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# Appendix B: Additional Study Detail

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1. CCA Supply and Demand Management Strategies

This discussion provides additional detail on supply side and demand side management strategies applicable to the Central Coast CCA. A foundational component of these strategies is the integrated resource plan (IRP). The purpose of an IRP is generally to examine a host of supply-side and demand-side resources to develop a resource plan that reliably meets future load at the least possible cost. Load Serving Entities (LSEs) develop IRPs that cover multiyear periods and incorporate not only load, generation, and price forecasts, but also integrate supply-side options, including energy efficiency programs and other demand side management (DSM) initiatives. The resulting IRP should:

1. identify and justify all of the assumptions used for all aspects of the IRP;
2. identify and prioritize any planning constraints or specific goals that are to be achieved, such as Renewable Portfolio Standards, diversity of resources, energy efficiency objectives, procurement strategies, and other constraints;
3. quantify and describe the specific resources needed over the planning horizon and their size, type, timing, and location as applicable; and
4. provide guidance and direction to the supply managers for procurement activities over the plan time horizon.

1.1. Supply Side Management

Managing a CCA to supply cost-effective, economically reliable electric power to customers involves a variety of functions and business processes, largely involving demand forecasting and power purchase and other agreements to balance the constantly changing supply and demand without excess costs or outages.

For example, the electricity demand forecast must be met with both electric power capacity known as resource adequacy (RA), and typically measured in megawatts (MW), and electric energy, measured in megawatt-hours (MWh). RA and electric energy can be self-generated and/or procured through bilateral power purchase agreements (PPA). However, load forecasts are never exactly accurate, and actual load may vary significantly from forecasts at any given point in time. Therefore, the California Independent System Operator (CAISO) runs a day-ahead and real-time electric energy market for participating LSEs to ensure a virtually instantaneous balance between electricity supply and demand. If the expected demand from customer load exceeds the expected amount of generation supply, then additional power must be procured through the CAISO markets to satisfy the demand. If more electricity is procured by PPAs than is actually needed, the excess can be sold through the CAISO wholesale electric energy market.

The CCA is responsible for forecasting its customer electricity demand and energy use on an hour-ahead, day-ahead, month-ahead, and annual basis and for developing a supply portfolio that economically best

Demand Side Management (DSM) is defined herein as modification of consumer demand for electric energy (kWh) and power (kW) through various methods such as financial incentives, direct control by the utility, and behavioral changes through education.
meets those needs on a price/risk adjusted basis. Customer demand can vary based on many factors, such as weather, day of the week, time of day, etc. However, experts in the electric industry have developed proven approaches for developing demand and use forecasts that inform the power procurement strategy and procurement approach. Done correctly, the bulk of the forecasted capacity and energy needs can be optimally procured through structured products in various markets with different time (term) horizons. The management of the remaining daily and hourly shortfall and/or excess supply is the responsibility of the CCA through their portfolio management/scheduling coordination function.

The majority of distributed energy resources (DER) in the region are solar photovoltaic (PV). Solar PV is known as a variable generation resource because the output depends on time of day, time of year, and other factors such as cloud cover. Customer-owned solar PV effectively lowers a customer's electricity demand and is not considered a generation supply source for LSEs. Therefore, customer-owned DER do not count toward the state-mandated RPS for LSEs. The variable output from customer-owned solar PV must be taken into account when a CCA performs its load analysis and negotiates PPAs, as DER act as a reduction to load and also change the load profile. The impact on load of DSM initiatives also must be taken into account.

Operationally, Central Coast Power CCA will need to determine which aspects of the CCA will be operated and managed by in-house staff and which aspects would be best outsourced. For example, multiple third party electricity service providers can provide energy procurement services as well as the required Schedule Coordinator interface to the CAISO. In addition, the incumbent IOUs will provide services to the CCA, including billing, and may offer the CCA additional, fee-based support services.

1.2. Demand Side Management

With emerging customer-owned DER and DSM, customers are more actively engaged with their electricity supply and usage than ever before. A CCA allows for more localized control and potentially more options for customers to become active managers of their electricity usage and environmental impact. This section explores some of the programs that a CCA can offer to customers in terms of DSM programs, which typically include a host of program types, including conservation, energy efficiency, demand management, and demand response, as outlined in Figure B-1.

![Figure B-1 Model of Demand Side Management](image-url)
1.2.a Energy Efficiency

Both SCE and PG&E currently have programs for both energy efficiency and demand response. Central Coast Power CCA would receive some RA credit for customers participating in the incumbent utilities' programs. CCA customers will continue to be eligible for the incumbent utilities' energy efficiency programs after CCA enrollment. Additionally, CCAs can use energy efficiency funds collected from the IOUs servicing their territory after approval by the California Public Utilities Commission (CPUC) to allocate a portion of the funding that the IOU(s) collects for CCA energy efficiency programs. However, the CPUC requires that energy efficiency programs be cost-effective and lead to direct energy savings. In addition, the CPUC will provide funding for unique programs proposed by Central Coast Power CCA that do not duplicate programs currently offered by the incumbent utility.

