Community Choice Aggregation

Base Case Feasibility Evaluation

County of San Diego

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EXECUTIVE SUMMARY

This report offers Navigant Consulting, Inc.'s (NCI) evaluation of the feasibility of forming a Community Choice Aggregation program, pursuant to provisions of Assembly Bill 117, whereby the County would aggregate the electric loads of customers within the unincorporated areas of the County for purposes of procuring electrical services. Community Choice Aggregation relates to electric generation services only. Delivery of the electric power would continue to be provided over SDG&E transmission and distribution facilities at rates regulated by the California Public Utilities Commission (CPUC) and under the same terms and conditions that apply today. Community Choice Aggregation allows the County to provide retail generation services to customers without the need to acquire transmission and distribution infrastructure. All SDG&E customers within the County would have the option of buying electricity from the County or, alternatively, remaining as generation customers of SDG&E by exercising their rights to opt-out of the program.

AB 117 grants the County authority to competitively procure electric services rather than continuing to rely on SDG&E as the single supplier for electric services provided to customers within the County. Implementation of Community Choice Aggregation provides the community the power to choose what resources will serve their loads. Expanded access to competitive suppliers and local control of resource planning decisions provide opportunities to enhance rate stability for customers, significantly increase utilization of renewable energy resources, and generate electricity cost savings.

The detailed analysis performed for the County suggests that by forming a Community Choice Aggregation program, backed by investments in generation resources, the County could obtain the following benefits:

- Achieve nominal electricity cost savings averaging approximately $25.3 million per year over the next 20 years, equivalent to approximately 5% of total electricity bills;
- Increase renewable energy utilization to 40% by 2017, more than doubling the renewable energy content that SDG&E is required to provide over the same time period;
- Obtain control over electric generation costs to provide a higher level of rate stability for local residents and businesses; and
- Improve statewide and local reliability by increasing capital investment in generation plants.

Under the base case assumptions, ratepayer benefits would begin to accrue in the fifth year of program operations, assuming a 2006 implementation date and no changes in the current rate designs of SDG&E. During the initial four years of program operations, program costs would likely exceed the equivalent rates charged by SDG&E due to the requirement that Community Choice Aggregation customers pay a separate surcharge ("cost responsibility surcharge") to SDG&E. If the County initiated a Community Choice Aggregation program in 2006, it would likely have to charge slightly higher rates (1% to 2%) in the initial years of the program, or it would need to finance approximately $34 million of accumulated losses during the four-year start-up period. Because customers would have the ability to opt-out of the Community Choice Aggregation program, charging higher rates than SDG&E is likely not a viable option. Implementing a Community Choice Aggregation program in phases would reduce the need for startup financing and generally minimize implementation risks. The County could phase-in implementation of the Community Choice Aggregation program to reduce its program startup costs and help ensure a smooth transition for customers that join the program. Alternatively, the County could delay implementation to the 2008 or 2009 timeframe to avoid the next few years during which the cost responsibility surcharges will be the highest.

Notwithstanding the near-term challenges created by SDG&E's imposition of the cost responsibility surcharges on Community Choice Aggregation customers, the scenario analysis conducted for this study shows moderate cost savings are likely over the long-term under most reasonable sensitivity cases. The average program savings range from a low of 1% to a high of 10% across the seven cases evaluated to test the sensitivity of the base case results to changes in wholesale energy market conditions, SDG&E rate projections, and cost responsibility surcharges. However, under the base case and five of the sensitivity cases examined, program rates would be from 1% to 2% higher than those of SDG&E within the initial four years of program operations. In the "worst case" (an assumed increase in the cost responsibility surcharge of 50%), program rates would be 4% to 7% higher than those of SDG&E during the early years of the program.

One noteworthy sensitivity case is the impact of SDG&E's proposals to modify its electric rate designs, currently being considered by the CPUC in the SDG&E Rate Design Window proceeding. SDG&E's rate proposals would improve the near and long-term economic viability of a County Community Choice Aggregation program because their adoption would tend to raise the generation rates paid to SDG&E by electric customers within the County. If SDG&E's proposals are ultimately adopted by the CPUC, NCI expects that the County's Community Choice Aggregation program would begin producing surpluses by the second year of program operations, all other factors being equal. Because of the importance of this regulatory event to the near-term viability of a County Community Choice Aggregation program, NCI recommends that the County closely monitor the SDG&E Rate Design Window Proceeding and evaluate whether to proceed toward implementation of a Community Choice Aggregation program once the outcome of that proceeding is known in early 2006.

Energy procurement and resource planning are subject to certain risks or uncertainties that must be managed by the energy supplier, whether it is SDG&E or the operator of a Community Choice Aggregation program. Forming a Community Choice Aggregation program would not increase energy procurement risks, but responsibility for their management would transfer to the Community Choice Aggregator and/or its suppliers. The County will be able to obtain services from a variety of large, experienced suppliers to help manage the Community Choice Aggregation program. The County would exercise a greater degree of autonomy in its energy procurement activities than SDG&E is allowed under current regulations. The County should therefore be able to manage energy procurement risks at least as effectively as does SDG&E. Professional program management and application of standard industry risk management practices will be keys to this effort.

The County could implement its Community Choice Aggregation program alone or through formation of a joint powers agency (JPA) with other local governments. Formation of a regional program through the JPA provides economies of scale that enhance the economic benefits available to the County through Community Choice Aggregation. The JPA structure also provides an appropriate financing vehicle for the capital investments needed to support a cost-effective aggregation program.

The base case feasibility analysis contains conservative assumptions regarding the future direction of SDG&E's generation rates, which are the reference points for estimating the economic benefits of forming a Community Choice Aggregation program. For purposes of this analysis, SDG&E's rates are projected to decline in real terms (adjusted for inflation) during the 20-year forecast period. In nominal terms, SDG&E's rates are projected to increase by an average annual rate of 2.4%, which is consistent with historical trends. The financial projections are particularly sensitive to the future direction of SDG&E

rates. As shown in the sensitivity cases, if SDG&E generation rates were to increase by an average of 3% per year rather than the 2.4% projected in the base case, the financial benefits of the Community Choice Aggregation program would approximately double (from 5% to 10%).

Whereas all current CPUC decisions are reflected in the feasibility assessment, the CPUC is still in the process of finalizing certain detailed rules and protocols that will apply to Community Choice Aggregation. The ongoing phase of the CPUC rulemaking is focused on operations and transactional issues that will be important to a Community Choice Aggregation program's operations but that are unlikely to materially impact the base case feasibility assessment presented herein. NCI expects the CPUC rulemaking to be completed by the end of 2005.

