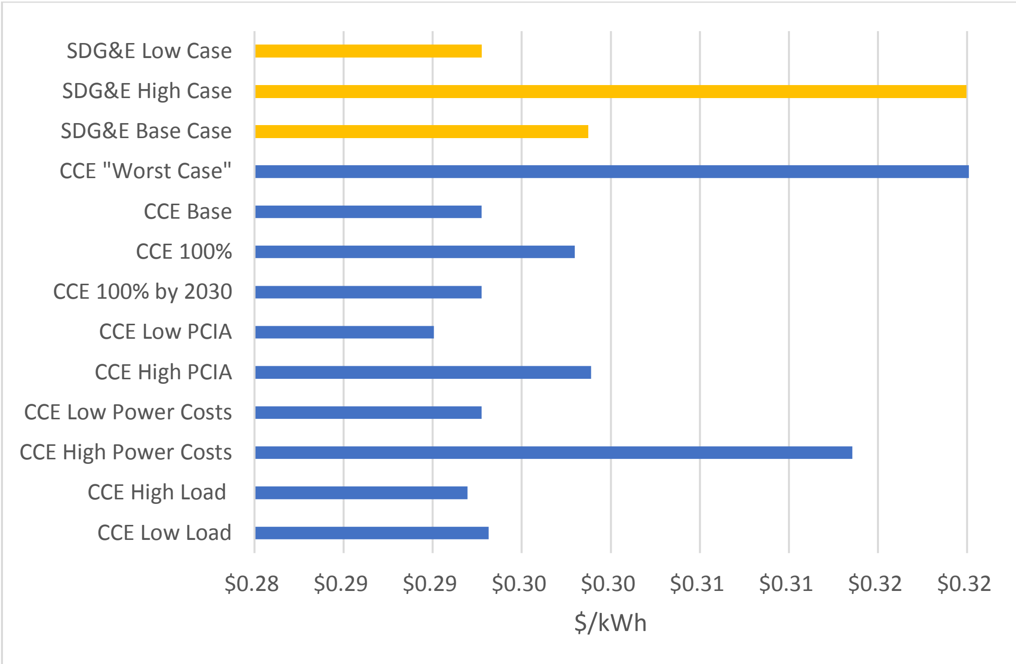



Exhibit 38 provides a comparison of the average system rate under several scenarios. This sensitivity shows that it is a significant risk to the CCE if the CCEs power costs increase based on the high-power cost scenario without any offsetting PCIA benefits. The CCE's rates could also be higher than SDG&E's under a "Worst Case" scenario. This scenario could arise when the CCE does not achieve sufficient customer participation, CCE power supply costs are high, and SDG&E charges a high PCIA. The average system rates associated with the renewable PPA alternative pricing discussed in the "Power Supply Strategy and Costs" fall between the base cases and low power cost cases shown above in Exhibit 38.

Wholesale market prices for natural gas/electricity are currently at all-time lows. The probability of these market prices decreasing significantly from current levels is low. In addition, the CCE would need to manage its supply portfolio so that it is not exposed to unmanageable risks associated with power costs.

While the CCE would not be able to impact SDG&E's generation rates, the CCE does have the opportunity to monitor and actively opine on the costs and methodology used to allocated non-bypassable costs to CCEs in SDG&E's service area, including the PCIA. Given recent history, this task would be shared with other CCEs and is an important and time-consuming task that can mitigate the impact on the CCE's costs. SDG&E's PCIA is at a historic high; however, the design of the PCIA implies that the PCIA will decrease over time as SDG&E's high-cost contracts expire and market prices increase.

This Study assumes a relatively high customer opt-out percentage (15% for non-residential customers) compared to the more modest opt-out rates experienced by California's actively operating CCEs, which is closer to 5% overall. While there is a possibility that the Partners' CCE does not reach the projected participation rates, careful monitoring and planning can reduce the potential impact of low loads through flexible power supply contracts and regular monitoring of administrative and general expenses.

The CCE should also consider implementing a rate stabilization fund so that short-term events that result in lower SDG&E rates compared with the CCE rates can be mitigated with reserves rather than by rate increases. Reserves would help the CCE remain competitive and would provide rate stabilization for customers.

# CCE Governance Options

One indicator of the viability of a CCE for the Partners is the number of Various options for CCE operations for each of the cities that participated in this Study are described below. The following criteria are used to describe strengths and weaknesses of each option: Financial Viability, Governance, Local Control, and Other Attributes.

1. Form a Joint Powers Authority (JPA) with Each of the Partners Joining

   - Financial Viability: This Study shows that a 4-member JPA is financially viable.
   - Governance: Under a JPA, likely each city would be a voting board member. Having a limited number of board members keeps governance nimble and local/regional control focused.
   - Local Control: Since the Partners have similar climate action goals, and collaborated on this Study for similar purposes, decisions around the CCE's operations should be less complicated. Decisions about wholesale power portfolio, rate designs, local distributed generation, and customer clean energy programs should be easier to make.
   - Other Attributes: A JPA of this size is ideal for allowing other San Diego County cities that create their own CCEs to join. Consideration of consistent goals, local programs and operations design should be considered for new CCE cities. Operational savings on non-power supply costs (administration, legal, regulatory, and other services) would likely occur. A JPA provides clear financial protection of cities' general funds from CCE obligations. A JPA could apply to the CPUC for energy efficiency program funds on behalf of the cities.

2. Each City Forms Individual CCE

   - Financial Viability: This is likely viable for each city except Del Mar. EES has analyzed this option and has financial pro-forma results for this including combinations of cities operating together under a smaller JPA.
   - Governance: A single or smaller JPA creates less complicated governance.
   - Local Control: Decision-making is more locally focused.
   - Other Attributes: Solana Beach, Pico Rivera, San Jacinto, and King City are examples of smaller city CCEs that are operating independently; although Pico Rivera and San Jacinto participate in the California Choice Energy Authority (described below) to share non-power costs with other individual city CCEs. Except for Del Mar, individual city CCEs are likely feasible but net revenue margins will be smaller without sharing non-power supply costs with others. Operating a city CCE requires special care to protect the city's general fund from CCE obligations. Individual city CCEs may apply to the CPUC for energy efficiency funding but the amount will be less than a CCE JPA.

3. The Partners Join Another CCE

- Financial Viability: This option would be financially viable and would benefit the net revenue margins for the larger CCE organization.
- Governance: Governance would be more complicated, especially if the Partners join a CCE JPA with many members. However, there are CCEs that operate with many members across contiguous and non-contiguous borders (Clean Power Alliance of Southern CA, Marin Clean Energy, Sonoma Clean Power) despite having large governing boards.
- Local Control: Local decision-making on operations (power portfolio contents, rates, local generation, customer programs) would be diminished, especially under a CCE JPA with many members (e.g., 20-30 or more). Boards of these types of JPAs must approve operations policies and program decisions that could apply across differing communities.
- Other Attributes: Net revenue margins for the organization as a whole benefit from large memberships. How those revenues are utilized to benefit members must be determined by many cities, likely with differing local goals regarding CCE operations. A larger JPA of CCEs could apply for larger amounts energy efficiency funds but the design of the programs becomes more complicated.

The cities could conceivably join the already operating Solana Beach CCE. Solana is a fraction of the size of the Partners in terms of load, and this may create complications in negotiating the roles of each of the cities, sharing of revenues and costs, and other decision-making issues.

4. The Partners Join a JPA of Individual CCEs or Create a San Diego Region JPA of Individual CCEs

- Financial Viability: Any group of CCEs is more financially viable than operating individually.
- Governance: The California Choice Energy Authority (CCEA) is a JPA of individual city CCEs (currently members are Lancaster, Pico Rivera, San Jacinto, and Palm Desert – they have 6 other cities in process of joining them including a city in Tulare County). Individual cities need to adopt resolutions to become a CCE, then they can join CCEA. CCEA provides centralized services such as: power procurement, power scheduling and dispatching, bill data management and regulatory/legal services. Since each city is a CCE, decisions on CCE operations are made by each CCE. The Partners could also create a CCEA-type JPA for San Diego-region CCEs and provide similar, centralized services and benefits.
- Local Control: CCEs that join CCEA (or create a San Diego-region similar organization) retain local control over CCE operations (power portfolio mix, rates, local generation and programs) and will see net revenue benefits by sharing centralized services. However, the details of how these shared services are utilized and paid for need to be determined (in the case of CCEA) and developed (in the case of a San Diego-region effort).
- Other Attributes: Creating a San Diego-region JPA of CCEs makes it easier for San Diego-region cities to become a CCE in that acquiring start-up and operational services support would already be established under the JPA. Each city CCE in the JPA could apply for energy efficiency funding at the CPUC.

## Recommendation

As the Partners move towards CCE adoption by their governing organizations, or after the cities approve creating a CCE, they should further investigate each of these options. EES recommends that the cities further discuss the options among themselves to more clearly understand all of the pros and cons. The cities should develop a more detailed assessment of the options of joining existing organizations or developing new, local/regional organizations. The cities could develop a solicitation to distribute to existing CCE organizations to acquire information about costs and other requirements for joining these organizations. That information should then be compared to potential costs and requirements of creating a new, local/regional CCE organization. If joining another CCE is the preferred option for the Partners, a request for proposal (RFP) should be issued to each potential existing CCE to define the terms of joining an existing CCE.

This Study evaluates the feasibility of operating a CCE under the JPA model with the four Partner cities. The financial sensitivity analysis provided in Appendix H also provides feasibility results for each Partner city operating their own CCE. If the Partners join an existing JPA, the start-up activities are simpler as the organization is already operating and programs have been developed. However, the overall governance issues would have to be established prior to the cities joining the existing CCE.

## CCE Organizational Options

If the Partners operate as a JPA there are several staffing options available. One option would be to operate the CCE with minimal staff, such as a General Manager, Power Supply Manager and a Customer Service Manager, to oversee consultants that would perform all necessary tasks. Another option is to minimize the use of outside consultants and hire sufficient staff in-house to manage all necessary tasks. Most operating CCEs have started with minimal staffing and then transitioned over time to additional staff in-house. A third option is to have an independent third-party completely operate the CCE.

For this Study, it is assumed that the Partners would operate a CCE with limited staff supported by consultants experienced in power procurement, data management and utility operations. If the Partners decide to transition some administrative and operational responsibilities to internally staffed positions, the CCE could reach a full-time staff of approximately 11 employees to perform its responsibilities, primarily related to program and contract management, legal and regulatory, finance and accounting, energy efficiency, marketing and customer service. Technical functions associated with managing and scheduling power suppliers and those related to retail customer billings would likely still be performed by an experienced third-party consultant.

# Conclusions and Recommendations

## Rate Conclusions

The first impact associated with forming the Partners' CCE would be lower electricity bills for CCE customers. CCE customers should see no obvious changes in electric service other than the lower price and potentially more renewable power procurement, depending on the CCE's goals. Customers would pay the power supply charges set by the CCE and no longer pay the costs of SDG&E power supply but would still pay the costs of SDG&E distribution.

Given this Study's findings, the CCE's rate setting can establish a goal of providing rates that are equal to or lower than the equivalent rates offered by SDG&E even under the 100% Renewable by 2030 portfolio. The projected CCE and SDG&E rates are illustrated in Exhibit 39.

**Exhibit 39**
**Bundled Rate Comparison by Customer Class**
**$/kWh**

| Rate Class | 2021 SDG&E Bundled Rate* | SDG&E Renewable Equivalent Bundled Rate | 100% by 2030 Bundled Rate | 100% Renewable Bundled Rate |
|---|---|---|---|---|
| Residential | 0.3494 | 0.3480 | 0.3480 | 0.3494 |
| Small Commercial | 0.2233 | 0.2317 | 0.2317 | 0.2233 |
| Medium Commercial | 0.2303 | 0.2203 | 0.2203 | 0.2303 |
| Street Lights | 0.2388 | 0.2390 | 0.2390 | 0.2388 |
| Agriculture | 0.1322 | 0.1325 | 0.1325 | 0.1322 |
| **Total** | 0.2854 | 0.2797 | 0.2797 | 0.2854 |
| **Initial Rate Savings in 2021 from SDG&E Bundled Rate** | | **2.00%** | **2.00%** | **0.00%** |

*SDG&E bundled average rate projected based on SDG&E's 2019 Rates.