Use of energy efficiency funds is authorized under Public Utilities Code Section 381.1(a)–(d). The only distinction for CCAs, as opposed to other entities, is in Section 381.1(d), which states:

“The commission shall establish an impartial process for making the determination of whether a third party, including a community choice aggregator, may become administrators for cost-effective energy efficiency and conservation programs pursuant to subdivision (a), and shall not delegate or otherwise transfer the commission’s authority to make this determination for a community choice aggregator to an electrical corporation.”

The CPUC concluded that:

“…it appears the Commission itself must handle the selection of the CCA programs. In this way, the administrative structure for CCA programs is exactly the same as for the RENs (Regional Energy Networks) described above. Therefore, even though MEA’s proposal for 2013-2014 is not defined as a REN, we treat it, for administrative purposes for this portfolio period, as if it were a REN. If MEA had elected to administer funds only from its own customers under Section 381.1(e) and (f), our conclusion would likely have mirrored our resolution on MEA’s 2012 energy efficiency plan.”

In addition to earmarked energy efficiency funds collected from customers, energy efficiency programs that are not dependent upon CPUC funding could be CCA-funded through positive net margins (revenues less operating and non-operating expenses), which are not projected for most years of the study period under all scenarios examined. As with all supply-side and demand-side options considered, the potential energy efficiency options would need to be evaluated from a cost-benefit perspective and analyzed for technical and financial feasibility over the life of the option. Spending on energy efficiency programs should be prioritized for those that provide the highest benefit to cost ratio.

Coordinating CCA energy efficiency outreach material with any existing energy programs, such as the emPower Central Coast program, would ensure that customers receive consistent and accurate information and understand the complete range of available programs. Additionally, coordination of CCA projects with existing incentive programs could leverage other funding mechanisms and could increase the total benefits for CCA customers.
An example of CCA energy efficiency programs can be seen with MCE whose energy savings programs have evolved over time. In 2012 MCE elected to access only the energy efficiency funds collected from its own customers. For 2013 and 2014, MCE requested authority to administer not only energy efficiency funds collected from its customers, but also from other customers within PG&E’s territory. CPUC Decision 12-11-015, dated November 8, 2012, authorized MCE to spend over $4 million dollars on four energy efficiency programs. Funding for all four of the energy efficiency programs proposed by MCE was approved by the CPUC. The four energy efficiency programs are briefly summarized as follows:

1) The **Multifamily Energy Efficiency Program** provides incentives for multifamily residential buildings of up to $50 per unit, with a goal of a 15% total energy savings. The program also proposes to provide financing for the remainder of costs via an on-bill repayment mechanism. The approved budget for the program is $861,781.

2) The **Single Family Utility Demand Reduction Program** targets high-energy-consuming single-family homes within its service area. The program offers targeted marketing and online software to present options for high-energy-consuming users for both energy efficiency and renewable energy projects. The program does not propose to offer incentives, but rather is aimed at awareness and information that would lead to behavior and retrofit enhancements. The approved budget for the program is $851,400.

3) The **Small Commercial Program** offers incentives for multi-measure retrofits initiated through targeted outreach. It provides technical support to small commercial property owners in high-energy-use segments, which include, but are not limited to, restaurants, retail, and professional services. The program proposes three main sub-programs: a convenience store and small grocery energy efficiency development, a restaurant energy efficiency project, and a professional services energy efficiency project. The approved budget for the program is $1,380,024.

4) The **Financing Pilot Programs** proposes both an on-bill repayment program and a Standard Offer program to enable financing for underserved markets. MCE states that the on-bill repayment program will a) streamline the loan application and enrollment processes, b) offer customers and contractors support for wider and deeper retrofits, and c) leverage other MCE programs and services. The on-bill repayment program plans to partner with private banks or financing entities to provide financing to building owners, with the repayment charge placed as a line item on the bill. MCE is somewhat unique in that it relies on PG&E for its billing but controls certain line items related to its services. The approved budget for the program is $1,192,000.

While future potential CCA opt-out material provided to customers prior to CCA enrollment should not be used as marketing for energy efficiency programs, it should ensure that potential CCA customers understand that by choosing the CCA, they will not be forgoing any energy efficiency, solar, or other programs sponsored by the incumbent utilities.

**1.2.b Demand Management**

An emerging challenge for LSEs, including CCAs, is to manage the variance in customer demand due to customer-owned DER. A demand management program to help customers better understand their demand profile and incentivize behavior can result in customers proactively managing their demand and potentially save them money and reduce system resource requirements. This is a new and innovative approach that was demonstrated under Wisconsin’s Focus on Energy program called On Demand Savings.
On Demand Savings enrolled commercial customers with building automation and control systems (BACS). The BACS were used to co-optimize energy consumption (kWh) as well as to reduce demand (kW). Modern BACS are capable of this co-optimization, but the typical programming of the system only focuses on minimizing energy consumption. By co-optimizing to minimize energy consumption and also setting peak demand reduction targets relative to the same month in prior years, customers reduced their peak demand by 20% in the first month and roughly 15% overall. Customers not only benefited from the program incentive to implement these changes but also reduced their annual and monthly demand charges on their bill.

**1.2.c Demand Response**

Demand response is the modification of customers’ energy consumption through either a price signal (defined in an electric rate tariff) or a dispatch instruction from the LSE (typically these are voluntary enrollment programs).