LIST OF ACRONYMS

A&G – Administrative and General
AB 1890 – Assembly Bill 1890
AB 117 – Assembly Bill 117
CAISO – California Independent System Operator
CCA – Community Choice Aggregation
CEC – California Energy Commission
CPUC – California Public Utilities Commission
CRS – Cost Responsibility Surcharge
CTC – Competition Transition Charge
DG – Distributed Generation
DWR – Department of Water Resources
FERC – Federal Energy Regulatory Commission
GRC – General Rate Case
IOU – Investor Owned Utilities
IT – Information Technology
JPA – Joint Powers Agency
KW - Kilowatt
KWh – Kilowatt hour
MW – Megawatt
MWh – Megawatt hour
NOPEC – Northern Ohio Public Energy Council
NOx – Nitrogen Oxides
NP15 – North of Path 15
O&M – Operations and Maintenance
PG&E – Pacific Gas and Electric Company
PTC – Production Tax Credit
PUC – Public Utilities Code
PUCO – Public Utilities Commission of Ohio
PV - Photovoltaic
QF – Qualifying Facilities
RE – Renewable Energy
REC – Renewable Energy Certificate
RPS – Renewable Portfolio Standard
RRDR – Renewable Resource Development Report
SCE – Southern California Edison Company
SDG&E – San Diego Gas and Electric Company
SEP – Supplemental Energy Payment
VEE – Verification, Editing and Estimation

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1 INTRODUCTION

1.1 Objective

The County is a participant in the Community Choice Aggregation Demonstration Project, which was commissioned by the California Energy Commission (CEC) and the United States Department of Energy to assist local governments in evaluating and implementing Community Choice Aggregation, whereby the County would aggregate the electric loads of customers within the County for purposes of procuring electrical services.

The purpose of this report is to evaluate the feasibility of the County forming a Community Choice Aggregation Program. The report contains detailed economic feasibility analyses and recommendations to help the community evaluate the costs and benefits afforded by Community Choice Aggregation and move towards development of an Implementation Plan.

The report and analyses contained herein comprise project deliverable Task 4: Load Analysis and CPUC Decision Based Feasibility Analysis for the CEC-funded Community Choice Aggregation Pilot Project. This report builds upon the Load Analysis and Assumptions Based Feasibility Analysis previously provided to the County, which presented economic feasibility results for a CCA program utilizing four alternative supply portfolios. Upon review of the preliminary results, the County provided input on its preferred supply portfolios with respect to the percentage of its supply it desires to be produced from renewable energy resources and whether the County intends to utilize its municipal financing capabilities to reduce the costs of is electricity procurement program by financing energy development projects. These supply preferences and other feedback received from the County staff are reflected in this final report. This report additionally incorporates the CPUC's December 16, 2004 decision in Phase 1 of the CCA rulemaking (Decision No. D.04-12-046).

As second phase of the Demonstration Project will include the development of a template for use by communities in developing Implementation Plans for submission to the California Public Utilities Commission (CPUC). Project funding is available to offset the costs of creating the template. Communities can utilize the template to develop the specific Implementation Plan for their CCA program.

1.2 Project Elements And Timeline

NCI recommends a two-phased approach for consideration of forming a CCA program. The current Phase 1 includes the base case feasibility study and report, while Phase 2 includes development of an Implementation Plan for submittal to the CPUC. A high level overview of these phases is shown below:

Phase 1 Element	Timeline
Community Selection	Complete
Participant Orientation	Complete
Renewable Resources Workshop	Complete
Base Case Feasibility Analysis	Complete
Participation in CPUC CCA Rulemaking Phase 1	Complete
Draft Evaluation and Report	Complete
Final Feasibility Analysis	March 2005
Final Evaluation and Report	March 2005

Phase 2 Element	
Development of Implementation Plan Template	Ongoing
Participation in CPUC CCA Rulemaking Phase 2	Jan. 2005 – Jul. 2005
Prepare and Submit Implementation Plan	Fall 2005
Support Implementation Plan Filing At CPUC	Fall 2005

1.3 Phase 2 - Implementation Plan

After considering the expected benefits and costs of forming a CCA program, communities that wish to proceed with forming a CCA program will need to develop an Implementation Plan. AB 117 requires submission of an Implementation Plan to the CPUC prior to the CCA commencing operations. The law requires the Implementation Plan to "detail the process and consequences of aggregation." The Implementation Plan and subsequent changes to it must be adopted at a duly noticed public hearing. The Implementation Plan must contain all of the following:

- An organizational structure of the program, its operations, and its funding.
- Ratesetting policies and other costs to participants;
- Provisions for disclosure and due process in setting rates and allocating costs among participants;
- The methods for entering and terminating agreements with other entities;

- The rights and responsibilities of program participants, including, but not limited to, consumer protection procedures, credit issues, and shutoff procedures;
- Termination of the program; and
- A description of the third parties that will be supplying electricity under the program, including, but not limited to, information about financial, technical, and operational capabilities.

A CCA must prepare a statement of intent with the Implementation Plan. Any CCA program shall provide for the following:

- Universal access
- Reliability
- Equitable treatment of all classes of customers
- Any requirements established by state law or by the CPUC concerning aggregated service

The California Public Utilities Commission has responsibility to review the Implementation Plan submitted by an Aggregator, and it may establish additional detail regarding the form and content of an Implementation Plan in Phase 2 of R.03-10-003.

2 OVERVIEW OF CCA

2.1 What Is CCA?

Assembly Bill 117 permits California cities, counties, or city and county joint powers agencies ("local governments"), to implement a program to aggregate the electric loads of electric service customers within their jurisdictional boundaries to facilitate the purchase and sale of electricity. The local government would become a Community Choice Aggregator ("Aggregator") to procure electric energy for residents and businesses within a community. All customers currently receiving electric generation services from SDG&E would be automatically enrolled in the program, unless the customer notifies the County of its desire to opt-out and remain a bundled service customer of SDG&E. The County would be responsible for operating the CCA program, either by performing the functions necessary for program operations utilizing its own employees or by contracting out operations to one or more third-party operators or energy services providers.

Within the context of CCA, "electricity" means the electric energy commodity only. CCA's enabling legislation requires local utilities such as SDG&E to provide electricity delivery over its existing distribution system and provide end-consumer metering, billing, collection and all traditional retail customer services (i.e., call centers, outage restoration, extension of new service). 1 Accordingly, the infrastructure requirements of the CCA program do not include any electric transmission or distribution related facilities to serve CCA retail loads. SDG&E must provide delivery services to CCA customers under the same terms and conditions as provided to other of its customers.

It is important to distinguish an Aggregator from municipal utilities and from energy service providers as each of these entities provides different services, has different responsibilities, and operates under different regulatory frameworks. A local government that implements a community choice aggregation program does not become a municipal utility in the manner of the Los Angeles Department of Water and Power or the Sacramento Municipal Utility District, which own and operate transmission and distribution systems. A critical

[1] The CCA will also provide customer service functions to disseminate program information, respond to customer inquires, conduct customer notifications for the opt-out process, and conduct other customer account management functions related to the CCA program.

distinguishing factor is that the County would not own the electric distribution system within the County. Rather, it would own or procure electric power from the wholesale markets, either through ownership of resources, market purchases, or through a partner on behalf of the customers that choose to aggregate their loads. The local investor owned utility (SCE, PG&E, or SDG&E) would then be required to deliver the electric energy to the end-use customer across its transmission and distribution facilities. In this sense, an Aggregator is similar to an electricity service provider that sells electricity to direct access customers. However, there are important differences between CCA and direct access, and these two programs will operate under different sets of rules established by the CPUC.