Once the CCE gives notice to SDG&E that it will commence service, the CCE customers will not be responsible for costs associated with SDG&E's future electricity procurement contracts or power plant investments.[46] This is an advantage to the CCE customers as they would then have local control of power supply costs through the CCE.

[46] CCAs may be liable for a share of unbundled stranded costs from new generation but would then receive associated Resource Adequacy credits.

## Renewable Energy Conclusions

A second consequence of forming a CCE would be an increase in the proportion of energy generated and supplied by renewable resources. The Study includes procurement of renewable energy sufficient to meet 50% or more of the CCE's electricity needs (initially). The majority of this renewable energy would be met by new renewable resources over time. By 2030, SDG&E must procure a minimum of 60% of its customers' annual electricity usage from renewable resources due to the State Renewable Portfolio Standard and the Energy Action Plan requirements of the CPUC. The CCE can decide whether to follow the same renewable goals or to implement more aggressive targets.

## Energy Efficiency Conclusions

A third consequence of forming a CCE would be an increase in energy efficiency program investments and activities. The existing energy efficiency programs administered by SDG&E are not expected to change as a result of forming a CCE. The CCE customers would continue to pay the public goods charges to SDG&E which funds energy efficiency programs for all customers, regardless of supplier. The energy efficiency programs ultimately planned for the CCE would be in addition to the level of investment that would continue in the absence of a CCE. Thus, the CCE has the potential for increased energy investment and savings with an attendant further reduction in emissions due to expanded energy efficiency programs.

## Economic Development Conclusions

The fourth consequence of forming a CCE would be enhanced local economic development. The analyses contained in this Study has focused primarily on the direct effects of this formation. However, in addition to direct effects, indirect economic effects are also anticipated. The indirect effects of creating a CCE include the effects of increased local investments, increased disposable income due to bill savings, and improved environmental and health conditions.

Exhibit 40 shows the effects $9 million in electric bill savings could have in San Diego County. The $9 million rate savings represents the estimated (maximum) bill savings per year achievable by the CCE once in full operation. It is estimated that the electric bill savings could create approximately 109 additional jobs in the County with over $5.4 million in labor income. It is also projected that the total value added could be approximately $7.7 million and output close to $13 million.

| Exhibit 40<br>$9 Million Rate Savings Effects on the San Diego County Economy[1] | | | | |
|---|---|---|---|---|
| **Impact Type** | **Employment Jobs** | **Labor Income** | **Total Value Added** | **Output** |
| Direct Effect | 50.7 | $2,473,000 | $2,508,000 | $4,613,000 |
| Indirect Effect | 10.7 | $641,000 | $1,039,000 | $1,740,000 |
| Induced Effect | 47.4 | $2,273,000 | $4,146,000 | $6,712,000 |
| **Total Effect** | 108.8 | $5,387,000 | $7,694,000 | $13,065,000 |

[1]Full impacts to San Diego County are estimated, it can be expected that a large share of these impacts would be realized within the 4 jurisdictions.

These savings are based on the economic assumption that households would spend some share of the increased disposable income on more goods and services. This increased spending on goods and services would then lead to producers either increasing the wages of their current employees or hiring additional employees to handle the increased demand. This in turn would give the employees a larger disposable income which they spend on goods and services and thus repeating the cycle of increased demand.

## Greenhouse Gas (GHG) Emissions Conclusions

A fifth consequence of forming a CCE may be reduced GHG emissions. The amount of renewable power in SDG&E's power supply portfolio is 43% and will rise to 60% by 2030. Based on power supply strategy described previously, the estimated GHG emission reductions are forecast to range from zero to 36,000 tons $CO_2$e per year by 2030 assuming a 60% RPS target is achieved. The baseline for comparison is the SDG&E's portfolio resource mix versus the potential CCE resource mixes. Exhibit 41 details these reductions.

| Exhibit 41<br>Comparison of Average Annual GHG Emissions from Electricity, by Resource Portfolio (2021-2030) | | | | |
|---|---|---|---|---|
| | **SDG&E Equivalent Renewable Portfolio** | **100% Renewable by 2030** | **100% Renewable** | **SDG&E** |
| Avg./GHG Share | 80% | 89% | 100% | 60% |
| Avg. Emissions (Metric Tons CO2) | 109,000 | 61,000 | - | 218,000 |
| Difference SDG&E 50% Portfolio (Metric Tons CO2) | 109,000 | 157,000 | 218,000 | |

## Findings and Conclusions

Based on the analysis conducted in this Study, the following findings and conclusions are made:

- The formation of a CCE is financially feasible and could yield considerable benefits for all participating residents and businesses.

- Financial benefits include electric retail rates that are 2% lower compared with SDG&E rates.
- Benefits are also achieved through local decision-making about power supply, rates and customer programs. Specific programs could include economic development incentives, and targeted energy efficiency and demand response programs. CCE start-up costs could be fully recovered within the first three years of CCE operations.
- After this cost recovery, revenues that exceed costs could be used to finance a rate stabilization fund, new local renewable resources, economic development projects and/or lower customer electric rates.
- The sensitivity analysis shows that the ranges of prices for different market conditions will for the most part not negatively impact CCE rates compared to SDG&E rates. Where negative impacts may exist, those risks can be mitigated
- The CCE could be a means to achieve local control of energy supply, and for cities to meet their respective Climate Action Plan (CAP) goals.
- Local electric rate savings are expected to stimulate economic development.

The positive impacts on the Partner cities and their citizens of forming a CCE suggest that CCE implementation should be considered with the following next steps: consideration of Joint Powers Authority or other governance options, Business Plan development, and Implementation Plan development. No likely combination of sensitivities would change this recommendation based on the detailed analysis contained in the balance of this report.

## Recommendations

Based on the Study results, and recent CCE experience, the following recommendations are made pursuant of CCE formation:

- The CCE should initially contract with a third party with the necessary experience (proven track record, longevity and financial capacity) to perform most of the CCE's portfolio power supply operation requirements. This would include the procurement of energy and ancillary services, scheduling coordinator services, and day-ahead and real-time trading.
- The Partners' CCE should approve and adopt a set of protocols that would serve as the risk management tools for the CCE and any third-party involved in the CCE portfolio operations. Protocols would define risk management policies and procedures, and a process for ensuring compliance throughout the CCE. During the initial start-up period, the chosen electric suppliers would bear the majority of risks and be responsible for their management. The protocols that cover electricity procurement activities should be developed before operations begin.
- The CCE should be flexible in its approach to obtaining power supply resources necessary to meet load requirements.
- Additionally, it is recommended that the Partners engage with a portfolio manager or schedule coordinator, who has expertise in risk management and would work with the CCE to design a comprehensive risk management strategy for long-term operations.

## Summary

This Study concludes that the formation of a CCE in the Partner cities is financially feasible and could yield considerable benefits for all participating residents and businesses. These benefits could include 2% lower rates for electricity, although higher rate reductions are possible. The positive impacts on the Partner cities and their inhabitants of forming a CCE suggest that this effort should be considered. No likely combination of sensitivities or launch schedules would change this recommendation based on a detailed analysis of currently available data.