Basic demand response with price signals includes rate structures that have time varying rates and peak rates that are intended to incentivize customers to use less electricity during the more expensive times. Time of use (TOU) rates seek to better align the price the customer sees for electricity with the real-time cost to supply that energy. Typically, TOU rate structures include several periods per day, such as morning, day, evening, and night. Critical peak pricing (CPP) is a TOU structure with certain high electricity demand days and corresponding higher rates during periods when a CPP event is called. CPP typically builds upon TOU tariffs by creating higher rates on days when electricity demand is expected to be among the highest of the year. The rate design is typically structured to encourage conservation, energy efficiency, and shifting of usage to off-peak periods. Figure B-2 illustrates both the TOU and CPP pricing concepts.

*Figure B-2 Aligning Electricity Demand and Supply Cost with the Time-of-Use Tariff Structure*
Currently, all IOU large commercial customers have mandatory CPP rates and all other commercial customers have mandatory TOU rates. The IOUs have also been ordered to file applications proposing default TOU rates for residential customers. The CPUC anticipates that default TOU rates will be implemented “the later of 2019 or the date the tier ratio reaches 1:1.25.”

Additionally, customers can participate in demand response programs that are designed to treat electricity like a commodity: when prices are high, demand decreases, and when prices are low, demand increases. These programs often look at the CAISO prices or other load forecast data to trigger demand response program events. The demand response programs can also be used as a contingency resource for reliability when a generation resource, transmission infrastructure, or distribution infrastructure does not perform as expected. This application of demand response is often referred to as a “non-wires alternative” for traditional grid management procedures.

CPUC Decision 14-03-026, “Addressing Foundational Issue of the Bifurcation of Demand Response Programs,” split existing IOU demand response programs into “load-modifying” and “supply-side demand response programs.” Load-modifying demand response programs typically use rates and tariff pricing like time of use, critical peak pricing and peak time rebate, which have the effect of reducing or modifying electricity demand and usage. Supply-side demand response programs are dispatchable programs that can or should be integrated into the CAISO wholesale electricity market and would be bid and dispatched in competition with other CAISO market participating resources. A probable outcome after bifurcation is for load modifying demand response to have the effect of reducing the LSE RA requirement itself (through an adjustment to the baseline load forecast curve) while supply side demand response would help meet the RA requirement.

Additionally, under current rules, a CCA could use a portion of the demand response programs paid for by IOU ratepayers to meet CCA RA requirements. For example, MCE receives demand response capacity credits that are allocated by the CPUC and reduce MCE’s need to procure RA capacity. Currently, demand response programs provide 2% of MCE’s RA requirements.

In recent years, demand response has been used to reduce system peak demand. TOU and CPP rate structures are examples of this. However, targeting peak demand reduction results in long duration (greater than one hour) demand response, which can negatively impact customers’ demand response program satisfaction, participation, and performance.

A primary driver for high and low energy prices in CAISO is the variable output of renewable generation from both customer-owned DER and bulk scale systems. As a result, demand response programs can essentially be used to smooth out the changes in load due to variable customer-owned DER. One approach for this is to use the CAISO market price as an interpretation of that variance. Customer demand response resources can be aggregated to participate as a CAISO proxy demand resource that bids into the day-ahead and/or real-time markets. If the price triggers are met, resources either decrease load when prices are high or increase load when prices are low. However, the day-ahead and real-time energy markets have a minimum run time of one hour, which as discussed, negatively affects demand response and customer satisfaction. An emerging area for demand response is to participate in CAISO with proxy demand response as a real-time, non-spinning reserve ancillary service. The non-spinning reserve ancillary service is more closely aligned with the underlying renewable generation intermittency.
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challenge, where the demand response must be dispatched within five minutes and the average runtime is approximately twenty minutes. However, the demand response program sophistication needed to participate as a proxy demand resource non-spinning reserve ancillary service is significantly more complex.

Central Coast Power could develop its own demand response programs or solicit the services of a Demand Response Provider (aka Curtailment Service Provider or Demand Response Aggregator). Demand response programs could be offered into CAISO markets as a proxy demand resource and/or conducted outside of the CAISO market. However, if the Central Coast Power CCA demand response program is conducted outside of the CAISO market, the associated capacity will be considered load modifying rather than a supply resource and will not be eligible for RA credit. The Demand Analysis Working Group initiated by the California Energy Commission (CEC) and composed of stakeholders develops the protocols for determining load impacts and determining their effect on the RA requirements. Approximate demand response program startup costs can be estimated at $200 per kW of demand response capacity, and ongoing operational cost are approximately $20 per kW of demand response capacity.

1.2.d Plug-in Electric Vehicles

The electrification of vehicles represents a significant change event for the electric utility industry; and the implications and intensity of impacts are not fully understood. As illustrated in Figure B-3, projections display significant expected growth for the technology over the next few years. This growth could assist in replacing the load served by utilities lost due to distributed energy resources and could also cause peak demand to shift/and or increase and influence RA requirements.

*Figure B-3 Light-Duty Vehicle Sales: Alternative-Fuel Cars*
Appendix B

While Plug-in Electric Vehicles (PEV) represent a significant new load, little information is publicly available regarding PEV owners’ preferred charging times. Given that a typical PEV has a peak demand roughly equivalent to a single family residential home, particular attention is being paid to PEV charging behavior now. However, through special rate designs strategically incentivizing charging behavior, CCAs may have the capability to turn this potentially troublesome new load source into an asset to assist in the problems created by intermittent renewable energy generation.