Customers of the CCA will pay the same charges for delivery (transmission and distribution) as customers that remain as full service, "bundled" customers of SDG&E. Customers will receive a single bill from SDG&E that includes SDG&E's delivery charges and the CCA's charges. These delivery charges represent approximately one half of the typical household's monthly electric bill. The County will establish rates for the generation services it provides to CCA customers, and these customers will no longer pay SDG&E for generation services. However, SDG&E will be authorized to assess a surcharge for certain of its generation related costs that might otherwise be shifted to its remaining bundled service customers. This surcharge is known as the "cost responsibility surcharge" or "CRS", and it will be regulated by the CPUC. The cost responsibility surcharge is discussed in greater detail in Section 5.3.2.

By law, SDG&E will perform all metering and billing for CCA customers. SDG&E will collect the County's charges from CCA customers and transfer the funds collected to the County in the monthly billing process. To a large extent SDG&E's costs of providing metering, billing and customer services are included in their existing delivery charges. However, the utilities have asserted that CCA programs will cause additional costs related to metering, billing and customer services, and they have requested the CPUC to authorize additional charges to be assessed on Aggregators or CCA customers. This and other issues in the CPUC Rulemaking are discussed in Section 2.3.

2.2 Legal And Regulatory Authority

A CCA program for electric customers is governed by the Community Choice Aggregation legislation (AB 117, Chapter 838, September 24, 2002[2]). A local government could become an Aggregator for electric utility generation by passing legislation declaring itself to be a CCA and developing an Implementation Plan for submission to the CPUC. AB 117 creates an important opportunity for the success of CCA by requiring that customers "opt-out" of the CCA program rather than "opt-in". This allows the County to sign up customers willing to switch from SDG&E generation service to CCA service without the necessity of developing an active marketing effort to reach every customer. Instead, the County would merely need to notify customers of the impending Community Choice Aggregation program. Any customers that do not want to participate in the program would be required to notify the County of their election to opt-out within a specified amount of time. Customers opting out during the initial period would not be subject to penalty of any kind. Customers choosing to exit the program after the initial opt-out period may be subject to exit fees imposed by the CCA and/or re-entry fees imposed by SDG&E.

AB 117 also requires full cooperation by the host investor owned utility in any CCA program implemented by the County. In this regard, AB 117 would require SDG&E to provide necessary load information and other important data and continue to provide transmission, distribution, metering, meter reading, billing and other essential customer services.

2.2.1 Requirements After Filing The Implementation Plan

1. Within 10 days after the Implementation Plan is filed, the CPUC will notify SDG&E (PUC Section 366.2(c)(6)).

2. Within 90 days after the County files an Implementation Plan the CPUC shall certify that it has received the Implementation plan, including any additional information necessary to determine a cost recovery mechanism. The Commission shall designate the earliest possible date for implementation of a CCA program (PUC Section 366.2(c)(7)).

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[2] AB 117 became effective January 1, 2003 amends Sections 218.3, 366, 394, and 394.25 of the Public Utilities Code and creates Sections 331.1, 366.2, and 381.1 to the same Code.

3. The County must offer the opportunity to purchase electricity to all residential customers within its political boundaries (PUC Section 266.2(b)).[3]

4. SDG&E shall fully cooperate with the County, including providing appropriate billing, and electrical load data, in accordance with CPUC procedures (PUC Section 366.2(c)(9)).

5. The County must fully inform all customers of their right to opt-out of the CCA program and to continue to receive service as a bundled customer from SDG&E. All customers must be notified twice within two months or 60 days prior to the date of automatic enrollment. In addition, notification must continue for participating customers for at least two consecutive billing cycles after enrollment (PUC Section 366.2(c)(11),(13).

6. Notification must contain the following information:
   - Customer will be automatically enrolled;
   - Each customer has the right to opt-out of the program without penalty; and
   - The terms and conditions of CCA service (PUC Section 366.2(13)(A)).

7. The County may request the Commission to approve and order SDG&E to provide the customer notifications (PUC Section 366.2(13)(B)).

8. The County must register with the CPUC and may be required to provide additional information in order to verify compliance with rules for consumer protection and other procedures (PUC 366.2(c)(14)). At the time of registration, the County must post a bond or provide evidence of sufficient insurance to cover any reentry fees that may be imposed against it by the CPUC for involuntarily returning a customer to service of SDG&E (PUC Section 394.25(e)).

9. The County must notify SDG&E that CCA service will begin within 30 days (PUC Section 366.2(c)(15)).

[3] However, the CCA may implement its program in stages as discussed in Section 4.1.5.

10. Once notified, SDG&E shall transfer all applicable accounts to the new supplier within a 30-day period from the date of the close of their normally scheduled monthly metering and billing process (PUC Section 366.2(c)(16)).

11. SDG&E shall recover from the County any costs reasonably attributable to the County, as determined by the CPUC (PUC Section 366.2(c)(17)).

2.3 Status Of CPUC Rulemaking

While AB 117 does provide a statutory basis for Community Aggregation projects, the CPUC has not yet developed and implemented final rules for the development of such programs. On September 4, 2003, the CPUC issued an order instituting a rulemaking or "OIR" (Rulemaking 03-09-007) in order to develop the guidelines for community aggregation programs, as it was directed to do under AB 117. On October 2, 2003, the CPUC reissued the rulemaking under Docket No. R.03-10-003. The CPUC bifurcated the proceeding into two phases. The scope of Phase 1 was to determine issues related to costs imposed by the local utilities on Aggregators and CCA customers, namely cost responsibility surcharges, transaction fees, and implementation costs. The general scope of Phase 2 is to address the processes for interactions between Aggregators and the local utilities and other operational details. The issues identified with each phase are listed below:

2.3.1 Phase 1 Issues

- Cost responsibility surcharges – methodology, transparency, caps, new utility procurement, rate design, phasing, assumption of in lieu MWh
- Transactions costs - implementation fees, fees related to CCA establishment, enrollment fees, billing, payment and collection, monthly account maintenance fee, interval metering fee, termination of CCA program fee, special request fee, information fees
- Customer information issues – data needs of Aggregators, customer confidentiality protections

2.3.2 Phase 2 Issues

- The detailed processes, costs, and fees authorized for the utilities' CCA implementation activities and utility transactions with CCAs (e.g., metering, billing, CCA establishment, notifications, enrollments, account maintenance, termination)

- Rules and formats for notifying customers of CCA service and customer opt-out opportunities
- Rules for switching customers to CCA service, processing customer opt-outs, and returning CCA customers to utility service
- Customer reentry fees and bonding requirements imposed on CCAs
- CCA phase-in mechanisms and guidelines, including impacts on the cost responsibility surcharge
- CCA consumer protection obligations
- CCA Implementation Plan requirements

The Commission issued its final decision (D.04-12-046) in Phase 1 on December 16, 2004, and that phase is now completed. Phase 2 is expected to conclude in the third quarter of 2005.

2.4 Aggregation In Other States

Aggregation programs exist in both Massachusetts and Ohio, with the Ohio program being most similar to Community Choice Aggregation in California. Ohio includes provisions for government aggregation on an opt-in or opt-out basis. According to the Public Utilities Commission of Ohio (PUCO), Ohio has had among the most successful electric choice programs in the nation, with government aggregation leading the way.4 The greatest success is in those areas of Ohio that have adopted aggregation. Northern Ohio has experienced a high rate of customer switching due in large part to this process whereby communities band together to buy electricity, in bulk, for their residents. In the first two years of electric choice:

- More than 150 local governments passed ballot issues and were certified by the PUCO to allow local units of government to represent their communities in the competitive electricity market. Ohio is home to the Northeast Ohio Public Energy Council (NOPEC), the largest public aggregator in the United States. NOPEC represents 112 communities in eight counties and more than 350,000 residential customers.