# Appendix A – Projected Schedule

| | | | 2019 | | | | | | | | | | | | 2020 | | | | | | | | | | | | 2021 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Task | Due Date | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May |
| Feasibility Report | Final Draft Report | 2/1/2019 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | CCA Ad Hoc Council Subcommittee Meeting | 2/15/2019 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Council Presentations | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Carlsbad | 2/15/2019 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Del Mar | 2/15/2019 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Encinitas | 2/15/2019 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Oceanside | 2/15/2019 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Public Workshops | 4/15/2019 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Ordinance | Approval of Ordinance and Resolution to Create CCA | 7/15/2019 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Organizational Setup | Form JPA | 9/1/2019 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Hire Executive Director | 1/1/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Hire Staff | 6/1/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| CPUC Registration | Prepare Implementation Plan | 1/1/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | File Implementation Plan with CPUC | 1/1/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | CPUC completes review of IP | 4/1/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Register with CPUC and submit Bond | 4/1/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | CPUC confirms registration | 5/1/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Resource Adequacy | File Historic Load Data with CPUC/CEC | 3/17/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | File Year-Ahead Load Forecast | 4/20/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Revised Year-Ahead RA Load Forecast | 8/16/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | January Month-Ahead RA Load Forecast Due | 10/15/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Power Procurement | RFP & Contract for Scheduling Coordinator/Portfolio Mng | 7/1/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Develop risk management and procurement plan | 9/1/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Power Purchase and Contracting | 1/1/2021 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Banking & Credit | RFP & Contract for Line of Credit | 8/1/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Finalize financial Plan and Rates | 10/1/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Transaction Testing with SDG&E | 12/1/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Customer Noticing | RFP & Contract for Data Mgmt, Billing, Call Cntr, and Mrkt | 8/1/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Systems Testing with SDG&E | 10/1/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | CCA Website Finalized | 11/1/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Call Center and CRM Operational | 12/1/2020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Pre-Enrollment Notice 1 | 1/1/2021 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Pre-Enrollment Notice 2 | 2/1/2021 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Customer Program Transitions Notice | 3/1/2021 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Program Launch | 4/1/2021 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Post-Enrollment Notice 1 | 4/8/2021 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | Post-Enrollment Notice 2 | 5/10/2021 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Revenues from Operations ($)** | | | | | | | | | | | |
| Electric Sales Revenues for CCE | $0 | $103,669,449 | $122,617,248 | $124,078,350 | $125,132,767 | $130,672,694 | $132,248,045 | $134,277,370 | $137,196,482 | $139,278,617 | $141,386,518 |
| Less Uncollected Accounts | $0 | $156,443 | $210,561 | $211,317 | $219,715 | $229,652 | $237,538 | $245,904 | $254,402 | $263,259 | $272,040 |
| **Total Revenues for CCE** | $0 | $103,513,007 | $122,406,687 | $123,867,032 | $124,913,052 | $130,443,042 | $132,010,508 | $134,031,466 | $136,942,080 | $139,015,358 | $141,114,479 |
| | | | | | | | | | | | |
| **Cost of Operations ($)** | | | | | | | | | | | |
| Cost of Energy | $0 | $71,307,923 | $97,889,416 | $101,399,614 | $105,499,743 | $110,372,197 | $114,270,084 | $118,369,961 | $122,514,027 | $126,840,341 | $131,178,658 |
| | | | | | | | | | | | |
| *Operating & Administrative* | | | | | | | | | | | |
| Billing & Data Management | $0 | $1,725,312 | $2,351,577 | $2,404,605 | $2,458,829 | $2,514,275 | $2,570,972 | $2,628,947 | $2,688,230 | $2,748,850 | $2,810,836 |
| SDG&E Fees | $0 | $389,033 | $390,006 | $390,981 | $391,958 | $392,938 | $393,921 | $394,906 | $395,893 | $396,883 | $397,875 |
| SDG&E Setup and StartUp Fees | $0 | $180,308 | $183,908 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Consulting Services | $426,700 | $1,617,822 | $1,411,407 | $1,439,635 | $1,468,427 | $1,497,796 | $1,527,752 | $1,558,307 | $1,589,473 | $1,621,263 | $1,653,688 |
| Staffing | $389,299 | $2,204,114 | $2,248,196 | $2,293,160 | $2,339,023 | $2,385,804 | $2,433,520 | $2,482,190 | $2,531,834 | $2,582,471 | $2,634,120 |
| General & Administrative expenses | $28,560 | $181,030 | $132,651 | $135,304 | $158,410 | $177,184 | $143,586 | $146,457 | $169,787 | $188,788 | $155,422 |
| Debt Service Payment on Financing | $114,607 | $2,521,353 | $3,208,995 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total O&A Costs | $959,166 | $8,818,973 | $9,926,740 | $6,663,685 | $6,816,648 | $6,967,997 | $7,069,750 | $7,210,808 | $7,375,217 | $7,538,254 | $7,651,941 |
| **Total Cost & Reserves** | $959,166 | $80,126,896 | $107,816,156 | $108,063,299 | $112,316,391 | $117,340,195 | $121,339,834 | $125,580,768 | $129,889,243 | $134,378,595 | $138,830,598 |
| | | | | | | | | | | | |
| **Net Income from Opereations** | ($959,166) | $23,386,111 | $14,590,531 | $15,803,733 | $12,596,662 | $13,102,847 | $10,670,674 | $8,450,698 | $7,052,837 | $4,636,763 | $2,283,880 |
| | | | | | | | | | | | |
| **Cash from Operations and Financing** | | | | | | | | | | | |
| Net Income from Operations | ($959,166) | $23,386,111 | $14,590,531 | $15,803,733 | $12,596,662 | $13,102,847 | $10,670,674 | $8,450,698 | $7,052,837 | $4,636,763 | $2,283,880 |
| Cash from Financing | $2,000,000 | $12,000,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| **Total Cash Available** | $1,040,834 | $35,386,111 | $14,590,531 | $15,803,733 | $12,596,662 | $13,102,847 | $10,670,674 | $8,450,698 | $7,052,837 | $4,636,763 | $2,283,880 |
| | | | | | | | | | | | |
| **Net Income Allocation** | | | | | | | | | | | |
| Reserve Fund Contribution | $1,040,834 | $35,386,111 | ($980,537) | $81,252 | $1,398,277 | $1,651,662 | $1,314,950 | $1,394,280 | $1,416,485 | $1,475,951 | $1,463,672 |
| Working Capital Repayment | $0 | $0 | $0 | $9,133,372 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Cash Available for Other Purposes | $0 | $0 | $15,571,068 | $6,589,109 | $11,198,385 | $11,451,185 | $9,355,724 | $7,056,418 | $5,636,352 | $3,160,811 | $820,208 |
| **Total Cash Outlays** | $0 | $0 | $15,571,068 | $15,722,481 | $11,198,385 | $11,451,185 | $9,355,724 | $7,056,418 | $5,636,352 | $3,160,811 | $820,208 |
| | | | | | | | | | | | |
| **Rate Stabilization Reserve Balance** | **$1,040,834** | **$36,426,945** | **$35,446,407** | **$35,527,660** | **$36,925,937** | **$38,577,598** | **$39,892,548** | **$41,286,828** | **$42,703,313** | **$44,179,264** | **$45,642,936** |
| | | | | | | | | | | | |
| CCA Total Bill | $0 | $333,111,892 | $429,074,010 | $437,061,464 | $445,207,892 | $457,553,598 | $466,078,566 | $474,773,317 | $483,641,397 | $492,686,431 | $501,912,120 |
| SDG&E Total Bill | $0 | $339,910,094 | $437,830,622 | $445,981,086 | $454,293,767 | $466,891,426 | $475,590,374 | $484,462,568 | $493,511,629 | $502,741,256 | $512,155,224 |
| | | | | | | | | | | | |
| Difference | $0 | $6,798,202 | $8,756,612 | $8,919,622 | $9,085,875 | $9,337,829 | $9,511,807 | $9,689,251 | $9,870,233 | $10,054,825 | $10,243,104 |
| Savings | 0% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Revenues from Operations ($)** | | | | | | | | | | | |
| Electric Sales Revenues for CCE | $0 | $103,669,449 | $122,617,248 | $124,078,350 | $125,132,767 | $130,672,694 | $132,248,045 | $134,277,370 | $137,196,482 | $139,278,617 | $141,386,518 |
| Less Uncollected Accounts | $0 | $154,366 | $210,561 | $200,483 | $210,206 | $218,689 | $223,199 | $227,337 | $233,100 | $236,974 | $240,834 |
| **Total Revenues for CCE** | $0 | $103,515,084 | $122,406,687 | $123,877,866 | $124,922,561 | $130,454,005 | $132,024,846 | $134,050,033 | $136,963,382 | $139,041,643 | $141,145,685 |
| | | | | | | | | | | | |
| **Cost of Operations ($)** | | | | | | | | | | | |
| Cost of Energy | $0 | $70,269,484 | $97,889,229 | $95,982,511 | $100,745,330 | $104,890,559 | $107,100,833 | $109,086,432 | $111,863,188 | $113,697,630 | $115,575,738 |
| | | | | | | | | | | | |
| *Operating & Administrative* | | | | | | | | | | | |
| Billing & Data Management | $0 | $1,725,312 | $2,351,577 | $2,404,605 | $2,458,829 | $2,514,275 | $2,570,972 | $2,628,947 | $2,688,230 | $2,748,850 | $2,810,836 |
| SDG&E Fees | $0 | $389,033 | $390,006 | $390,981 | $391,958 | $392,938 | $393,921 | $394,906 | $395,893 | $396,883 | $397,875 |
| SDG&E Setup and StartUp Fees | $0 | $180,308 | $183,908 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Consulting Services | $426,700 | $1,617,822 | $1,411,407 | $1,439,635 | $1,468,427 | $1,497,796 | $1,527,752 | $1,558,307 | $1,589,473 | $1,621,263 | $1,653,688 |
| Staffing | $389,299 | $2,204,114 | $2,248,196 | $2,293,160 | $2,339,023 | $2,385,804 | $2,433,520 | $2,482,190 | $2,531,834 | $2,582,471 | $2,634,120 |
| General & Administrative expenses | $28,560 | $181,030 | $132,651 | $135,304 | $158,410 | $177,184 | $143,586 | $146,457 | $169,787 | $188,788 | $155,422 |
| Debt Service Payment on Financing | $114,607 | $2,521,353 | $3,208,995 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total O&A Costs | $959,166 | $8,818,973 | $9,926,740 | $6,663,685 | $6,816,648 | $6,967,997 | $7,069,750 | $7,210,808 | $7,375,217 | $7,538,254 | $7,651,941 |
| **Total Cost of Operations** | $959,166 | $79,088,457 | $107,815,969 | $102,646,196 | $107,561,977 | $111,858,556 | $114,170,583 | $116,297,239 | $119,238,404 | $121,235,884 | $123,227,679 |
| | | | | | | | | | | | |
| **Net Income from Opereations** | ($959,166) | $24,426,627 | $14,590,718 | $21,231,671 | $17,360,584 | $18,595,449 | $17,854,263 | $17,752,794 | $17,724,978 | $17,805,760 | $17,918,006 |
| | | | | | | | | | | | |
| **Cash from Operations and Financing** | | | | | | | | | | | |
| Net Income from Operations | ($959,166) | $24,426,627 | $14,590,718 | $21,231,671 | $17,360,584 | $18,595,449 | $17,854,263 | $17,752,794 | $17,724,978 | $17,805,760 | $17,918,006 |
| Cash from Financing | $2,000,000 | $12,000,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| **Total Cash Available** | $1,040,834 | $36,426,627 | $14,590,718 | $21,231,671 | $17,360,584 | $18,595,449 | $17,854,263 | $17,752,794 | $17,724,978 | $17,805,760 | $17,918,006 |
| | | | | | | | | | | | |
| **Net Income Allocation** | | | | | | | | | | | |
| Reserve Fund Contribution | $0 | $24,960,851 | $9,444,662 | $0 | $0 | $1,329,070 | $760,118 | $699,175 | $966,958 | $656,706 | $654,837 |
| Working Capital Repayment | $0 | $0 | $0 | $9,133,372 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Cash Available for Other Purposes | $0 | $11,465,776 | $5,146,056 | $12,098,299 | $17,360,584 | $17,266,380 | $17,094,145 | $17,053,619 | $16,758,019 | $17,149,054 | $17,263,169 |
| **Total Cash Outlays** | $0 | $36,426,627 | $14,590,718 | $21,231,671 | $17,360,584 | $18,595,449 | $17,854,263 | $17,752,794 | $17,724,978 | $17,805,760 | $17,918,006 |
| | | | | | | | | | | | |
| **Rate Stabilization Reserve Balance** | **$1,040,834** | **$26,001,684** | **$35,446,346** | **$35,446,346** | **$35,446,346** | **$36,775,416** | **$37,535,534** | **$38,234,709** | **$39,201,667** | **$39,858,373** | **$40,513,210** |
| | | | | | | | | | | | |
| CCA Total Bill | $0 | $333,111,892 | $429,074,010 | $437,061,464 | $445,207,892 | $457,553,598 | $466,078,566 | $474,773,317 | $483,641,397 | $492,686,431 | $501,912,120 |
| SDG&E Total Bill | $0 | $339,910,094 | $437,830,622 | $445,981,086 | $454,293,767 | $466,891,426 | $475,590,374 | $484,462,568 | $493,511,629 | $502,741,256 | $512,155,224 |
| | | | | | | | | | | | |
| Difference | $0 | $6,798,202 | $8,756,612 | $8,919,622 | $9,085,875 | $9,337,829 | $9,511,807 | $9,689,251 | $9,870,233 | $10,054,825 | $10,243,104 |
| Savings | 0% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Infrastructure | | | | | | | | | | | |
| Computers | $20,400 | $36,414 | $0 | $0 | $20,400 | $36,414 | $0 | $0 | $20,400 | $36,414 | $0 |
| Furnishings | $8,160 | $14,566 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Office Space | $0 | $15,606 | $15,918 | $16,236 | $16,561 | $16,892 | $17,230 | $17,575 | $17,926 | $18,285 | $18,651 |
| Utilities and other Office supplies | $0 | $10,404 | $10,612 | $10,824 | $11,041 | $11,262 | $11,487 | $11,717 | $11,951 | $12,190 | $12,434 |
| Miscellaneous | $0 | $104,040 | $106,121 | $108,243 | $110,408 | $112,616 | $114,869 | $117,166 | $119,509 | $121,899 | $124,337 |
| Other | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Other | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Infrastructure Costs | $28,560 | $181,030 | $132,651 | $135,304 | $158,410 | $177,184 | $143,586 | $146,457 | $169,787 | $188,788 | $155,422 |
| | | | | | | | | | | | |
| Consulting | | | | | | | | | | | |
| Legal/Regulatory | $0 | $374,544 | $382,035 | $389,676 | $397,469 | $405,418 | $413,527 | $421,797 | $430,233 | $438,838 | $447,615 |
| Advertising/Communication | $34,000 | $208,080 | $106,121 | $108,243 | $110,408 | $112,616 | $114,869 | $117,166 | $119,509 | $121,899 | $124,337 |
| Human Resources firm | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Technical Consultants | $61,200 | $124,848 | $127,345 | $129,892 | $132,490 | $135,139 | $137,842 | $140,599 | $143,411 | $146,279 | $149,205 |
| Data Management | $0 | $1,725,312 | $2,351,577 | $2,404,605 | $2,458,829 | $2,514,275 | $2,570,972 | $2,628,947 | $2,688,230 | $2,748,850 | $2,810,836 |
| Financial Consulting | $255,000 | $520,200 | $530,604 | $541,216 | $552,040 | $563,081 | $574,343 | $585,830 | $597,546 | $609,497 | $621,687 |
| Accounting Services | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| CalCCA Annual Dues | $0 | $78,030 | $106,121 | $108,243 | $110,408 | $112,616 | $114,869 | $117,166 | $119,509 | $121,899 | $124,337 |
| Other consulting | $76,500 | $312,120 | $159,181 | $162,365 | $165,612 | $168,924 | $172,303 | $175,749 | $179,264 | $182,849 | $186,506 |
| Other | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Other | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total Consulting Costs | $426,700 | $3,343,134 | $3,762,983 | $3,844,239 | $3,927,256 | $4,012,071 | $4,098,724 | $4,187,254 | $4,277,703 | $4,370,112 | $4,464,524 |
| | | | | | | | | | | | |
| Staffing | | | | | | | | | | | |
| Chief Executive Officer | $153,000 | $312,120 | $318,362 | $324,730 | $331,224 | $337,849 | $344,606 | $351,498 | $358,528 | $365,698 | $373,012 |
| General Council & Director of Government Affairs | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Director of Power Resources | $119,337 | $243,447 | $248,316 | $253,282 | $258,348 | $263,515 | $268,785 | $274,160 | $279,644 | $285,237 | $290,941 |
| Regulatory/Legislative Analyst | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Administrative Assistant | $0 | $114,405 | $116,693 | $119,027 | $121,408 | $123,836 | $126,313 | $128,839 | $131,416 | $134,044 | $136,725 |
| Energy Programs Manager | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Director of Administration and Finance | $19,889 | $243,446 | $248,315 | $253,282 | $258,347 | $263,514 | $268,784 | $274,160 | $279,643 | $285,236 | $290,941 |
| Director of Marketing and Public Affairs | $0 | $243,447 | $248,316 | $253,282 | $258,348 | $263,515 | $268,785 | $274,160 | $279,644 | $285,237 | $290,941 |
| Power Supply Compliance Specialist | $0 | $198,030 | $201,990 | $206,030 | $210,151 | $214,354 | $218,641 | $223,014 | $227,474 | $232,023 | $236,664 |
| Power Resource Planning and Program Analyst | $0 | $198,030 | $201,990 | $206,030 | $210,151 | $214,354 | $218,641 | $223,014 | $227,474 | $232,023 | $236,664 |
| Community Outreach Manager | $97,073 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Account Service Manager | $0 | $191,193 | $195,017 | $198,917 | $202,895 | $206,953 | $211,092 | $215,314 | $219,620 | $224,013 | $228,493 |
| Account Representatives | $0 | $114,405 | $116,693 | $119,027 | $121,408 | $123,836 | $126,313 | $128,839 | $131,416 | $134,044 | $136,725 |
| Communication Specialists | $0 | $171,432 | $174,861 | $178,358 | $181,925 | $185,564 | $189,275 | $193,061 | $196,922 | $200,860 | $204,877 |
| Executive Assistant/Council Clerk | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Administrative Analysts | $0 | $174,159 | $177,643 | $181,195 | $184,819 | $188,516 | $192,286 | $196,132 | $200,054 | $204,056 | $208,137 |
| Total Staffing Costs | $389,299 | $2,204,114 | $2,248,196 | $2,293,160 | $2,339,023 | $2,385,804 | $2,433,520 | $2,482,190 | $2,531,834 | $2,582,471 | $2,634,120 |