Vehicle to Grid is a concept that has been discussed for many years and envisions vehicle charging as a balancing resource for the electric grid, similar to the way demand response can be a balancing resource. Significant work has been done to enable the technological foundation and standards for grid management using PEVs. For example, emerging smart inverters for battery energy storage systems could either provide energy to the grid or import the excess energy from DER. However, these Vehicle to Grid-based programs have not caught on for a variety of reasons, including the possibility of voiding the vehicle’s battery warranty by using it for an application other than driving and the possibility of reducing the overall battery life due to additional charging and discharging cycles. Therefore, current utility programs have focused on rate structures to encourage vehicle charging during off-peak times of the day. For example, both IOUs have PEV charging rates and Sonoma Clean Power also has an electric vehicle program.

1.3. Net Energy Metering and Feed-in Tariffs

Net Energy Metering (NEM) and Feed-in Tariffs (FITs) are rate design options for the CCA program to address customer-owned DER. The former is typically used for small scale PV distributed generation (DG) and the latter is for bi-lateral purchase agreements with larger scale resources. How these rate mechanisms are designed can either encourage or discourage DER proliferation. For example, NEM can encourage customer adoption of PV DG. Similarly, should a CCA program wish to encourage development of larger scale DER in a certain portion of its service territory, it could do so by creating an FIT that includes attractive financial arrangements targeted to this outcome.

NEM is a rate design that nets out customer energy usage against the generation output of its solar PV DG. Under NEM, the rate of credit applied to a customer’s bill can be set at various levels including the:

- Wholesale cost of energy
- Spot market cost of energy
- Avoided cost of energy
- CCA retail rate
- Value of solar

The level at which the NEM credit is set can encourage proliferation of DG. Some NEM tariffs include a fixed monthly charge to compensate the CCA for variability of CCA customer load. Although such mechanisms can protect CCA revenues, they can also serve to discourage DG adoption and to date no CCAs have implemented such charges.

FITs set forth the provisions governing renewable energy purchases of the CCA program from large third-party providers. The terms incorporated into a CCA program’s FIT can encourage development of such resources.
2. Distribution and DER-Related Risks and Mitigation

This section discusses and provides more detail on some technical distribution and DER-related risks faced by the Central Coast Power CCA. While these risks should be considered and addressed, they are not deemed to largely influence CCA feasibility at this juncture.

While maintaining the distribution infrastructure for reliability and safety will continue to be the responsibility of the IOU, one of the biggest challenges facing electricity distribution system operators are the challenges related to increasing DER, which is predominately solar PV. The electric distribution system was designed to deliver electricity from a bulk generation source to customers through transmission and distribution networks, generally with power flowing in one direction, from the generation source to end-use customers. As the capacity of customer-owned DER increases, the energy flows from the home or business into the distribution grid and from there in various directions that can change rapidly depending on demand and generation output. California utilities, including PG&E and SCE, are developing grid modernization plans intended to identify and implement the technology, systems, and operational processes to manage the steady growth in adoption of DER.

The economic analysis models and techniques employed in this feasibility study rely heavily on existing practices as well as incorporating reasonably conservative factors for the changing energy environment (e.g., growth in solar PV and PEV). However, growth in distribution-level generation (including additional technologies such as microgrid installations), growth in distribution-level energy storage systems, and the potential for development of distribution-level energy markets, products, and services may have material impacts on the economics of CCAs in future years.

There are several key efforts being addressed by the California utilities as participants in various forums, the outcomes of which will shape the future of the distribution network, in terms of technology, operations, and economics.

2.1. Grid Interconnection and Hosting Capacity

The Electric Power Research Institute is developing methodologies to assess “hosting capacity”—or the ability for the connections between the output terminals of a distribution substation and the input terminals of primary circuits to accommodate DER. Many physical and design factors affect the potential impact of DER on the performance of a given distribution system. Some systems can accommodate higher levels of DER before operating criteria are violated, and other systems are more vulnerable to exceeding acceptable limits.23

In terms of risk for the CCA, Central Coast Power would need to coordinate the enablement of customer-owned DER with the IOUs to ensure that the distributed generation locations can accommodate additional DER capacity.24,25 To the extent Central Coast Power chooses to offer a feed-in tariff, which is a rate tariff designed to compensate customers for excess energy produced from qualified DER systems located behind the customer meter (e.g. solar PV), the amount and timing of customer participation could be constrained by distribution hosting capacity.26 While the distribution system will continue to be the responsibility of the IOUs, constraints could limit the ability of Central Coast Power to grow a popular program which may negatively impact customer experience and satisfaction. Typically if there are transmission- and distribution-related system constraints (capacity, stability, or otherwise) the
CPUC will require upgrades and enhancements to alleviate those constraints.27

2.2. Smart Inverters

One of the mitigation options being pursued for integrating larger amounts of renewable DER and storage resources is the adoption of smart inverters. Smart inverters could potentially smooth out the changes in load due to the intermittency of DER in addition to providing frequency and power quality services, such as voltage support, at the localized level.