[4] Information about the Ohio aggregation experience was obtained from The Ohio Retail Electric Choice Programs Report of Market Activity 2001-2002, A Report by The Public Utilities Commission of Ohio, May 2003.

Of those customers who have switched in Ohio[5], aggregation programs account for:

- Nearly 93% of residential customers who have switched in Ohio
- More than 88% of commercial customers who have switched in Ohio
- Nearly 20% of industrial customers who have switched in Ohio

NOPEC customers are able to opt out of the program every two years. NOPEC currently provides rates that provide a 6% discount off the generation portion of electricity bills for residential and governmental accounts and a 4% discount for commercial and small industrial accounts. The supply contract NOPEC negotiated with its energy provider, Green Mountain Energy, guarantees its electricity generation charges will always be less than the utility's generation charges. The electricity supplied through the NOPEC program is about 70% less polluting than the typical system power in Ohio.

2.5 Implementation Models

There are a variety of approaches the County could take in implementing a CCA program, varying in the degree of operational control, risk and benefits afforded to the County.

2.5.1 Single Third Party Supplier

At one end of the spectrum, the County could pursue a minimalist approach, essentially serving as a conduit between electric customers within the County and a third party electric supplier. The County would solicit offers from electric suppliers to serve the customers that choose to participate in the program (i.e., do not opt out) and would largely rely on the supplier to administer the program. An example would be for the County to negotiate a guaranteed discount to the prevailing SDG&E rate such that the supplier absorbs the risks of meeting the obligation to provide electricity cost savings. This approach offers very little risk to the County but also limits the potential upside, especially with respect to the benefits offered by municipal-financed generation assets or financing arrangements.6 Suppliers may not be willing to absorb the risks associated with factors that are outside the control of the supplier, such as those

[5] Remaining customer switching is attributable to non-government aggregation, such as direct access arrangements between energy suppliers and retail customers.

[6] It may be possible to negotiate agreements with the electric supplier to integrate municipal resources or utilize municipal bonding, but this would necessitate greater County involvement than represented by the pure minimalist approach outlined here.

posed by changes in SDG&E rates or the CRS. Furthermore, under the assumption that suppliers would not charge less than the market price of electricity as utilized in this analysis, the imposition of the CRS would appear to eliminate the opportunity for cost savings to be obtained in the near term. Indicative bids from electricity suppliers should be obtained early in the County's implementation planning to help determine whether this approach is financially viable.

2.5.2 Multiple Third Party Service Providers

In pursuing this approach, the County would "unbundle" the electric services needed for the program and negotiate contracts with third parties for provision of these discrete services (e.g., customer account services, scheduling coordination, electric supply). The County would assume overall responsibility for the program and for the performance of its contractors. The County would be responsible for setting rates and program policies and for general administration of the program. This approach offers several advantages, including limited staffing requirements, greater control, diffusion of risk (associated with supplier default), and the accumulation of industry knowledge and experience that creates strategic value at the County. Under this approach, the County would bear sole accountability for the results achieved by the program; regardless of whether these are successes or failures.

2.5.3 Municipal Operations

In the longer term, the County could create the organization needed to operate the CCA program, utilizing in-house staff and resources. Recruiting skilled professional staff with electricity operations experience would be a challenging endeavor in the near term and is probably not feasible for a planned 2006 start date. Over time, as the County gains experience with the program, some or all functions that were initially contracted out to third parties could be brought in-house, if desired.

2.5.4 Unilateral or Joint Operations

The County could implement a CCA program on its own or in combination with other cities and/or counties through a Joint Powers Agency (JPA). Clearly, there would be efficiencies and cost savings achieved by jointly implementing a single program. Such a combined program provides scale economies, improving terms of financing and power supply options. Customers would get the benefits of greater bulk buying power and professional expertise available through a larger organization. A larger organization would wield greater political influence and more effectively participate in the regulatory process to protect member interests. Individual implementation would require a greater investment of time and expense by the County, and would entail generally higher operations costs.

The primary disadvantages of implementation through a JPA are a joint program could reduce the degree of autonomy exercised by the County over its program and the JPA decision-making process can be cumbersome.7

[7] The individual members of the JPA could retain ratemaking authority, such that each community maintains its own tariffs applicable to customers within its jurisdiction.

3 BENEFITS OF CCA

The primary benefits offered by CCA are local control over the energy resources utilized by the community and the ability to either provide electricity to customers at a lower overall cost, increase revenues for public benefit programs, or a combination of the two. The cost savings can accrue to customers through lower electric bills or can be used by the County to provide enhanced services to its constituents. Local control manifests in a variety of benefits giving customers a means to effectuate their preferences regarding the type of electricity production they support as well as obtaining energy services that satisfy their unique needs. Through CCA, the County can choose to structure a supply portfolio that achieves cost efficiencies, fuel and technological diversity, environmental improvement, and/or cost stability. The County can choose to develop its own energy resources and decide which type of resources will be developed and where such resources should be located, consistent with its general planning responsibilities. New generation infrastructure developed to serve the CCA program can improve the reliability of the state's electric system.

CCA would facilitate the County's implementation of an aggressive program to increase utilization of renewable energy resources and promote improved energy efficiency. The County's local perspective and its primary mission to serve its customers rather than maximize profits for shareholders places it in a unique position to integrate effective demand-side energy efficiency programs with procurement of electricity supplies to lower overall energy costs for the community.

Generally speaking, the cost competitiveness of the CCA program will depend on the following factors:

- The quantity and mix of customers served by the County and the rate designs charged by SDG&E for the various customer classes
- The composite load profiles (hour-by-hour energy consumptions) of the County's customer portfolio
- The resource mix utilized by the County
- The use of low cost municipal bonds to finance generation resource projects
- Electricity prices and prices for other services negotiated with third party electric suppliers
- The trajectory of SDG&E's generation costs and whether all cost increases are passed on to CCA customers through the cost responsibility surcharge

- The costs charged by SDG&E for implementation activities and transactions such as metering, billing, and customer services.

A CCA program would enable the County to capture the benefits of competition among suppliers for the right to serve the community's load. California's experience with direct access showed that suppliers were willing to offer discounts to large customers of the investor owned utilities (IOUs). For the most part, discounted rates were not offered to residential customers because of their relatively small loads and the high marketing and transactions costs related to serving mass-market customers. Some suppliers were able to charge higher prices than the IOU's for renewable or "green" energy, and most residential customers that switched to direct access did so to increase the amount of renewable energy used to supply their homes. The opt-out feature of CCA eliminates most of the marketing and transactions costs that limited the opportunities in the direct access market for residential and small commercial customers. Through community aggregation, small customers can obtain competitive electricity supplies directly from the wholesale market on a scale that was simply not feasible under direct access rules.

3.1 Lower Electricity Costs

To the extent the County can obtain electricity at a lower cost than charged by SDG&E, the margin can be used to lower rates for CCA customers, contribute to reserve or contingency funds, or augment the County's revenues for provision of public services to its constituents.