| | 2020 | 2020 | 2020 | 2020 | 2020 | 2020 | 2020 | 2020 | 2020 | 2020 | 2020 | 2020 | 2021 | 2021 | 2021 | 2021 | 2021 | 2021 | 2021 | 2021 | 2021 | 2021 | 2021 | 2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** |
| | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | **13** | **14** | **15** | **16** | **17** | **18** | **19** | **20** | **21** | **22** | **23** | **24** |
| **Cash Flow** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Revenues** | | | | | | | | | | | | | | | | | | | | | | | | |
| CCA Generation Revenues | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $6,712,627 | $12,410,826 | $12,659,898 | $14,999,321 | $15,076,410 | $14,189,166 | $13,644,920 | $6,824,185 | $7,152,097 |
| CCA PCIA Revenue | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $3,094,032 | $3,204,545 | $3,267,868 | $3,886,106 | $3,900,567 | $3,674,739 | $3,526,735 | $3,159,538 | $3,423,487 |
| **CCA Revenues based on Projected Rates (GEN+PCIA)** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$9,806,659** | **$15,615,371** | **$15,927,766** | **$18,885,426** | **$18,976,978** | **$17,863,905** | **$17,171,655** | **$9,983,723** | **$10,575,584** |
| | | | | | | | | | | | | | | | | | | | | | | | | |
| **Expenses** | | | | | | | | | | | | | | | | | | | | | | | | |
| *Power Supply* | | | | | | | | | | | | | | | | | | | | | | | | |
| Power Procurement | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $6,226,686 | $6,453,445 | $6,754,146 | $9,703,089 | $10,114,481 | $9,219,451 | $8,134,402 | $7,253,374 | $7,807,888 |
| Non-bypassable charges | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $3,094,032 | $3,204,545 | $3,267,868 | $3,886,106 | $3,900,567 | $3,674,739 | $3,526,735 | $3,159,538 | $3,423,487 |
| **Total Power Supply** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$9,320,718** | **$9,657,990** | **$10,022,014** | **$13,589,194** | **$14,015,048** | **$12,894,190** | **$11,661,137** | **$10,412,912** | **$11,231,375** |
| | | | | | | | | | | | | | | | | | | | | | | | | |
| *CCA Program Costs* | | | | | | | | | | | | | | | | | | | | | | | | |
| Data Management | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $192,026 | $192,451 | $193,022 | $192,708 | $192,751 | $192,741 | $192,802 | $192,366 | $184,447 |
| IOU Fees (including Billing) | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $32,484 | $32,556 | $32,653 | $32,600 | $32,607 | $32,605 | $32,615 | $32,542 | $31,202 |
| Consultants | $0 | $0 | $0 | $0 | $0 | $0 | $65,450 | $65,450 | $65,450 | $65,450 | $82,450 | $82,450 | $128,316 | $128,316 | $128,316 | $136,986 | $136,986 | $136,986 | $136,986 | $136,986 | $136,986 | $136,986 | $136,986 | $136,986 |
| Uncollected accounts | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $13,716 | $14,170 | $14,771 | $20,669 | $21,492 | $19,702 | $17,532 | $15,770 | $16,876 |
| Staffing | $0 | $0 | $0 | $0 | $0 | $0 | $61,568 | $61,568 | $61,568 | $61,568 | $61,568 | $81,458 | $183,676 | $183,676 | $183,676 | $183,676 | $183,676 | $183,676 | $183,676 | $183,676 | $183,676 | $183,676 | $183,676 | $183,676 |
| General & Admin | $0 | $0 | $0 | $0 | $0 | $0 | $21,420 | $0 | $0 | $0 | $0 | $7,140 | $61,817 | $10,838 | $10,838 | $10,838 | $10,838 | $10,838 | $10,838 | $10,838 | $10,838 | $10,838 | $10,838 | $10,838 |
| Debt Payment | $0 | $0 | $0 | $0 | $0 | $0 | $19,101 | $19,101 | $19,101 | $19,101 | $19,101 | $19,101 | $38,202 | $38,202 | $38,202 | $267,416 | $267,416 | $267,416 | $267,416 | $267,416 | $267,416 | $267,416 | $267,416 | $267,416 |
| **Total Expenses (excl PCIA)** | **$0** | **$0** | **$0** | **$0** | **$0** | **$0** | **$167,539** | **$146,119** | **$146,119** | **$146,119** | **$163,119** | **$190,149** | **$412,012** | **$361,032** | **$361,032** | **$6,871,802** | **$7,099,087** | **$7,400,486** | **$10,355,273** | **$10,767,495** | **$9,870,674** | **$8,783,465** | **$7,900,601** | **$8,454,882** |

| **Reserve Needs** | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Beginning Balance | 0 | $0 | $0 | $0 | $0 | $0 | $1,000,000 | $832,461 | $686,341 | $540,222 | $394,102 | $230,983 | $1,040,834 | $628,822 | $267,790 | $11,906,758 | $11,069,616 | $4,004,837 | $3,424,658 | $8,236,446 | $10,347,489 | $14,388,365 | $19,403,460 | $24,618,631 |
| Additions | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $6,712,627 | $12,410,826 | $12,659,898 | $14,999,321 | $15,076,410 | $14,189,166 | $13,644,920 |
| Financing | $0 | $0 | $0 | $0 | $0 | $1,000,000 | $0 | $0 | $0 | $0 | $0 | $1,000,000 | $0 | $0 | $12,000,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Working capital repayment | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Reductions | $0 | $0 | $0 | $0 | $0 | $0 | $167,539 | $146,119 | $146,119 | $146,119 | $163,119 | $190,149 | $412,012 | $361,032 | $361,032 | $837,142 | $7,064,779 | $7,292,807 | $7,599,038 | $10,548,854 | $10,958,445 | $10,061,316 | $8,973,995 | $8,084,815 |
| Ending Balance | $0 | $0 | $0 | $0 | $0 | $1,000,000 | $832,461 | $686,341 | $540,222 | $394,102 | $230,983 | $1,040,834 | $628,822 | $267,790 | $11,906,758 | $11,069,616 | $4,004,837 | $3,424,658 | $8,236,446 | $10,347,489 | $14,388,365 | $19,403,460 | $24,618,631 | $30,178,737 |

| **Cash flow** | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Beginning Balance | $0 | $0 | $0 | $0 | $0 | $0 | $1,000,000 | $832,461 | $686,341 | $540,222 | $394,102 | $230,983 | $1,040,834 | $628,822 | $267,790 | $11,906,758 | $11,069,616 | $4,004,837 | $3,424,658 | $8,236,446 | $10,347,489 | $14,388,365 | $19,403,460 | $24,618,631 |
| Additions | | | | | | | | | | | | | | | | | | | | | | | | |
| Revenues | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $6,712,627 | $12,410,826 | $12,659,898 | $14,999,321 | $15,076,410 | $14,189,166 | $13,644,920 |
| Financing | $0 | $0 | $0 | $0 | $0 | $1,000,000 | $0 | $0 | $0 | $0 | $0 | $1,000,000 | $0 | $0 | $12,000,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Reductions including debt service | $0 | $0 | $0 | $0 | $0 | $0 | $167,539 | $146,119 | $146,119 | $146,119 | $163,119 | $190,149 | $412,012 | $361,032 | $361,032 | $837,142 | $7,064,779 | $7,292,807 | $7,599,038 | $10,548,854 | $10,958,445 | $10,061,316 | $8,973,995 | $8,084,815 |
| Ending Balance | $0 | $0 | $0 | $0 | $0 | $1,000,000 | $832,461 | $686,341 | $540,222 | $394,102 | $230,983 | $1,040,834 | $628,822 | $267,790 | $11,906,758 | $11,069,616 | $4,004,837 | $3,424,658 | $8,236,446 | $10,347,489 | $14,388,365 | $19,403,460 | $24,618,631 | $30,178,737 |

# Appendix F – Glossary

**Ancillary Services:** Those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system.

**aMW**: Average annual Megawatt. A unit of energy output over a year that is equal to the energy produced by the continuous operation of one megawatt of capacity over a period of time (8,760 megawatt-hours).

**Baseload Resources:** Base load power generation resources are resources such as coal, nuclear, hydropower, and geothermal heat that are cheapest to operate when they generate approximately the same output every hour.

**Basis Difference (Natural Gas)**: The difference between the price of natural gas at the Henry Hub natural gas distribution point in Erath, Louisiana, which serves as a central pricing point for natural gas futures, and the natural gas price at another hub location (such as for Southern California).

**Buckets**: Buckets 1-3 refer to different types of renewable energy contracts according to the Renewable Portfolio Standards requirements. Bucket 1 are traditional contracts for delivery of electricity directly from a generator within or immediately connected to California. These are the most valuable and make up the majority of the RECS that are required for LSEs to be RPS compliant. Buckets 2 and 3 have different levels of intermediation between the generation and delivery of the energy from the generating resources.

**Bundled Customers**: Electricity customers who receive all their services (transmission, distribution and supply) from the Investor-Owned Utility.

**Bundled and Unbundled Renewable RECs:** Unbundled Renewable Energy Credits (RECs) are those that have been disassociated from the electricity production originally represented and are sold separately from energy. Bundled RECs are delivered with the associated energy.

**California Independent System Operator (CAISO)**: The organization responsible for managing the electricity grid and system reliability within the former service territories of the three California IOUs.

**California Balancing Authority:** A balancing authority is responsible for operating a transmission control area. It matches generation with load and maintains consistent electric frequency of the grid, even during extreme weather conditions or natural disasters. California has 8 balancing authorities. SDG&E is in CAISO.

**California Clean Power (CCP)**: A private company providing wholesale supply and other services to CCEs.

**California Energy Commission (CEC)**: The state regulatory agency with primary responsibility for enforcing the Renewable Portfolio Standards law as well as a number of other, electric-industry related rules and policies.