In conjunction with CPUC Electric Rule 2128 containing the interconnection, operating, and metering requirements for generation facilities to be connected to a utility’s distribution system, the CEC hosted the Smart Inverter Working Group,29 who developed specific recommendations for incorporation into Rule 21.

The implication for Central Coast Power CCA may be that when smart inverters are deployed on DER systems, more control, visibility, and, potentially distribution grid services may be possible. In some cases, these inverters may help support efforts of CCA customers who want to participate in CAISO markets using aggregated resources. Although not in use today, as the technology is developed, tested, proven, and deployed, the rules and processes governing the use and application will also evolve. The Central Coast Power CCA will need to follow these developments and may need to actively participate in the process to represent its interests and better achieve the goals of the CCA.

3. Other Risk Factors and Mitigation

First and foremost, ensuring experienced, professional management is the key to mitigating the inherent risks involved in providing any retail electric services. However, there are certain risks beyond the control of management that could negatively impact the economic and financial feasibility and rate competitiveness of the CCA. This section discusses and offers additional details on other regulatory and customer-related risks faced by the Central Coast Power CCA and offers some simple mitigation strategies.

3.1. Changes in the CCA Regulatory and Legislative Landscape

Many of these risks were discussed during the February 2017 CPUC en banc hearing on CCA issues.30 As a result of those discussions, the CCA regulatory requirements or framework may change, and the possibility of these changes adds risk to both existing CCAs and those exploring CCA. The assumptions embedded in this feasibility study are based on current CPUC and Public Utilities Code Section 381.1(a)–(d) rules and requirements for CCAs and IOUs.

Prior to the February 1, 2017 en banc hearing, the CPUC issued a background paper outlining the role of CCAs31 and discussing a number of issues associated with the continued proliferation of CCAs. The CPUC paper stated:

“A future in which CCAs procure electricity for a significant portion—perhaps even the majority—of IOU customers would present a number of questions that the CPUC must consider, including whether the current short- and long-term approach to procurement would need to be revisited, who would ensure reliability, cost allocation for reliability procurement and what entity or entities would be the ‘provider of last resort’.”
A Central Coast Power CCA could serve a significant portion of PG&E and SCE load, 3.7% and 6.4% respectively. Evaluating the changing CCA landscape will be important as the region considers further pursuit of a CCA.

In its background paper, the CPUC also discusses concerns centered on the large number of communities exploring CCA. The CPUC is reviewing the associated issues through the reopened Order Instituting Rulemaking to Implement Portions of AB117 Concerning Community Choice Aggregation Proceeding 03-01-003. The perspective of the IOU joint utilities (SDG&E, SCE, and PG&E) on many of the issues outlined in this section is summarized in their Update on Customer Choice in California and Portfolio Allocation presentation from January 2017. Figure B-45 is from an IOU joint utility PAM Presentation and depicts the potential customer and load departure due to CCA.

![Figure B-2 Copy of slide 5 of Joint Utility PAM Presentation](image)

Potential Customer And Load Departure Could Be Up To ~80%

The California CCAs have formed the California Community Choice Association (CalCCA) to represent them in the legislature and at the relevant regulatory agencies (CPUC, CEC and California Air Resources Board). Membership in CalCCA may help Central Coast Power mitigate the risk of unknown changes by providing both advocacy assistance and insight into what other CCAs are doing.

3.2. Exit Fees and Other Non-bypassable Charges from IOUs

As communities of varying size consider CCA implementation, the CPUC is examining the impacts on specific costs for relatively small communities as well as the larger metropolitan areas of California,
including San Francisco and San Diego as well as Los Angeles County and the Central Coast Tri-County region. A major risk when creating a CCA, particularly one that serves a large municipality or multiple municipalities, comes from costs transferred to the CCAs from the incumbent IOUs. Regarding rate competitiveness, forecasted Central Coast Power CCA revenue requirements are primarily driven by power procurement costs and the Cost Responsibility Surcharge (CRS), which consists of the Competitive Transition Charge (CTC), the Department of Water Resources Bond Charge (DWR-BC), and the Power Cost Indifference Adjustment (PCIA).

The primary role of the CPUC in the CCA process is to ensure that regulated IOUs provide required services to both the CCA and its customers. At the same time, the CPUC ensures that costs incurred by the IOU and caused by CCA customers are not passed along to “bundled” IOU customers and that CCA customers are paying only for the costs they cause. Currently, these costs are recovered through customer CRS charges, the largest component of which is the PCIA. These fees help recover the cost of the IOU’s energy procurement and service incurred on behalf of departing CCA customers.

In their role as LSEs, the IOUs have entered into medium- and long-term PPAs to meet the needs of their customers with a diversified supply portfolio. This includes PPAs to meet RPS obligations. In the case of Central Coast Power, up to 6.4% of SCE annual energy sales and 3.7% of PG&E annual energy sales would transition to a Central Coast Power CCA. As a result, the IOU's existing PPAs could become “stranded costs”—investments in infrastructure or long-term agreements—which are only recoverable to the IOU through exit fees. These fees would be charged directly to CCA customers as part of a service agreement. Tables B-1 and B-2 provide the current CRS by rate class as of March 1, 2017, as used in the pro forma analysis. However, should the Central Coast Power CCA go forward, it would likely see PCIA and CRS fees increase, perhaps materially, as discussed further in this section.