A comparison of SDG&E's rates to current market prices for electricity indicates the margin embedded in the generation rates charged by SDG&E. The table below compares the current system average generation rate for SDG&E to the estimated cost of supplying the County at current market prices of electricity.

Cost	Cents Per KWh
SDG&E Avg. Generation Rate	7.1
Estimated Supply Cost	5.6
Gross Margin	1.5

Absent the imposition of a CRS, the County could capture up to 1.6 cents per kWh of margin by procuring electricity at market prices to supply the program. However, AB 117 and ensuing CPUC rules authorize SDG&E to impose surcharges on customers of the CCA that are designed to shield SDG&E and its remaining customers from the costs of losing customers to the CCA. The surcharge represents the difference, on a system average basis, of the average cost of SDG&E's supply portfolio and the market price of electricity. Conceptually, the imposition of the CRS on CCA customers means the County must obtain electricity supplies at below market prices if it is to provide electricity cost savings to its customers during the time period that the CRS applies.

There are essentially two ways the County could obtain below-market electricity prices: 1) the County could negotiate for low cost electric supplies from third party providers, some of whom may be willing to offer discounted prices in order to gain market share and position their firms for sales of other value added services; or 2) the County could utilize its ability to issue low cost municipal bonds to develop or contract for generation resources. Whereas the opportunity for negotiation of low cost supplies would be circumstantial and ultimately may not materialize, the County's financing advantage offers a clear and lasting competitive advantage.8 The County, being a public agency, can finance generation projects at an effective cost of capital that is approximately one half of SDG&E's or the typical merchant generation developer's. As described in greater detail in Section 7.3.2, the municipal financing advantage is particularly well-suited to development of renewable generation projects, with their relatively high capital costs and low operating costs. By financing generation resources (conventional or renewable) or providing capital to prepay for electricity purchases, the County can obtain electricity at below market costs.

Once the CRS terminates at some point in the future, the County will compete against SDG&E's then current supply portfolio, and SDG&E will no longer have the protection afforded by the CRS. By 2013, approximately 40% of the SDG&E supply portfolio will be comprised of power purchase contracts executed after 2005. Therefore, the cost competitiveness of SDG&E's portfolio in the post CRS timeframe will largely depend upon how efficiently SDG&E procures electricity

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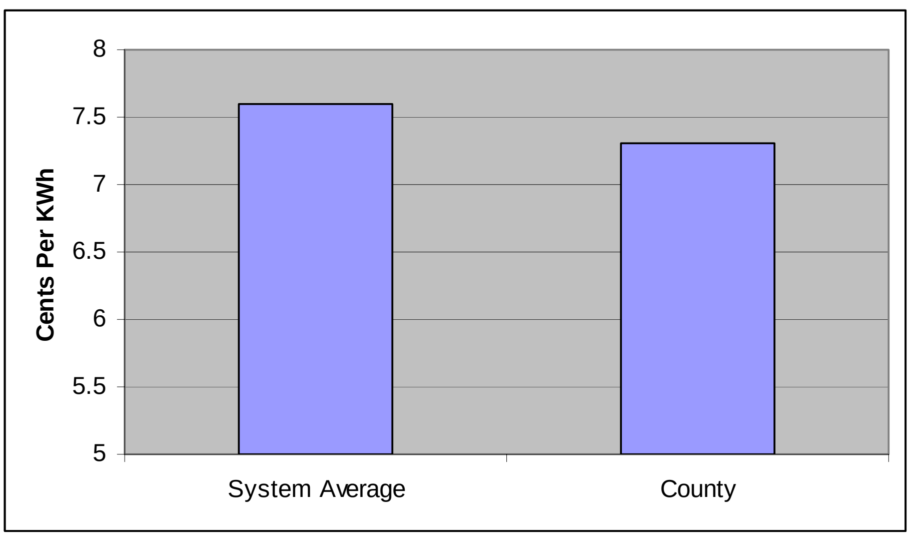
[8] For the financial analysis contained in this feasibility analysis it is assumed that third party electric suppliers would offer electricity at the full market price of electricity and would not offer discounts for the purposes of gaining market share.

supplies during the next several years. The conservative assumption would be that SDG&E will procure electricity at prevailing market prices and that the County will need to bring its financing advantages to bear in order to obtain electricity cost savings in the post CRS period.9

While conceptually, the imposition of the CRS eliminates cost savings opportunities except to the extent the County can procure electricity at below-market prices, in practice the customer mix of the County's program is an important determinant of whether cost savings opportunities exist due to the presence of cross customer subsidies in SDG&E's rate structure. The CRS is calculated as if the County served a mix of customers identical the overall mix of customers on SDG&E's system. The actual customer mix within the County is more heavily weighted towards residential customers, which are subsidized by other customer classes under SDG&E's current generation rate structure. The average generation rates paid to SDG&E by customers within the County are approximately 4% less than the average of all customers within SDG&E's service territory, as shown in the chart below:

Current SDG&E Generation Rates[10]
System Average Vs. San Diego County



[9] As discussed in Section 5.3.1, SDG&E's future generation costs are modeled based on its long-term resource plan and assuming it procures a mix of short and long-term contracts at prevailing market prices. SDG&E may also acquire new generation assets in the future. However, the CCA program would have an inherent cost advantage in developing new generation resources due to its lower cost of capital and not-for-profit status. See discussion in Section 7.3.2.

[10] Includes Electric Energy Commodity Component (EECC), Competition Transition Charge (CTC) and DWR Bond Charge.

The residential rate subsidies are not reflected in the CRS; i.e. the CRS is the same per kWh rate for all customers. Therefore, these subsidies pose an additional cost that must be overcome in the implementation of a CCA program within the County. As discussed in section 6.3, the rate changes proposed by SDG&E in its current Rate Design Window proceeding would eliminate the current subsidies in the generation rate structure, and the adoption of these proposals would improve the economics of a County CCA program.

3.2 Fuel Efficiency and Environmental Benefits

By implementing a CCA program, the County can cause new generation to be developed, either by offering contracts to suppliers for the purchase of energy or by direct involvement in developing new resources. Development of new generation, whether renewable or fossil fueled, will displace production from old, inefficient generation sources, which can significantly reduce environmental impacts of electricity production. According to the CEC, approximately one third of natural gas consumption in California derives from production of electricity. Today's natural gas-fired generation units can operate 30% to 40% more efficiently than the 1960's era generators that are currently online in California. For every kWh produced from a new generation resource, there would be up to 40% less natural gas consumption and even greater reductions in air emissions and greenhouse gases.

A benefit that is particularly important to some communities is the ability to promote use of renewable energy resources and significantly exceed the renewable energy standards applicable to SDG&E. Increased renewable generation would reduce air pollution and emissions of greenhouse gases and reduce dependence on natural gas consumption even further. For the same kWh produced by renewable energy resources, natural gas consumption would drop to zero and, depending on the renewable technology employed, air emissions could also be eliminated.

3.3 Rate Stability

CCA enables the County to lock in electricity prices and provide multi-year rate stability to its customers. Business customers in particular tend to value predictability in their energy costs to aid in business planning. Rate stability can be an attractive feature to help lure new businesses into the community or retain those that may be considering leaving due to high and unstable electricity costs.