**California Public Utilities Commission (CPUC)**: The state agency with primary responsibility for regulating IOUs, as well as Direct Access (ESP) and CCE entities.

**Capacity Factor**: The ratio of an electricity generating resource's actual output over a period of time to its potential output if it were possible to operate at full nameplate capacity continuously over the same period. Intermittent renewable resources, like wind and solar, typically have lower capacity factors than traditional fossil fuel plants because the wind and sun do not blow or shine consistently.

**CleanPowerSF**: CCE program serving customers within the City of San Francisco. CleanPowerSF began service to 7,800 "Phase 1" customers in May 2016.

**Climate Zone**: A geographic area with distinct climate patterns necessitating varied energy demands for heating and cooling.

**Coincident Peak**: Demand for electricity among a group of customers that coincides with peak total demand on the system.

**Community Choice Aggregation (CCA)**: Method available through California law to allow cities and Counties to aggregate their citizens and become their electric generation provider.

**Community Choice Energy**: A City, County or Joint Powers Agency procuring wholesale power to supply to retail customers.

**Community Choice Partners**: A private company providing services to CCEs in California.

**Congestion Charges:** When there is transmission congestion, i.e. more users of the transmission path than capacity, the CaISO charges all users of the congested transmission path a "Usage Charge".

**Congestion Revenue Rights (CRRs)**: Financial rights that are allocated to Load Serving Entities to offset differences between the prices where their generation is located and the price that they pay to serve their load. These rights may also be bought and sold through an auction process. CRRs are part of the CAISO market design.

**Demand Side Resources:** Energy efficiency and load management programs that reduce the amount of energy that would otherwise be consumed by a customer of an electric utility.

**Demand Response (DR)**: Electric customers who have a contract to modify their electricity usage in response to requests from a utility or other electric entity. Typically, will be used to lower demand during peak energy periods, but may be used to raise demand during periods of excess supply.

**Direct Access**: Large power consumers which have opted to procure their wholesale supply independently of the IOUs through an Electricity Service Provider.

**EEI (Edison Electric Institute) Agreement**: A commonly used enabling agreement for transacting in wholesale power markets.

**Electric Service Providers (ESP)**: An alternative to traditional utilities. They provide electric services to retail customers in electricity markets that have opened their retail electricity markets to competition. In California the Direct Access program allows large electricity customers to opt-out of utility-supplied power in favor of ESP-provided power. However, there is a cap on the amount of Direct Access load permitted in the state.

**Electric Tariffs**: The rates and terms applied to customers by electric utilities. Typically have different tariffs for different classes of customers and possibly for different supply mixes.

**Enterprise Model**: When a City or County establish a CCE by themselves as an enterprise within the municipal government.

**Federal Tax Incentives**: There are two Federal tax incentive programs. The Investment Tax Credit (ITC) provides payments to solar generators. The Production Tax Credit (PTC) provides payments to wind generators.

**Feed-in Tariff (FIT)**: A tariff that specifies what generators who are connected to the distribution system are paid.

**Firming:** Firm capacity is the amount of energy available for production or transmission which can be (and in many cases must be) guaranteed to be available at a given time. Firm energy refers to the actual energy guaranteed to be available. Firming refers to the financial instrument to change non-firm power to form power.

**Flexible Resource Adequacy:** Flexible capacity need is defined as the quantity of economically dispatched resources needed by the California ISO to manage grid reliability during the greatest three-hour continuous ramp in each month.

**Forward Prices**: Prices for contracts that specify a future delivery date for a commodity or other security. There are active, liquid forward markets for electricity to be delivered at a number of Western electricity trading hubs, including SP15 which corresponds closely to the price location which the City of Davis will pay to supply its load.

**Implied Heat Rate**: A calculation of the day-ahead electric price divided by the day-ahead natural gas price. Implied heat rate is also known as the 'break-even natural gas market heat rate,' because only a natural gas generator with an operating heat rate (measure of unit efficiency) below the implied heat rate value can make money by burning natural gas to generate power. Natural gas plants with a higher operating heat rate cannot make money at the prevailing electricity and natural gas prices.

**Integrated Resource Plan**: A utility's plan for future generation supply needs.

**Investor-Owned Utility (IOU)**: For profit regulated utilities. Within California there are three IOUs - Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric.

**ISDA (International Swaps and Derivatives Association)**: Popular form of bilateral contract to facilitate wholesale electricity trading.

**Joint Powers Agency (JPA)**: A legal entity comprising two or more public entities. The JPA provides a separation of financial and legal responsibility from its member entities.

**Lancaster Choice Energy (LCE)**: A single-jurisdiction CCE serving residents of the City of Lancaster in Southern California. LCE launched service in October 2015 and served 51,000 customers.

**LEAN Energy (Local Energy Aggregation Network)**: A not-for-profit organization dedicated to expanding Community Choice Aggregation nationwide.

**Load Forecast**: A forecast of expected load over some future time horizon. Short-term load forecasts are used to determine what supply sources are needed. Longer-term load forecasts are used for budgeting and long-term resource planning.

**Local Resource Adequacy:** Local requirements are determined based on an annual CAISO study using a 1-10 weather year and an N-1-1 contingency

**Marginal Unit**: An additional unit of power generation to what is currently being produced. At and electric power plant, the cost to produce a marginal unit is used to determine the cost of increasing power generation at that source.

**Marin Clean Energy (MCE)**: The first CCE in California now serving residents and businesses in the Counties of Marin and Napa, and the cities of Richmond, Benicia, El Cerrito, San Pablo, Walnut Creek, and Lafayette.

**Market Redesign and Technology Upgrade (MRTU)**: CAISO's redesigned, nodal (as opposed to zonal) market that went live in April of 2009.

**Net Energy Metering (NEM)**: The program and rates that pertain to electricity customers who also generate electricity, typically from rooftop solar panels.

**Non-bypassable Charges:** Charges applied to all customers receiving service from Investor-Owned Utilities in California, but which are separated into a separate charge for departing load customers, such as Community Choice Aggregation and Direct Access Customers. These charges include charges for the Public Purpose Programs (PPP), Nuclear Decommissioning (ND), California Department of Water Resources Bond (CDWR), Power Charge Indifference Adjustment (PCIA), Energy Cost Recovery Amount (ECRA), Competition Transition Charge (CTC), Cost Allocation Mechanism (CAM).

**Non-Coincident Peak**: Energy demand by a customer during periods that do not coincide with maximum total system load.

**Non-Renewable Power**: Electricity generated from non-renewable sources or a source that does not come with a Renewable Energy Credit (REC).

**On-Bill Repayment (OBR)**: Allows electric customers to pay for financed improvements such as energy efficiency measures through monthly payments on their electricity bills.

**Operate on the Margin**: Operation of a business or resource at the limit of where it is profitable.

**Opt-Out**: Community Choice Aggregation is, by law, an opt-out program. Customers within the borders of a CCE are automatically enrolled within the CCE unless they proactively opt-out of the program.

**Peninsula Clean Energy (PCE):** Community Choice Aggregation program serving residents and businesses of San Mateo County. PCE launched in October of 2016.

**Pricing Nodes:** The ISO wholesale power market prices electricity based on the cost of generating and delivering it from particular grid locations called nodes.

**Power Cost Indifference Adjustment (PCIA)**: A charge applied to customers who leave IOU service to become Direct Access or CCE customers. The charge is meant to compensate the IOU for costs that it has previously incurred to serve those customers.

**Power Purchase Agreement (PPA)**: The standard term for bilateral supply contracts in the electricity industry.

**Portfolio Content Category:** California's RPS program defines all renewable procurement acquired from contracts executed after June 1, 2010 into three portfolio content categories, commonly referred to as "buckets."

**Renewable Energy Credits (RECs)**: The renewable attributes from RPS-qualified resources which must be registered and retired to comply with RPS standards.

**Resource Adequacy (RA)**: The requirement that a Load-Serving Entity own or procure sufficient generating capacity to meet its peak load plus a contingency amount (15% in California) for each month.

**Renewable Portfolio Standard (RPS)**: The state-based requirement to procure a certain percentage of load from RPS-certified renewable resources.

**Scheduling Coordinator**: An entity that is approved to interact directly with CAISO to schedule load and generation. All CAISO participants must be or have an SC. A scheduling coordinator provides day-ahead and real-time power and transmission scheduling services.

**Scheduling Agent**: A person or service that forecasts and monitors short term system load requirements and meets these demands by scheduling power resource to meet that demand.

**Shaping:** Function that facilitate and support the delivery of energy generation to periods when it is needed most.

**Silicon Valley Clean Energy (SVCE):** CCE serving customers in twelve communities within Santa Clara County including the cities of Campbell, Cupertino, Gilroy, Los Altos, Los Altos Hills, Los Gatos, Monte Sereno, Morgan Hill, Mountain View, Saratoga, Sunnyvale, and the County of Santa Clara. As of the date of completion of this Study, SVCE had not yet launched service.

**Sonoma Clean Power (SCP)**: A CCE serving Sonoma County and Sonoma County cities. On December 29$^{th}$, SCP received approval of their implementation plan from the California Public Utilities Commission to extend service into Mendocino County.

**SP15**: Refers to a wholesale electricity pricing hub - South of Path 15 - which roughly corresponds to SCE and SDG&E's service territory. Forward and Day-Ahead power contracts for Northern California typically provide for delivery at SP15. It is not a single location, but an aggregate based on the locations of all the generators in the region.

**Spark Spread**: The theoretical grow margin of a gas-fired power plant from selling a unit of electricity, having bought the fuel required to produce this unit of electricity. All other costs (capital, operation and maintenance, etc.) must be covered from the spark spread.

**Supply Stack**: Refers to the generators within a region, stacked up according to their marginal cost to supply energy. Renewables are on the bottom of the stack and peaking gas generators on the top. Used to provide insights into how the price of electricity is likely to change as the load changes.

**System Resource Adequacy:** System requirements are determined based on each LSEs CEC adjusted forecast plus a 15% planning reserve margin.

**Vintage:** The vintage of CRS applicable to a CCE customer is determined based on when the CCE commits to begin providing generation services to the customer. CCEs may formally commit to become the generation service provider for a group of customers

**Weather Adjusted**: Normalizing energy use data based on differences in the weather during the time of use. For instance, energy use is expected to be higher on extremely hot days when air conditioning is in higher demand than on days with comfortable temperature. Weather adjustment normalizes for this variation.

**Western Electric Coordinating Council (WECC)**: The organization responsible for coordinating planning and operation on the Western electric grid.

**Wholesale Power**: Large amounts of electricity that are bought and sold by utilities and other electric companies in bulk at specific trading hubs. Quantities are measured in MWs, and a standard wholesale contract is for 25 MW for a month during heavy-load or peak hours (7am to 10 pm, Mon-Sat), or light-load or off-peak hours (all the other hours).

**Western States Power Pool (WSPP) Agreement**: Common, standardized enabling agreement to transact in the wholesale power markets.