Table B-1 PG&E CCA CRS by Rate Class as of March 1, 2017

<table>
<thead>
<tr>
<th>Rate Group</th>
<th>DWR-BC Loss Energy Recovery Amount Charge</th>
<th>CTC</th>
<th>PCIA (2017 Vintage)</th>
<th>Total CRS Cost</th>
<th>CCA Generation Rate, Avg Jurisdictions RPS Equivalent Scenario</th>
<th>CRS % of Generation Rate</th>
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</thead>
<tbody>
<tr>
<td>Agriculture, PG&amp;E</td>
<td>$0.0055</td>
<td>$0.0010</td>
<td>$0.0213</td>
<td>$0.0278</td>
<td>$0.1200</td>
<td>23%</td>
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<td>Very Large Comm &gt;1000KW, PG&amp;E</td>
<td>$0.0055</td>
<td>$0.0007</td>
<td>$0.0153</td>
<td>$0.0215</td>
<td>$0.1100</td>
<td>20%</td>
</tr>
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<td>Large Comm 500-1,000KW, PG&amp;E</td>
<td>$0.0055</td>
<td>$0.0010</td>
<td>$0.0189</td>
<td>$0.0252</td>
<td>$0.1100</td>
<td>23%</td>
</tr>
<tr>
<td>Med Comm 200-500KW, PG&amp;E</td>
<td>$0.0055</td>
<td>$0.0010</td>
<td>$0.0225</td>
<td>$0.0290</td>
<td>$0.1200</td>
<td>24%</td>
</tr>
<tr>
<td>Small Comm 200-500KW, PG&amp;E</td>
<td>$0.0055</td>
<td>$0.0008</td>
<td>$0.0220</td>
<td>$0.0285</td>
<td>$0.1200</td>
<td>24%</td>
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<tr>
<td>Lighting, PG&amp;E</td>
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<td>$0.0002</td>
<td>$0.0092</td>
<td>$0.0099</td>
<td>$0.1000</td>
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<td>Residential, PG&amp;E</td>
<td>$0.0055</td>
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<td>$0.0292</td>
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<td>Residential CHP, PG&amp;E</td>
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<td>$0.1200</td>
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<td>Traffic Control, PG&amp;E</td>
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<td>22%</td>
</tr>
</tbody>
</table>

Notes
[1] Effective rates as of January 1, 2017
The implication for the Central Coast Power CCA is that even if the CCA’s primary power supply portfolio were cost-competitive with the existing supply costs, added PCIA and other exit fees may increase the overall costs such that the CCA’s offering would ultimately not be competitive with the IOU. This is especially true when considering the amount of load currently under consideration for CCA. One possible mitigation strategy for PCIA would be for Central Coast Power CCA to work with the incumbent utilities to purchase the excess renewable generation PPAs. The procurement of excess IOU RPS contracts potentially would both reduce the IOUs’ stranded costs and assist in developing Central Coast Power’s renewable generation portfolio.

A note about nuclear decommissioning: In addition to PCIA and CRS fees, IOUs have the ability to impose other charges on customers for reasons other than PPA and generation-related stranded costs. For example, SCE and SDG&E are partners on the San Onofre Nuclear Generation Station, which is in the process of early decommissioning. Additionally, PG&E has applied to decommission the Diablo Canyon nuclear power station. IOU customers have contributed money toward decommissioning these nuclear power plants since the facilities first opened. However, these early decommissionings have created the need for accelerated funding. Future increases in the PCIA fee may be imposed on CCA customers based on such decommissioning costs. In theory, decommissioning costs should not influence CCA rate competitiveness as they apply to both CCA and bundled customers.

Even before the completion of this Central Coast Power CCA feasibility study, the IOU joint utilities (SCE, PG&E, and SDG&E) are considering the implications of departing load and have initiated contact with the CPUC and operational and in-development CCAs to discuss potential paradigm shifts in the PCIA charge. As stated in an ex parte communication on February 28, 2017:

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Table B-2 SCE CCA CRS by Rate Class as of March 1, 2017