CCA allows the community to negotiate for long-term, fixed priced electric supplies from a variety of suppliers. Likewise, increased reliance on renewable energy technologies reduces exposure to the volatile natural gas market, which in turn is a primary driver of electricity price volatility.

Historically, SDG&E's rates have exhibited periods of relative stability punctuated by periods of high rates during times of crisis or the addition of major generation investments. Due to actions taken in response to the energy crisis of 2000-2001, SDG&E's current supply portfolio is much more heavily weighted toward fixed price contracts and renewable energy contracts than in the years immediately preceding the energy crisis, and should be expected to deliver relatively stable (but increasing) costs over the next several years. However, SDG&E is not free to operate in the market in the most efficient manner and must make procurement decisions within the regulatory context in which it operates. To a large extent, SDG&E does not control its own destiny the way an Aggregator can.

The County would possess autonomy over its electricity procurement decisions and the rates it charges to customers, which provides more control over its costs and greater flexibility in its rate structures than SDG&E is allowed under CPUC regulation. More tools are available to the County to control its electric supply costs and rates. For example, publicly-owned (i.e., municipal) utilities commonly create rate stabilization funds using retained margins that enable the utility to weather short-term cost increases without the need to increase rates. In contrast, SDG&E cannot execute supply contracts or build new generation resources without CPUC approval, nor can it establish or modify its rates or reserve accounts without express approval from the CPUC. The regulatory approval process can take many months, and the CPUC may in the end deny the utility's requested authorization. Put simply, the County has more autonomy in its operations than does SDG&E, which enhances the County's ability to provide rate stability to its customers.

New generation is needed to serve California's increasing population and to replace thousands of megawatts of aging power plants that will be retired in the next several years. California is entering a period of major electricity infrastructure investments, and the addition of new utility-owned generation will place upward pressure on SDG&E's rates, contributing to future rate instability. By assuming the responsibility for developing the infrastructure needed to serve the County's constituents, the County can shield its constituents from future rate increases caused by SDG&E generation investments.

3.4 Energy Security

As the majority of new power plants in the United States are fueled by natural gas, the nation is increasingly becoming dependent upon imported natural gas. The flurry of activity related to construction of new liquefied natural gas terminals (LNG) along the California and Baja California coast attests to the increased demand for imported natural gas. Many people are concerned that during the next ten to twenty years the United States will become as dependent on natural gas imports as it currently has become on imported oil. Such dependence raises a host of political, environmental and security issues that potentially threaten the nation's vital interests. By implementing a CCA program that relies more heavily on renewable energy resources, the County can ensure that the electricity consumption of customers participating in the program does not contribute to the problems associated with increased dependence on imported natural gas.

3.5 Customer Choice

CCA provides choice to all electricity customers because all customers have the option of being automatically enrolled in the CCA program or of remaining with SDG&E for provision of generation services. Direct access has been "suspended" by the California legislature, and presently CCA is the only mechanism that allows customers to buy electricity from an entity other than SDG&E. 11 All customers can benefit from opportunities for choice and the disciplinary effects of competition on SDG&E's service even if they do not take advantage of the CCA program.

3.6 Demand Side Energy Efficiency

A CCA program would provide an organizational structure to support administration of energy efficiency programs, and it would also enable seamless integration of energy efficiency into the resource planning process of the County. Energy efficiency or demand side management programs can be tailored to the unique needs of the community and can be integrated with the supply planning

[11] Various proposals have been discussed at the state legislature that would reinstate direct access along the core/non-core structure that was used in the natural gas industry; however in the last legislative session, the Governor vetoed legislation that would have created such a structure.

of the Aggregator, yielding overall lower supply costs. The County's rates can provide the revenue bonding capacity to finance worthy public benefits programs such as installation of rooftop photovoltaic systems, combined heat and power and energy efficiency investments, with debt service provided via monthly customer bills. The County's knowledge of the community can help improve the effectiveness of energy efficiency investments, as the County would be in a better position to identify high potential energy efficiency opportunities in the community.

Local governments should also have strong motivation to deploy effective energy efficiency programs. Investor-owned utilities, such as SDG&E, face a potential conflict of interest in administering energy efficiency programs because the success of their programs reduces the utilities' sales growth and potentially their profitability.12 As an Aggregator, the County would be motivated to reduce overall energy costs, both on the supply and demand side. An integrated approach to supply planning, energy efficiency and demand response, which reflects the specific circumstances of the community, should translate into greater energy savings.

AB 117 requires that a proportional share of energy efficiency funding be spent in the County if it forms a CCA program. Thus, formation of a CCA program would obligate SDG&E to ensure that the County is not under-served by current energy efficiency programs administered by SDG&E or third party administrators. The County could seek authority to replace SDG&E as administrator of energy efficiency programs by submitting a program application to the CPUC. However, current CPUC rules do not grant Aggregators special rights regarding access to public goods funding for purposes of administering energy efficiency programs. This issue may be reevaluated in Phase 2 of the CCA rulemaking (R.03-10-003).

3.7 Self Generation And Wheeling

A CCA program would provide a legal mechanism to transmit excess power from generation located "behind-the-meter" to other loads within the County. For example, excess production from a County cogeneration or solar facility could be used to serve other facilities rather than being sold to SDG&E or lost to

[12] Existing regulatory mechanisms that decouple utility earnings from sales attempt to reduce the disincentives to utility energy efficiency programs.

the system. The CCA program could enable the County to obtain greater value for its distributed generation facilities.[13]

3.8 Regional Economic Competitiveness

The County could use its ratemaking authority to establish economic development and business attraction rates to help lure desirable businesses and jobs to the community with the benefit of lower rates. Competitive electric rates can also be a factor in retaining businesses that might otherwise leave the community, seeking locations with lower costs of doing business. A CCA program that provides low and stable rates can be an important factor in maintaining regional economic competitiveness.

Reliability of the electric system is fundamental to the region's economic competitiveness. To the extent the County initiates development of local generation resources to serve the CCA program, the reliability of the local area would be enhanced.

3.9 Creation of Strategic/Asset Value

Formation of a CCA program creates strategic value arising from the creation of assets, infrastructure and annual cash flows. The County would be developing expertise in energy matters, building infrastructure, and positioning itself for an expanded role in the provision of energy services if future circumstances warrant such an expanded role.

3.10 Opportunities For Innovation

A CCA program presents opportunities for the County to provide innovative energy services to customers. The County could develop programs that respond to the local concerns, needs, and values of their community members. One example would be formation of "green pricing" programs that provide customers the option of choosing to use more renewable energy. Customers that value renewable energy would be able to voluntarily pay for any additional costs of increasing the renewable energy mix, reducing the costs to be paid by more price sensitive customers. Other innovative services could include special rates

[13] Whether greater value can be achieved in practice would depend upon whether an existing contract is in place governing the sale of excess power from the facility and upon the pricing terms and conditions of the contract.

for population subgroups (e.g., low income, government facilities, enterprise zones, etc.), program-financed distributed generation, or a host of other value-added services.

4 RISK ASSESSMENT

The risks of forming a CCA program evolve as the County begins its implementation planning process and then progresses to startup of program operations. The County's risk exposure also depends greatly upon the implementation approach utilized by the County, as previously discussed in section 2.5. Therefore, the risks will become more clear as the County engages in its implementation planning.