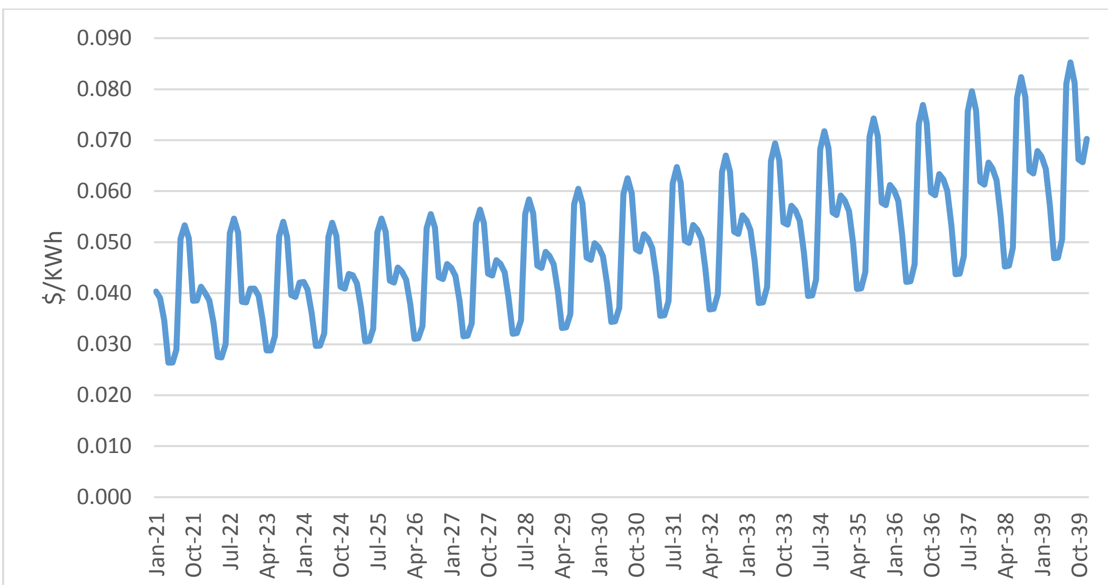
# Appendix G – Power Supply Detail

## Wholesale Market Prices

Market prices for SP15, which is the southern California energy market location, were taken from S&P Global. An adder of $1/MWh was included in the forecast PPA prices to account for potential price differences between SP15 and the pricing nodes at which the CCE would transact.

Figure G-1 below shows forecast monthly southern California wholesale electric market prices. The levelized value of market prices over the 20-year study period is $0.0472/kWh (2018$) assuming a 4% discount rate. Electric market prices peak in the winter and summer when there is large heating and cooling load.

**Figure G-1**
**Forecast Southern California Wholesale Market Prices**




Wholesale power prices have been used to calculate balancing market purchases and sales. When the CCE's loads are greater than its resource capabilities, the CCE's scheduling coordinator would schedule balancing purchases and the CCE would incur balancing market purchase costs. When the CCE's loads are less than its resource capabilities, the CCE's scheduling coordinator would transact balancing sales and the CCE would receive market sales revenue. Balancing market purchases and sales can be transacted on a monthly, daily and hourly pre-schedule basis.

## Ancillary and Congestion Costs

The CCE would pay the CAISO for transmission congestion and ancillary services. Transmission congestion occurs when there is insufficient capacity to meet the demands of all transmission customers. Congestion refers to a shortage of transmission capacity to supply a waiting market and is marked by systems running at full capacity and still being unable to serve the needs of all customers. The transmission system is not allowed to run above its rated capacities. Congestion is managed by the CAISO by charging congestion charges in the day-ahead market. Congestion charges can be managed through the use of Congestion Revenue Rights (CRR). CRRs are financial instruments made available through a CRR allocation, a CRR auction, and a secondary registration system. CRR holders manage variability in congestion costs. The CCE's congestion charges would depend on the transmission paths used to bring resources to load. As such, the location of generating resources used to serve the CCE load would impact these congestion costs.

The Grid Management Charge (GMC) is the vehicle through which the CAISO recovers its administrative and capital costs from the entities that utilize the CAISO's services. Based on a survey of GMC costs currently paid by CAISO participants, the CCE's GMC costs are expected to be near $0.5/MWh.

The CAISO performs annual studies to identify the minimum local resource capacity required in each local area to meet established reliability criteria. Load serving entities receive a proportional allocation of the minimum required local resource capacity by transmission access charge area and submit resource adequacy plans to show that they have procured the necessary capacity. Depending on these results of the annual studies, there may be costs associated with local capacity requirements for the CCE.

Because generation is delivered as it is produced and, particularly with respect to renewables which can be intermittent, deliveries need to be firmed using ancillary services to meet the CCE's load requirements. Ancillary services would need to be purchased from the CAISO. Regulation and operating reserves are described below.

- *Regulation Service:* Regulation service is necessary to provide for the continuous balancing of resources with load and for maintaining scheduled interconnection frequency at 60 cycles per second (60 Hertz). Regulation and frequency response service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load.

- *Operating Reserves - Spinning Reserve Service:* Spinning reserve service is needed to serve load immediately in the event of a system contingency. Spinning reserve service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service.

- *Operating Reserves – Non-Spinning Reserve Service:* Non-spinning reserve service is available within a short period of time to serve load in the event of a system contingency. Non-spinning reserve service may be provided by generating units that are on-line but not providing power, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service.

Based on a survey of ancillary service costs currently paid by CAISO participants, the CCE's ancillary service costs are estimated to be near \$0.003/kWh. The Study's base case assumes ancillary service costs are \$0.003/kWh in 2020, escalating by 20% annually thereafter. Serving a greater percentage of load, 60% to 100% as is modeled in The Study, with renewables would likely result in increased grid congestion and higher ancillary service costs. The scenarios included in this Study as shown below in Exhibit G-2.

**Exhibit G-2**
**Base Case Ancillary Service Costs in Resource Portfolios**

| Portfolio | 2020 Ancillary Service Costs (\$/kWh) | Annual Escalation Factor |
|---|---|---|
| 1- SDG&E Equivalent | \$0.003 | 20% |
| 2- 100% renewable by 2030 | \$0.003 | 20% |
| 3- 100% Renewable | \$0.003 | 20% |

## Scheduling Coordinator Services

A scheduling coordinator provides day-ahead and real-time power and transmission scheduling services. Scheduling coordinators bear the responsibility for accurate and timely load forecasting and resource scheduling including wholesale power purchases and sales required to maintain hourly load/resource balances. A scheduling coordinator needs to provide the marketing expertise and analytical tools required to optimally dispatch the CCE's surplus resources on a monthly, daily, and hourly basis.

The CCE's scheduling coordinator would need to forecast the CCE's hourly loads as well as the CCE's hourly resources including shares of any hydro, wind, solar, and other resources in which the CCE is a participant/purchaser. Forecasting the output of hydro, wind, and solar projects involves more variables than forecasting loads. Scheduling coordinators already have models set up to accurately forecast hourly hydro, wind, and solar generation. Accurate load and resource forecasting would be a key element in assuring the Partners' CCE power supply costs are minimized.

A scheduling coordinator also provides monthly checkout and after-the-fact reconciliation services. This requires scheduling coordinators to agree on the amount of energy purchased and/or sold and the purchase costs and/or sales revenue associated with each counterparty with which the CCE transacted in a given month.

A scheduling coordinator provides day-ahead and real-time power and transmission scheduling services. Scheduling coordinators bear the responsibility for accurate and timely load forecasting and resource scheduling including wholesale power purchases and sales required to maintain hourly load/resource balances. A scheduling coordinator needs to provide the marketing expertise and analytical tools required to optimally dispatch the CCE's surplus and deficit resources on a monthly, daily and hourly basis.

Inside each hour, the CAISO Energy Imbalance Market (EIM) takes over load/resource balancing duties. The EIM automatically balances loads and resources every fifteen minutes and dispatches least-cost resources every 5-minutes. The EIM allows balancing authorities to share reserves, and more reliably and efficiently integrate renewable resources across a larger geographic region.

Within a given hour, metered energy (i.e., actual usage) may differ from supplied power due to hourly variations in resource output or unexpected load deviations. Deviations between metered energy and supplied power are accounted for by the EIM. The imbalance market is used to resolve imbalances between supply and demand. The EIM deals only with energy, not ancillary services or reserves.

The EIM optimally dispatches participating resources to maintain load/resource balance in real-time. The EIM uses the CAISO's real-time market, which uses Security Constrained Economic Dispatch (SCED). SCED finds the lowest cost generation to serve the load taking into account operational constraints such as limits on generators or transmission facilities. The five-minute market automatically procures generation needed to meet future imbalances. The purpose of the five-minute market is to meet the very short-term load forecast. Dispatch instructions are effectuated through the Automated Dispatch System (ADS).

The CAISO is the market operator and runs and settles EIM transactions. The CCE's scheduling coordinator would submit the CCE's load and resource information to the market operator. EIM processes are running continuously for every fifteen-minute and five-minute interval, producing dispatch instructions and prices.

Participating resource scheduling coordinators submit energy bids to let the market operator know that they are available to participate in the real-time market to help resolve energy imbalances. Resource schedulers may also submit an energy bid to declare that resources will increase or decrease generation if a certain price is struck. An energy bid is comprised of a megawatt value and a price. For every increase in megawatt level, the settlement price also increases.

The CAISO calculates financial settlements based on the difference between schedules and actual meter data and bid prices during each hour. Locational Marginal Prices (LMP) are used in settlement calculations. The LMP is the price of a unit of energy at a particular location at a given time. LMPs are influenced by nearby generation, load level, and transmission constraints and losses.

# Appendix H – Separate City Results

## Introduction

A jurisdiction participation case was developed to present the impacts of designing a CCE with only one of the four jurisdictions. The base case includes all four cities; however, a single jurisdiction can individually establish and operate a CCE. The benefit of a single city CCE is that the city can make all policy decisions on revenues, power mix, and programs. However, all risk and liability associated with the CCE fall solely on this single jurisdiction. In this structure, it is recommended that the Partners develop contractual language to minimize risk to general funds, maintain adequate operating reserves, proactively track regulatory activities, and manage its energy portfolio. Solana Energy Alliance, Apple Valley Choice Energy, Lancaster Choice Energy, and CleanPowerSF are examples of single jurisdiction governance models.

The feasibility analysis found that the larger cities of Carlsbad and Oceanside can establish a single jurisdiction CCEs and still provide 2% rate discounts to ratepayers. Encinitas can also establish a CCE, but the projected rate savings are only 1% and several costs were reduced to ensure reserve requirements are met by the end of the analysis period. To operate a financially stable CCE in Encinitas, costs would have to be reduced further to ensure sufficient reserves are collected during the first 3-4 years. Finally, the analysis shows that a single jurisdiction CCE in Del Mar is not likely to be cost effective.

## Analysis

The financial proforma model was developed for each city based on the 50% Renewable power offering. Power supply, data management, billing, SDG&E charges, and non-bypassable charges were reduced to reflect the lower load and number of customers. For the remaining costs, the assumptions were modified to meet the expected requirement for each city based on the potential number of customers.

### Carlsbad

The City of Carlsbad has about 50,000 accounts or about 34% of the four-city total. If the City of Carlsbad decides to establish a standalone CCE, it was assumed that the staffing, consulting, and administrative costs would be approximately the same as a four-city CCE. The only change in costs assumed were related to power supply, data management and SDG&E charges. In addition, the working capital needs were reduced to $7 million. Based on this analysis, Carlsbad can offer 2% discount to SDG&E bills and collect up to $18 million in reserves by 2030.

**Del Mar**

The City of Del Mar has approximately 2,900 accounts or about 2% of the four-city total. If the City of Del Mar decides to establish a standalone CCE, the costs other than those related to power supply, data management and SDG&E charges would need to be below $200,000 per year. To model the scenario for Del Mar, it was assumed that the CCE would only spend $100,000 per year in staffing costs, $150,000 in consulting costs, and $10,000 in A&G. For the analysis, the working capital needs were reduced to $800,000 and it was assumed that it would be paid off over 10 years. Based on this conservative analysis, if Del Mar offers 1% discount to SDG&E rates, Del Mar would not be able to collect sufficient reserves. It can therefore be concluded that Del Mar is too small to operate a CCE.

**Encinitas**

The City of Encinitas has approximately 26,000 accounts or about 20% of the four-city total. If the City of Encinitas decides to establish a standalone CCE, the costs other than those related to power supply, data management and SDG&E charges would need to be below $2 million per year. To model the scenario for Encinitas, it was assumed that the CCE would spend approximately $1,100,000 per year in staffing costs, another $330,000 in consulting costs, and $10,000 in A&G. For the analysis, the working capital needs were reduced to $4.1 million and it was assumed that it would be paid off over three years. Based on this analysis, if Encinitas offers 1% discount to SDG&E bills then the reserve level by 2030 would only be $1.7 million. It can therefore be concluded that while Encinitas could operate a standalone CCE, the costs other than those related to power supply, data management and SDG&E charges would need to be significantly below $2 million per year in order for sufficient reserves to be accumulated during the first three years.