<table>
<thead>
<tr>
<th>Rate Group</th>
<th>Description</th>
<th>DWP-RC Loss Energy Recovery Amount Charge</th>
<th>CTC</th>
<th>PCIA (2017 Vintage)</th>
<th>Total CRS Cost</th>
<th>CCA Generation Rate, AWG Jurisdictions RPS Equivalent Scenario</th>
<th>CRS % of Generation Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Agriculture, SCE</td>
<td>$0.0005</td>
<td>$0.0002</td>
<td>$0.0040</td>
<td>$0.08093</td>
<td>$0.1326</td>
<td>7%</td>
</tr>
<tr>
<td>2</td>
<td>Very Large Comm &gt;1,000kW, SCE</td>
<td>$0.0005</td>
<td>$0.0002</td>
<td>$0.0040</td>
<td>$0.00393</td>
<td>$0.1299</td>
<td>7%</td>
</tr>
<tr>
<td>3</td>
<td>Large Comm 500-1,000kW, SCE</td>
<td>$0.0005</td>
<td>$0.0002</td>
<td>$0.0040</td>
<td>$0.08099</td>
<td>$0.1313</td>
<td>8%</td>
</tr>
<tr>
<td>4</td>
<td>Med Comm 200-500kW, SCE</td>
<td>$0.0005</td>
<td>$0.0002</td>
<td>$0.0039</td>
<td>$0.01025</td>
<td>$0.1226</td>
<td>9%</td>
</tr>
<tr>
<td>5</td>
<td>Small Comm &lt;200kW, SCE</td>
<td>$0.0005</td>
<td>$0.0003</td>
<td>$0.0050</td>
<td>$0.0111</td>
<td>$0.1240</td>
<td>9%</td>
</tr>
<tr>
<td>6</td>
<td>Lighting, SCE</td>
<td>$0.0005</td>
<td>$0.0001</td>
<td>$0.0050</td>
<td>$0.0129</td>
<td>$0.1285</td>
<td>10%</td>
</tr>
<tr>
<td>7</td>
<td>Residential, SCE</td>
<td>$0.0000</td>
<td>$0.0003</td>
<td>$0.0078</td>
<td>$0.0078</td>
<td>$0.1277</td>
<td>6%</td>
</tr>
<tr>
<td>8</td>
<td>Residential CSGP, SCE</td>
<td>$0.0000</td>
<td>$0.0003</td>
<td>$0.0078</td>
<td>$0.0078</td>
<td>$0.1277</td>
<td>6%</td>
</tr>
<tr>
<td>9</td>
<td>Traffic Control, SCE</td>
<td>$0.0005</td>
<td>$0.0002</td>
<td>$0.0035</td>
<td>$0.0088</td>
<td>$0.1290</td>
<td>7%</td>
</tr>
</tbody>
</table>

Notes:
[1] Effective rates as of January 1, 2017
In that ex parte communication, the joint utilities discussed a PCIA replacement methodology, which they refer to as a portfolio allocation method (PAM). According to that communication, “Portfolio Allocation Method replaces inaccurate and contentious administrative prices with true market valuation and an allocation of attributes and is increasingly important with higher levels of load departure.”

The CalCCA “supports legislation and regulatory policies that benefit CCA customers,” lists among its platform objectives for 2017 to “Prevent new non-bypassable charges and phase out or eliminate existing non-bypassable charges.” Among the other platform objectives is one to “increase transparency of inputs to PCIA and all non-bypassable charges…” The regulatory movement with respect to PCIA and other non-bypassable charges should be closely monitored if Central Coast Power maintains an interest in developing a CCA.

The uncertainties regarding future surcharges administered to CCA constituents for stranded costs and around RPS and RA credits are significant risks in considering moving forward with CCA. This potential risk should be further evaluated, with a focus on better understanding the potential stranded contract volume/cost as well as the potential for restructuring those supply contracts.

### 3.3. Customer Opt-Outs and Other Reductions in Energy Sales

The Central Coast Power CCA should consider the risk of customer opt-Outs after the CCA becomes operational. Like IOUs, CCAs face the risk of stranded costs due to loss of sales after their PPAs have been signed. If the customer returns to IOU service after the post-enrollment opt-out period, they are then placed on IOU Bundled Portfolio Service. The risk is that power the CCA procured over a longer-term would no longer be required to serve CCA load, and that power may have to be sold on the market at a loss. With the growth of DER in general, and roof-top solar PV in particular, the CCA should also closely monitor DG penetration, which will reduce daytime load.

Keys to keeping customers engaged and loyal to the CCA include positive customer experiences, highly valued product(s) and services, and economic advantage. Implementation and operational plans should focus on these objectives.

Another mitigation step is performing a periodic check of CCA supply portfolio position relative to the current energy market to determine what the liquidation cost might be with various levels and timing of customer opt out and/or other departing load. This exercise can monetize the potential exposure and Central Coast Power can take mitigation steps, such as using a reserve fund, that mitigates the negative effects of the potential open position should customer load drop off substantially. This approach, along with other proactive risk identification, assessment, and mitigation plans should be part of an overall risk management plan, some of which should start to be developed during the implementation study phase and further developed as part of the risk management strategy for particular, selected energy suppliers.
4. Ratemaking Principles

A CCA operates in a market that is defined by very limited competition. Currently, as DA has been suspended, a potential CCA customer has two choices for energy supply service: the CCA or its IOU. These types of low-competition markets—sometimes referred to as “natural monopolies”—have long been regulated to protect customers from unfair pricing, to ensure reliable and safe operation of the electric grid, and to allow for necessary investments in generation, transmission, and distribution. This section provides an overview of rate setting principles that apply to IOUs and utilities owned by public agencies. These principles would inform rate design and setting for a CCA program.

In his seminal 1961 book “Principles of Public Utility Ratemaking,” James C. Bonbright established foundational ratemaking principles and provided supporting economic theories and regulatory policies. This book continues to be primary reference sources for those involved in revenue requirement, cost of service, and rate design analyses and policy. Bonbright seeks to answer a seemingly simple question that often lacks simple answer: “In the absence of a competitive market, how does one establish fair and reasonable rates?”