The major risk associated with forming a CCA program is the possibility that the rates of the program exceed the comparable rates charged by SDG&E, causing customers to become dissatisfied with the program or attempt to return to SDG&E service. When considering risks, it is important to distinguish between risks borne by the CCA entity and risks borne by the customers that participate in the program. Customer attrition could leave the CCA program with long-term obligations and reduced revenues. The County's ratemaking authority and ability to raise rates if necessary would protect the County from the financial impacts of unanticipated program cost increases. The County could impose an exit fee to recover the cost of long-term obligations that may be stranded by customers leaving the program. However, these costs would be paid by the very constituents whose interests the County represents. For these reasons, the risks of the County forming a CCA program generally remain with the customers that elect to participate in the program. Similarly, customers of SDG&E ultimately bear the risks of SDG&E's energy procurement practices, but SDG&E is not accountable to its ratepayers to the same degree as is the County.

Pending the development of switching protocols in Phase 2 of the CCA rulemaking, the County could ultimately terminate the program, if necessary, and return customers to SDG&E service. The program would likely set aside financial reserves to cover any reentry fees that may be applicable in the case of program termination.

4.1 Implementation Plan Stage Risks

At the Implementation Plan stage, the County will have evaluated the feasibility of becoming an Aggregator and assessed the expected costs, benefits, and risks of implementing a CCA program. To progress to the next stage, the County will need to commit additional funds for the development of an Implementation Plan. The primary risk at the Implementation Plan stage is political, especially if SDG&E directly or indirectly opposes the CCA program. Whereas each of the local utilities has publicly supported CCA, there are always caveats that in practice might cause them to oppose a specific implementation effort as it progresses towards an Implementation Plan.

Typical utility responses to local government energy initiatives are to urge the local government's leaders to slow down so as not to rush into something they do not fully understand. The utility may criticize the feasibility study's assumptions and methodology and suggest that becoming an Aggregator entails great risk with little or no commensurate benefits. Furthermore, SDG&E may formally oppose elements of the Implementation Plan at the CPUC. For example, each of the utilities has voiced opposition to allowing Aggregators to phase-in operations over a multi-year period, and phase-in proposals contained in an Implementation Plan may be protested. In the extreme case, the utility might sponsor community organizations to oppose the program, as has been done by both SDG&E and SCE in their efforts to oppose municipalities from forming distribution utilities within their historical service territories. While such strong opposition to a potential CCA program is unlikely, the County should be realistic and not expect complete support from the utility for its efforts.

Once a commitment to developing the Implementation Plan is made a fairly intensive effort will be required to decide the particulars of the CCA program. Choices must be made regarding program management and organizational structure, suppliers and resources, rates and customer protections, terms and conditions of service, financing and staffing.

At this stage, there is also the regulatory risk that the CPUC will adopt or modify implementation rules to the detriment of the CCA program or in a way that requires modifications to the Implementation Plan. The development of the Implementation Plan can be done in parallel with the CPUC process. The Implementation Plan should be filed with the CPUC after the CPUC issues its final (Phase 2) decision in order to avoid the potential expense of re-filing the plan. However, delays in the CPUC process can derail the implementation effort if the process is dragged out indefinitely. Elected leaders that were early supporters of implementing a CCA program may finish their terms before the program can be implemented, and newly elected leaders may desire to reconsider the decision to proceed with CCA implementation. Turnover of key staff could also jeopardize timely program implementation.

4.2 Operational Planning Stage Risks

Following development and acceptance of the Implementation Plan, the County will begin making commitments to be able to commence operations. Depending on how the County elects to structure its program, additional funds will be needed to finance the start-up activities. These may include the following:

- Conduct recruiting and staffing
- Develop informational and program marketing materials
- Establish call center for customer inquiries
- Contact key customers to explain program, obtain commitment, and obtain authorization to release customer information to the CCA program
- Prepare short and long-term load forecast
- Develop capability or negotiate contracts for operational services
  - Electronic data interchange with utility: accept meter and usage data, send billing data, accept payment and remittance information, exchange customer switching information
  - Customer bill calculations
  - Scheduling coordinator services
  - Application of statistical load profiles and submittal of hourly usage data for grid operator settlements
  - Resource planning, portfolio and risk management
  - Ratemaking
  - Load forecasting
  - Wholesale settlements
  - Credit
  - Information Technology
- Execute contracts for electric supply
- Identify generation projects and negotiate participation, if applicable
- Obtain financing for program capital requirements
- Execute service agreement with utility
- Complete utility technical testing
- Establish account with utility
- Send customer notices to eligible and ineligible (e.g., direct access) customers
- Process customer opt-out requests
- Submit notification certification to CPUC

These commitments should not be made until the CPUC has finalized the rules for CCA implementation, which is expected to take place in the Fall of 2005. At that point, the regulatory risk diminishes significantly, and the County has a great deal more certainty regarding the detailed processes that will be required for operating a CCA program.

4.3 Operations Stage Risks

The primary risks inherent in the CCA operations are that unanticipated events cause the County's costs to increase or the rates of SDG&E to decrease. In these cases the rates charged by the County could exceed those of SDG&E, and customers may become dissatisfied with the program. To the extent customers are not precluded from leaving the program, the County could face stranded costs and higher rates prompting additional customers to leave the program. Appropriate program rules that limit customer switching or that impose exit fees to compensate remaining program customers for commitments made on behalf of the departing customers will mitigate the risk of losing customers, from the perspective of the CCA operator. However, the program's customers would then bear the risk of potentially paying higher rates than those offered by SDG&E (or other competitors). These risks highlight the importance of clear disclosures in the customer notification process so that potential customers are clearly informed of their rights and obligations prior to taking service in the program. Potential customers should be informed prior to the customer enrollment process that ratepayer savings are expected but cannot be guaranteed.14

The predominant cost of service variables and risks that might impact the County's operations cost are as follows:

- The cost responsibility surcharge will vary year-to-year. The CRS is inversely related to the prevailing market price of electricity such that if market prices fall, the CRS will increase. To the extent the CRS increases and the County has locked in electricity prices through long-term electricity or fuel contracts, the CCA customers' total rates will increase. The CRS could also increase if the CPUC allows SDG&E to include new power purchase contracts or resources in the CRS, and the costs are above prevailing market prices.

[14] This discussion assumes an implementation model where the program's energy supplier is not offering a guaranteed savings pricing structure.

- The County could unfavorably hedge its exposure to electricity and/or natural gas price volatility, and adverse price movements could cause rate increases for its customers. Similarly, the County could over-rely on long-term contracts with fixed prices and find itself holding a high cost portfolio if market prices subsequently fall.

- The County could fail to properly secure its customer base, making debt financing via the capital markets impossible to obtain and exposing the County to stranded costs if customers opt-out of the CCA program. Even with appropriate switching rules, large customers may go out of business or leave the area and leave behind costs that must be paid by remaining program customers.

- The County's energy suppliers could default on supply contracts (credit risk) at times when energy spot markets are high, forcing the County to purchase energy at excessively high prices. Customers could fail to pay the County's charges, and the County's credit policies and customer deposits may be insufficient to recover the uncollectible bills .

- SDG&E could make changes to its rate designs that reduce the cost of generation services and increase the costs of delivery services or that shifts costs among customer classes in a manner that disadvantages the customer mix served by the County.