**Oceanside**

The City of Oceanside has about 70,000 accounts or about 46% of the four-city total. If the City of Oceanside decides to establish a standalone CCE, it was assumed that the staffing, consulting, and administrative costs would be approximately the same as a four-city CCE. The only change in costs assumed were related to power supply, data management and SDG&E charges. In addition, the working capital needs were reduced to $8.7 million. Based on this analysis, Oceanside can offer 2% discount to SDG&E rates and collect up to $16.7 million in reserves by 2030.

## Results

The base case analysis demonstrates that a four-city CCE could offer 2% rate savings for a 50% renewable product. Under the separate city results, the proformas on the following pages demonstrate that the same level of savings could potentially be offered by Oceanside and Carlsbad, while Encinitas would only be able to reduce rates by 1% although additional cost reductions would be needed to ensure robust financial performance of the CCE. Finally, the results show that Del Mar is likely too small to operate as a separate CCE.

Exhibit H-1

City of Carlsbad

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Revenues from Operations ($)** | | | | | | | | | | | |
| Electric Sales Revenues | $0 | $43,627,456 | $51,982,455 | $52,603,359 | $53,059,934 | $55,252,451 | $55,919,725 | $56,771,213 | $57,983,415 | $58,857,041 | $59,741,485 |
| Less Uncollected Accounts | $0 | $70,965 | $93,271 | $93,162 | $96,802 | $101,085 | $104,447 | $108,056 | $111,745 | $115,582 | $119,328 |
| **Total Revenues** | $0 | $43,556,490 | $51,889,184 | $52,510,197 | $52,963,133 | $55,151,366 | $55,815,277 | $56,663,158 | $57,871,669 | $58,741,459 | $59,622,157 |
| | | | | | | | | | | | |
| **Cost of Operations ($)** | | | | | | | | | | | |
| Cost of Energy | $0 | $30,031,812 | $41,108,302 | $42,582,397 | $44,304,231 | $46,350,400 | $47,987,303 | $49,709,031 | $51,449,317 | $53,266,137 | $55,087,997 |
| | | | | | | | | | | | |
| *Operating & Administrative* | | | | | | | | | | | |
| Billing & Data Management | $0 | $574,746 | $785,207 | $802,913 | $821,019 | $839,533 | $858,464 | $877,822 | $897,617 | $917,859 | $938,556 |
| SDG&E Fees | $0 | $129,901 | $130,226 | $130,551 | $130,877 | $131,205 | $131,533 | $131,861 | $132,191 | $132,522 | $132,853 |
| SDG&E Setup and StartUp Fees | $0 | $80,189 | $83,789 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Consulting Services | $426,700 | $1,617,822 | $1,411,407 | $1,439,635 | $1,468,427 | $1,497,796 | $1,527,752 | $1,558,307 | $1,589,473 | $1,621,263 | $1,653,688 |
| Staffing | $389,299 | $2,204,114 | $2,248,196 | $2,293,160 | $2,339,023 | $2,385,804 | $2,433,520 | $2,482,190 | $2,531,834 | $2,582,471 | $2,634,120 |
| General & Administrative expenses | $28,560 | $181,030 | $132,651 | $135,304 | $158,410 | $177,184 | $143,586 | $146,457 | $169,787 | $188,788 | $155,422 |
| Debt Service | $114,607 | $1,317,980 | $1,604,498 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total O&A Costs | $959,166 | $6,105,781 | $6,395,972 | $4,801,563 | $4,917,757 | $5,031,521 | $5,094,854 | $5,196,638 | $5,320,902 | $5,442,902 | $5,514,639 |
| **Total Cost & Reserves** | $959,166 | $36,137,593 | $47,504,274 | $47,383,960 | $49,221,987 | $51,381,921 | $53,082,157 | $54,905,670 | $56,770,219 | $58,709,039 | $60,602,636 |
| | | | | | | | | | | | |
| **CCE Program Surplus/(Deficit)** | ($959,166) | $7,418,897 | $4,384,910 | $5,126,237 | $3,741,145 | $3,769,445 | $2,733,120 | $1,757,488 | $1,101,451 | $32,421 | ($980,478) |
| **CCE Cumulative Reserves From Operations** | ($959,166) | $6,459,731 | $10,844,641 | $15,970,878 | $19,712,023 | $23,481,468 | $26,214,588 | $27,972,076 | $29,073,526 | $29,105,947 | $28,125,469 |
| | | | | | | | | | | | |
| **Reserve Additions** | | | | | | | | | | | |
| Operating Reserve Contributions | ($959,166) | $7,418,897 | $4,384,910 | $5,126,237 | $3,741,145 | $3,769,445 | $2,733,120 | $1,757,488 | $1,101,451 | $32,421 | ($980,478) |
| Cash from Financing | $2,000,000 | $5,000,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| **Total Additions** | $1,040,834 | $12,418,897 | $4,384,910 | $5,126,237 | $3,741,145 | $3,769,445 | $2,733,120 | $1,757,488 | $1,101,451 | $32,421 | ($980,478) |
| **Reserve Targets** | $315,342 | $11,880,853 | $15,617,844 | $15,578,288 | $16,182,571 | $16,892,686 | $17,451,668 | $18,051,179 | $18,664,182 | $19,301,602 | $19,924,154 |
| | | | | | | | | | | | |
| **Reserve Outlays** | | | | | | | | | | | |
| Start-up Funding Payments + Bonds + Collateral | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Working Capital Repayment (Remainder) | $0 | $0 | $0 | $4,469,404 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| New Programs/Additional Rate Savings | $0 | $0 | $0 | $2,923,187 | $0 | $6,196,191 | $0 | $3,332,115 | $0 | $0 | $0 |
| **Total Reserve Outlays** | $0 | $0 | $0 | $7,392,590 | $0 | $6,196,191 | $0 | $3,332,115 | $0 | $0 | $0 |
| | | | | | | | | | | | |
| **Rate Stabilization Reserve Balance** | **$1,040,834** | **$13,459,731** | **$17,844,641** | **$15,578,288** | **$19,319,433** | **$16,892,686** | **$19,625,806** | **$18,051,179** | **$19,152,630** | **$19,185,050** | **$18,204,572** |
| | | | | | | | | | | | |
| CCE Total Bill | $0 | $136,619,121 | $175,755,600 | $179,011,980 | $182,332,936 | $187,273,745 | $190,747,384 | $194,289,967 | $197,902,933 | $201,587,748 | $205,345,912 |
| SDG&E Total Bill | $0 | $139,407,266 | $179,342,449 | $182,665,285 | $186,054,016 | $191,095,658 | $194,640,188 | $198,255,069 | $201,941,768 | $205,701,783 | $209,536,645 |
| | | | | | | | | | | | |
| Difference | $0 | $2,788,145 | $3,586,849 | $3,653,306 | $3,721,080 | $3,821,913 | $3,892,804 | $3,965,101 | $4,038,835 | $4,114,036 | $4,190,733 |
| Savings | 0% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |

Exhibit H-2

City of Del Mar

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Revenues from Operations ($)** | | | | | | | | | | | |
| Electric Sales Revenues | $0 | $1,808,337 | $2,122,109 | $2,147,767 | $2,165,818 | $2,273,118 | $2,300,950 | $2,337,254 | $2,390,172 | $2,427,446 | $2,465,193 |
| Less Uncollected Accounts | $0 | $3,758 | $4,734 | $4,509 | $4,682 | $4,862 | $5,019 | $5,183 | $5,359 | $5,521 | $5,695 |
| **Total Revenues** | $0 | $1,804,579 | $2,117,376 | $2,143,259 | $2,161,136 | $2,268,256 | $2,295,931 | $2,332,071 | $2,384,814 | $2,421,925 | $2,459,498 |
| | | | | | | | | | | | |
| **Cost of Operations ($)** | | | | | | | | | | | |
| Cost of Energy | $0 | $1,245,497 | $1,724,643 | $1,786,487 | $1,858,724 | $1,944,568 | $2,013,243 | $2,085,475 | $2,158,487 | $2,234,709 | $2,311,143 |
| | | | | | | | | | | | |
| *Operating & Administrative* | | | | | | | | | | | |
| Billing & Data Management | $0 | $34,281 | $46,706 | $47,759 | $48,836 | $49,938 | $51,064 | $52,215 | $53,393 | $54,597 | $55,828 |
| SDG&E Fees | $0 | $7,727 | $7,746 | $7,766 | $7,785 | $7,804 | $7,824 | $7,843 | $7,863 | $7,883 | $7,902 |
| SDG&E Setup and StartUp Fees | $0 | $32,985 | $36,585 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Consulting Services | $76,500 | $156,060 | $159,181 | $162,365 | $165,612 | $168,924 | $172,303 | $175,749 | $179,264 | $182,849 | $186,506 |
| Staffing | $76,500 | $156,060 | $159,181 | $162,365 | $165,612 | $168,924 | $172,303 | $175,749 | $179,264 | $182,849 | $186,506 |
| General & Administrative expenses | $7,140 | $130,050 | $132,651 | $135,304 | $143,110 | $140,770 | $143,586 | $146,457 | $154,487 | $152,374 | $155,422 |
| Debt Service | $91,686 | $183,371 | $183,371 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total O&A Costs | $251,826 | $700,534 | $725,422 | $515,559 | $530,956 | $536,361 | $547,079 | $558,014 | $574,270 | $580,552 | $592,164 |
| **Total Cost & Reserves** | $251,826 | $1,946,031 | $2,450,066 | $2,302,045 | $2,389,680 | $2,480,929 | $2,560,322 | $2,643,489 | $2,732,757 | $2,815,261 | $2,903,307 |
| | | | | | | | | | | | |
| **CCE Program Surplus/(Deficit)** | ($251,826) | ($141,452) | ($332,690) | ($158,787) | ($228,544) | ($212,673) | ($264,390) | ($311,418) | ($347,943) | ($393,336) | ($443,808) |
| **CCE Cumulative Reserves From Operations** | ($251,826) | ($393,278) | ($725,967) | ($884,754) | ($1,113,298) | ($1,325,971) | ($1,590,361) | ($1,901,779) | ($2,249,722) | ($2,643,058) | ($3,086,866) |
| | | | | | | | | | | | |
| **Reserve Additions** | | | | | | | | | | | |
| Operating Reserve Contributions | ($251,826) | ($141,452) | ($332,690) | ($158,787) | ($228,544) | ($212,673) | ($264,390) | ($311,418) | ($347,943) | ($393,336) | ($443,808) |
| Cash from Financing | $800,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| **Total Additions** | $548,174 | ($141,452) | ($332,690) | ($158,787) | ($228,544) | ($212,673) | ($264,390) | ($311,418) | ($347,943) | ($393,336) | ($443,808) |
| **Reserve Targets** | $82,792 | $639,791 | $805,501 | $756,837 | $785,648 | $815,648 | $841,750 | $869,092 | $898,441 | $925,565 | $954,512 |
| | | | | | | | | | | | |
| **Reserve Outlays** | | | | | | | | | | | |
| Start-up Funding Payments + Bonds + Collateral | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Working Capital Repayment (Remainder) | $0 | $0 | $0 | $415,887 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| New Programs/Additional Rate Savings | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| **Total Reserve Outlays** | $0 | $0 | $0 | $415,887 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | | | | | | | |
| **Rate Stabilization Reserve Balance** | **$548,174** | **$406,722** | **$74,033** | **($500,641)** | **($729,185)** | **($941,858)** | **($1,206,248)** | **($1,517,666)** | **($1,865,609)** | **($2,258,945)** | **($2,702,754)** |
| | | | | | | | | | | | |
| CCE Total Bill | $0 | $6,226,877 | $8,091,861 | $8,244,958 | $8,401,140 | $8,641,352 | $8,804,912 | $8,971,768 | $9,141,990 | $9,315,648 | $9,492,815 |
| SDG&E Total Bill | $0 | $6,289,775 | $8,173,597 | $8,328,241 | $8,486,000 | $8,728,638 | $8,893,850 | $9,062,392 | $9,234,333 | $9,409,746 | $9,588,702 |
| | | | | | | | | | | | |
| Difference | $0 | $62,898 | $81,736 | $83,282 | $84,860 | $87,286 | $88,939 | $90,624 | $92,343 | $94,097 | $95,887 |
| Savings | 0% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% |