Bonbright’s principles can be distilled as follows:

- Rates should be practical—simple, understandable, acceptable, and feasible to apply
- Rates should be uncontroversial as to interpretation—precise, clearly written, and with no ambiguity
- Rates should be effective in meeting revenue requirements—generate revenues sufficient to cover the utility’s revenue requirements
- Rates should be stable from a revenue perspective—not change frequently and/or extremely, i.e., generate a stable income
- Rates should be stable from a rate perspective—customer bills should not change frequently and/or extremely, i.e., customers should be able to anticipate what their monthly bill will be
- Rates should exhibit fairness among customer classes—subsidies occurring between classes should be kept to a minimum, again relying on cost based rates
- Rates should exhibit avoidance of undue discrimination—no individual ratepayer, group of ratepayers, or rate class should suffer an undue burden or punitive ratemaking policies
- Rates should be efficient economically—rates discourage the wasteful use of resources and promote an optimal offering of services

According to Bonbright, given the lack of market competition, a monopoly enterprise is entitled to recover its costs plus a reasonable return on investment. Cost of service, therefore, is the basic standard of reasonableness and fairness; and ratemaking has long been grounded in the concept of charging utility customers “cost based rates.” The concept is straightforward: individual customers pay the cost they impose on the system for service. While cost-based rates are grounded on Bonbright’s common sense, foundational ratemaking principles, the application of these principles can vary widely. What is considered fair and reasonable largely depends on individual perspective and outcomes.
No matter the utility, the fundamentals of cost of service are relatively constant and revolve around: equity and fairness, reasonableness and adequacy of rates to support prudent business practices, and social objectives. However, often because of competing objectives and other issues, rates will result in intra- and/or inter-customer class subsidization—meaning certain customers are paying less than their full cost of service, while other customers pay more than their cost of service to make up the shortfall. This Study has not reviewed or assessed existing cost of service analyses for PG&E and SCE customer classes, and makes no opinion as to any intra- or inter-class subsidizations that may be occurring.

Bonbright strongly disagreed with the use of rates for social engineering. His principles, therefore, do not include mechanisms for behavior modification, ability to compete, or responsiveness to social issues. However, in practice, modern rates are often driven by such considerations that create additional layers of complexity and design tension. These inherent ratemaking conflicts almost always necessitate balancing principles, good rate design, and compromise. As such, experience, judgment, precedent, and reasonableness all become critically important elements of the ratemaking process.
5. Notes

1 The exception to this is if customer output from a DER exceeds the customer’s annual usage. In that case, an LSE can procure the excess as RPS-compliant Renewable Energy Credit (REC).


3 SCE energy efficiency programs: https://www.sce.com/wps/portal/home/business/savings-incentives/express-solutions/

4 PG&E energy efficiency programs: http://www.pge.com/myhome/environment/pge/energyefficiency/

5 SCE demand response programs: https://www.sce.com/wps/portal/home/business/savings-incentives/demand-response


7 California Public Utilities Code - Section 381.1 http://codes.lp.findlaw.com/cacode/PUC/1/d1/1/2.3/7/s381.1

8 emPower Central Coast: https://www.empowersbc.org

9 https://www.mcecleanenergy.org/energy-savings/

10 CPUC Decision 12-11-015 Approving 2013-2014 Energy Efficiency Programs and Budgets, November 15, 2012: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M034/K299/34299795.PDF


12 CPUC Decision 15-07-001 July 3, 2015: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K110/153110321.PDF

13 California Decision 14-03-026 Addressing Foundational Issue of the Bifurcation of Demand Response Programs, April 4, 2014: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K480/89480849.PDF


18 Plug In America - Understanding Electric Vehicle Charging: https://pluginamerica.org/understanding-electric-vehicle-charging/

19 CEC Rule 21 Smart Inverter Working Group Technical Reference Materials:
Appendix B
Additional Study Detail

http://www.energy.ca.gov/electricity_analysis/rule21/


20 Reference Smart Grid Interoperability Panel (SGIP) Catalog of Standards (CoS) listing for SAE J1772-2010, SAE J2836 Use Cases (1-3), and SAE J2847-1: http://www.gridstandardsmap.com/


22 Sonoma Clean Power – Drive Electric: https://sonomacleanpower.org/drive-electric/


24 SCE Overview of Generation Interconnections: https://www.sce.com/gridinterconnection


26 Lancaster ChoiceEnergy offers a program called “Personal Choice” for customers with solar or wind power resources located behind the SCE customer meter: http://www.lancasterchoiceenergy.com/your-options/personal-choice/


28 CPUC Interconnection Rule 21: http://www.energy.ca.gov/electricity_analysis/rule21/

29 http://www.energy.ca.gov/electricity_analysis/rule21/


33 Southern California Edison Company’s (U 338-E) Notice Of Ex Parte Communication, January 27, 2017: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M175/K252/175252576.PDF


35 California Community Choice Association: http://cal-cca.org/

SCE%20Ntc%20Ex%20Parte%20Communication%20(2-23-17).pdf

37 Ex parte communication regarding PCIA and portfolio allocation methodology:

38 SCE The CCA Handbook Chapter 17 Post-Enrollment Opt-Out, Re-Entry, and Switching Exemptions Version 3.0

39 Highly valued products and services refer not only to the various “green” products offered but also the overall
tone, objective, and longer-term strategies of the CCA program, including successful development of economic
local renewables, innovative energy efficiency programs, and opportunities and evidence of local direct and
indirect job growth.

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