Exhibit H-3

City of Encinitas

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Revenues from Operations ($)** | | | | | | | | | | | |
| Electric Sales Revenues | $0 | $15,560,386 | $18,265,099 | $18,485,981 | $18,641,093 | $19,575,940 | $19,815,685 | $20,128,660 | $20,585,245 | $20,906,585 | $21,232,090 |
| Less Uncollected Accounts | $0 | $26,719 | $35,085 | $34,335 | $35,655 | $37,190 | $38,441 | $39,755 | $41,095 | $42,470 | $43,861 |
| **Total Revenues** | $0 | $15,533,667 | $18,230,015 | $18,451,646 | $18,605,437 | $19,538,750 | $19,777,244 | $20,088,904 | $20,544,150 | $20,864,116 | $21,188,229 |
| | | | | | | | | | | | |
| **Cost of Operations ($)** | | | | | | | | | | | |
| Cost of Energy | $0 | $10,653,682 | $14,775,949 | $15,305,797 | $15,924,692 | $16,660,166 | $17,248,534 | $17,867,391 | $18,492,919 | $19,145,956 | $19,800,804 |
| | | | | | | | | | | | |
| *Operating & Administrative* | | | | | | | | | | | |
| Billing & Data Management | $0 | $311,181 | $424,074 | $433,637 | $443,416 | $453,415 | $463,639 | $474,094 | $484,785 | $495,717 | $506,896 |
| SDG&E Fees | $0 | $70,157 | $70,332 | $70,508 | $70,684 | $70,861 | $71,038 | $71,216 | $71,394 | $71,572 | $71,751 |
| SDG&E Setup and StartUp Fees | $0 | $57,106 | $60,706 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Consulting Services | $168,300 | $421,362 | $456,319 | $465,446 | $474,755 | $484,250 | $493,935 | $503,814 | $513,890 | $524,168 | $534,651 |
| Staffing | $561,000 | $1,144,440 | $1,167,329 | $1,190,675 | $1,214,489 | $1,238,779 | $1,263,554 | $1,288,825 | $1,314,602 | $1,340,894 | $1,367,712 |
| General & Administrative expenses | $7,140 | $130,050 | $132,651 | $135,304 | $143,110 | $140,770 | $143,586 | $146,457 | $154,487 | $152,374 | $155,422 |
| Debt Service | $114,607 | $939,777 | $939,777 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total O&A Costs | $851,047 | $3,074,073 | $3,251,189 | $2,295,571 | $2,346,454 | $2,388,075 | $2,435,752 | $2,484,406 | $2,539,157 | $2,584,725 | $2,636,431 |
| **Total Cost & Reserves** | $851,047 | $13,727,755 | $18,027,138 | $17,601,368 | $18,271,146 | $19,048,241 | $19,684,286 | $20,351,798 | $21,032,076 | $21,730,681 | $22,437,235 |
| | | | | | | | | | | | |
| **CCE Program Surplus/(Deficit)** | ($851,047) | $1,805,912 | $202,877 | $850,278 | $334,291 | $490,509 | $92,957 | ($262,893) | ($487,926) | ($866,565) | ($1,249,006) |
| **CCE Cumulative Reserves From Operations** | ($851,047) | $954,865 | $1,157,742 | $2,008,020 | $2,342,311 | $2,832,820 | $2,925,777 | $2,662,884 | $2,174,958 | $1,308,393 | $59,387 |
| | | | | | | | | | | | |
| **Reserve Additions** | | | | | | | | | | | |
| Operating Reserve Contributions | ($851,047) | $1,805,912 | $202,877 | $850,278 | $334,291 | $490,509 | $92,957 | ($262,893) | ($487,926) | ($866,565) | ($1,249,006) |
| Cash from Financing | $4,100,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| **Total Additions** | $3,248,953 | $1,805,912 | $202,877 | $850,278 | $334,291 | $490,509 | $92,957 | ($262,893) | ($487,926) | ($866,565) | ($1,249,006) |
| **Reserve Targets** | $279,796 | $4,513,235 | $5,926,730 | $5,786,751 | $6,006,952 | $6,262,435 | $6,471,546 | $6,691,002 | $6,914,655 | $7,144,333 | $7,376,625 |
| | | | | | | | | | | | |
| **Reserve Outlays** | | | | | | | | | | | |
| Start-up Funding Payments + Bonds + Collateral | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Working Capital Repayment (Remainder) | $0 | $0 | $0 | $2,436,089 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| New Programs/Additional Rate Savings | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| **Total Reserve Outlays** | $0 | $0 | $0 | $2,436,089 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| | | | | | | | | | | | |
| **Rate Stabilization Reserve Balance** | **$3,248,953** | **$5,054,865** | **$5,257,742** | **$3,671,931** | **$4,006,222** | **$4,496,731** | **$4,589,688** | **$4,326,795** | **$3,838,869** | **$2,972,304** | **$1,723,298** |
| | | | | | | | | | | | |
| CCE Total Bill | $0 | $53,128,364 | $69,101,269 | $70,406,455 | $71,737,902 | $73,803,562 | $75,198,065 | $76,620,634 | $78,071,862 | $79,552,350 | $81,062,798 |
| SDG&E Total Bill | $0 | $53,665,014 | $69,799,262 | $71,117,631 | $72,462,528 | $74,549,053 | $75,957,641 | $77,394,580 | $78,860,466 | $80,355,909 | $81,881,532 |
| | | | | | | | | | | | |
| Difference | $0 | $536,650 | $697,993 | $711,176 | $724,625 | $745,491 | $759,576 | $773,946 | $788,605 | $803,559 | $818,733 |
| Savings | 0% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% | 1% |

Exhibit H-4

City of Oceanside

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Revenues from Operations ($)** | | | | | | | | | | | |
| Electric Sales Revenues | $0 | $42,496,299 | $50,108,857 | $50,706,301 | $51,138,293 | $53,424,355 | $54,068,784 | $54,898,185 | $56,090,096 | $56,941,092 | $57,802,625 |
| Less Uncollected Accounts | $0 | $70,035 | $91,023 | $90,024 | $93,533 | $97,661 | $100,899 | $104,377 | $107,934 | $111,634 | $115,242 |
| **Total Revenues** | $0 | $42,426,264 | $50,017,834 | $50,616,277 | $51,044,760 | $53,326,695 | $53,967,885 | $54,793,808 | $55,982,161 | $56,829,458 | $57,687,383 |
| | | | | | | | | | | | |
| **Cost of Operations ($)** | | | | | | | | | | | |
| Cost of Energy | $0 | $28,842,815 | $39,547,303 | $40,965,422 | $42,621,873 | $44,590,344 | $46,165,089 | $47,821,438 | $49,495,640 | $51,243,470 | $52,996,149 |
| | | $59.88 | $62.70 | $64.79 | $67.24 | $70.17 | $72.47 | $74.88 | $77.31 | $79.84 | 82.36493438 |
| | | | | | | | | | | | |
| *Operating & Administrative* | | | | | | | | | | | |
| Billing & Data Management | $0 | $787,958 | $1,072,220 | $1,096,399 | $1,121,122 | $1,146,404 | $1,172,255 | $1,198,689 | $1,225,720 | $1,253,360 | $1,281,623 |
| SDG&E Fees | $0 | $177,383 | $177,826 | $178,271 | $178,717 | $179,163 | $179,611 | $180,060 | $180,510 | $180,962 | $181,414 |
| SDG&E Setup and StartUp Fees | $0 | $98,534 | $102,134 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Consulting Services | $426,700 | $1,617,822 | $1,411,407 | $1,439,635 | $1,468,427 | $1,497,796 | $1,527,752 | $1,558,307 | $1,589,473 | $1,621,263 | $1,653,688 |
| Staffing | $389,299 | $2,204,114 | $2,248,196 | $2,293,160 | $2,339,023 | $2,385,804 | $2,433,520 | $2,482,190 | $2,531,834 | $2,582,471 | $2,634,120 |
| General & Administrative expenses | $28,560 | $181,030 | $132,651 | $135,304 | $158,410 | $177,184 | $143,586 | $146,457 | $169,787 | $188,788 | $155,422 |
| Debt Service | $114,607 | $1,994,161 | $1,994,161 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Total O&A Costs | $959,166 | $7,061,002 | $7,138,596 | $5,142,768 | $5,265,700 | $5,386,351 | $5,456,724 | $5,565,704 | $5,697,324 | $5,826,843 | $5,906,267 |
| **Total Cost & Reserves** | $959,166 | $35,903,818 | $46,685,898 | $46,108,190 | $47,887,573 | $49,976,695 | $51,621,813 | $53,387,143 | $55,192,964 | $57,070,313 | $58,902,416 |
| | | | | | | | | | | | |
| **CCE Program Surplus/(Deficit)** | ($959,166) | $6,522,446 | $3,331,936 | $4,508,087 | $3,157,187 | $3,350,000 | $2,346,072 | $1,406,665 | $789,197 | ($240,856) | ($1,215,033) |
| **CCE Cumulative Reserves From Operations** | ($959,166) | $5,563,280 | $8,895,216 | $13,403,303 | $16,560,490 | $19,910,490 | $22,256,562 | $23,663,227 | $24,452,424 | $24,211,569 | $22,996,536 |
| | | | | | | | | | | | |
| **Reserve Additions** | | | | | | | | | | | |
| Operating Reserve Contributions | ($959,166) | $6,522,446 | $3,331,936 | $4,508,087 | $3,157,187 | $3,350,000 | $2,346,072 | $1,406,665 | $789,197 | ($240,856) | ($1,215,033) |
| Cash from Financing | $8,700,000 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| **Total Additions** | $7,740,834 | $6,522,446 | $3,331,936 | $4,508,087 | $3,157,187 | $3,350,000 | $2,346,072 | $1,406,665 | $789,197 | ($240,856) | ($1,215,033) |
| **Reserve Targets** | $315,342 | $11,803,995 | $15,348,789 | $15,158,857 | $15,743,860 | $16,430,694 | $16,971,555 | $17,551,937 | $18,145,632 | $18,762,843 | $19,365,178 |
| | | | | | | | | | | | |
| **Reserve Outlays** | | | | | | | | | | | |
| Start-up Funding Payments + Bonds + Collateral | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Working Capital Repayment (Remainder) | $0 | $0 | $0 | $5,279,527 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| New Programs/Additional Rate Savings | $0 | $0 | $0 | $1,664,918 | $0 | $5,235,350 | $0 | $2,631,494 | $0 | $0 | $0 |
| **Total Reserve Outlays** | $0 | $0 | $0 | $6,944,446 | $0 | $5,235,350 | $0 | $2,631,494 | $0 | $0 | $0 |
| | | | | | | | | | | | |
| **Rate Stabilization Reserve Balance** | **$7,740,834** | **$14,263,280** | **$17,595,216** | **$15,158,857** | **$18,316,045** | **$16,430,694** | **$18,776,766** | **$17,551,937** | **$18,341,135** | **$18,100,279** | **$16,885,246** |
| | | | | | | | | | | | |
| CCE Total Bill | $0 | $135,242,074 | $173,691,247 | $176,918,945 | $180,210,981 | $185,239,832 | $188,684,975 | $192,198,638 | $195,782,250 | $199,437,273 | $203,165,200 |
| SDG&E Total Bill | $0 | $138,002,116 | $177,235,967 | $180,529,536 | $183,888,568 | $189,020,237 | $192,535,689 | $196,121,059 | $199,777,806 | $203,507,422 | $207,311,429 |
| | | | | | | | | | | | |
| Difference | $0 | $2,760,042 | $3,544,719 | $3,610,591 | $3,677,587 | $3,780,405 | $3,850,714 | $3,922,421 | $3,995,556 | $4,070,148 | $4,146,229 |
| Savings | 0% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% | 2% |