- Other regulatory risks associated with changes in the rules and tariffs administered by the CPUC or in the wholesale markets regulated by the Federal Energy Regulatory Commission (FERC) could increase the County's cost of providing service. For example, the institution of a requirement to use geographic-specific load profiles for electricity procurement could advantage coastal communities to the detriment of those located in hotter, inland climates.

- The availability and cost of firming services for intermittent renewable resources, such as wind energy, in the program's supply portfolio as well as the adequacy of the transmission system to support integration of new renewable energy.[15]

[15] The specific supply sources utilized by the program, including issues of deliverability, would be addressed in the Implementation Plan study. Firming services could be provided from dispatchable natural gas-fired resources or, ideally, hydro-electric resources.

Each of these risks can be mitigated, although not altogether eliminated. The County can structure its program in such a way that it would be exposed to very little risk. Electricity supply contracts can be structured to transfer many of the risks to the program's suppliers. The following table describes basic risk management techniques for each of the primary risks associated with operating a CCA program.

Risk	Mitigation
Cost Responsibility Surcharge Volatility	Utilizing shorter duration supply contracts to a greater extent than would otherwise be indicated would offset the CRS risk. If market prices decrease, the County's supply portfolio costs will also decrease, offsetting the increase in the customer's CRS payments to SDG&E.
Commodity Price Volatility	Diversify supply portfolio with contracts of various terms and with multiple suppliers, renewable energy, and conventional generation. Layoff commodity price risks to energy suppliers through fixed priced contracts or guaranteed discount pricing structures
Customer Attrition	Establish exit fees following free opt-out period. Negotiate term contracts with large customers.
Credit Risk	Periodic credit and exposure monitoring; supplier diversity; collateral and surety instruments. Require deposits from high risk customers and return to utility for failure to pay bills.
Utility Rate Changes and Other Regulatory Risks	Participate in CPUC process to prevent shifting of costs to program customers

4.3.1 Operations Risk Discussion

Ultimately, the major operational risks are under the control of the program's management. Disciplined, professional management is key to managing risks inherent in offering retail electric services. The County will be able to contract for services from a variety of large, experienced energy suppliers that have operational capabilities equal to or better than those of SDG&E. It should be noted that municipal utilities have been successfully managing commodity, credit, and operational risks for many decades, even during times of high commodity prices and supply shortages. The County could contract with municipal utilities or private energy companies to provide services to the CCA program.

The experiences of SCE, PG&E and SDG&E during the energy crisis of 2000-2001 illustrate what can happen when risks are not properly managed. The investor owned utilities' exposure to commodity price risks during the energy crisis and the ensuing financial devastation experienced by SCE and PG&E stemmed from an artificial constraint imposed by the CPUC on their hedging abilities, coupled with an inability to increase retail rates due the legislated rate freeze. The CPUC's so-called buy/sell requirement forced the utilities to buy 100% of their energy from the state sanctioned (now defunct) California Power Exchange daily market auction and sell 100% of their generation resources into that market. Because the utilities had divested nearly all of their natural gas fired generation resources, they were each heavily short on resources and overly reliant on the spot market. When spot market prices spiked for an extended period of time, the cash drain necessitated the State of California (Department of Water Resources) to take over electricity procurement responsibilities from the utilities. Customers of SDG&E were not protected by the rate freeze and suffered from excessive rates as SDG&E was able to pass through its costs of procuring electricity from the spot markets.

The County will not be subject to these types of constraints on its procurement practices. Being a municipality, it will exercise its own authority over its resource planning and ratemaking decisions. A professionally managed electricity procurement program, following sound risk management practices, would not expose itself to the risks that the investor owned utilities faced during the energy crisis.

4.4 Regulatory Risk Discussion

Regulatory risks refer to the potential that decisions by regulators could cause cost increases for the CCA program. The County can participate in regulatory proceedings at the CPUC or FERC to try to influence the regulatory process to protect its interests and those of its customers. Typically, associations are formed among entities with common interests to participate on their behalf in the regulatory process to effectuate maximum influence on regulators. The amount of influence wielded in the regulatory process depends on the resources the association can devote to participation and the political influence of the associations members. Thus, to some extent the degree by which regulatory risk can be managed depends upon the prevalence of CCA throughout the state. If CCA becomes a widespread phenomenon, with many communities being directly impacted by CPUC decisions, the CPUC is less likely to make decisions that impose additional costs on Aggregators than if only one or two communities would be impacted.

4.5 Risk Mitigation Through Physical and Financial Reserves

Physical and financial reserves are important components of a CCA program that reduce program risk. Industry rules dictate certain reserve requirements for all market participants to protect the integrity of the system. These rules ensure no degradation of reliability would result if the County were to implement a CCA program.

4.5.1 Physical Reserves

The program will be required to comply with industry rules governing the provision of physical reserves to ensure reliable operation of the electric grid. The California Independent System Operator (CAISO) requires load-serving entities to maintain operating reserves (6% to 8% of load) and regulating reserve (2.5% to 5%) that can be quickly called upon in the event that scheduled resources experience outages or electricity consumption unexpectedly increases. Load serving entities can arrange for their own reserves, or the CAISO will charge the load serving entity for the costs of reserves procured on its behalf. The costs of these reserves are included as an expense item in the pro forma.

On a longer-term basis, the CPUC requires load-serving entities to arrange for a 15% planning reserve margin, approximately one year in advance. The planning reserve requirement was instituted in 2004 and is intended to both ensure the existence of adequate generation capacity as well as to reduce the ability of power suppliers to charge high electricity prices that can occur when capacity is scarce. The costs of planning reserves are included as an expense item in the pro forma.

4.5.2 Financial Reserves

The program will maintain financial reserves in the form of rate stabilization funds or other reserve funds that would be required by the banks to support debt financing of program assets. Rate stabilization funds are accrued through rates and maintained at the discretion of program management and the program's governing board. They are used to cushion short-term cost increases as well as to accrue cash for future capital expenditures. To the extent that debt financing is utilized to fund capital expenditures, banks will require minimum debt service reserves equal to approximately 10% of the amount borrowed, and will also impose minimum debt service ratios to ensure adequate debt service coverage. These financial reserves are included in program rates in the base case analysis, but these funds are an asset of the program that will ultimately be accessible for future rate reductions or other program purposes.

4.6 Risk Mitigation Through Phased Implementation

The County could implement a CCA program in phases to limit any risks associated with program startup and the transition of customers from SDG&E to service by the program. An example could be to initially offer the program to non-residential customers for a pilot phase such as six months or one year and then to open the program to all customers after the pilot phase is completed. By starting with non-residential customers, the number of transactions (account transfers, coordination with SDG&E's monthly billing process, etc.) that must be completed would be a small fraction of what would be required to serve the entire community at one time. Another benefit of this type of phasing arises because non-residential customers are higher margin customers so the initial phase-in period would provide greater margins for the program to help cover program startup costs.

In its final Decision in Phase 1 of the CCA Rulemaking, the CPUC ruled it will not determine which customers the CCA should serve and will leave the matter to the CCA.16 However, the County must comply with the legal requirements of

[16] See D.04-12-046, Conclusion of Law No. 38.

AB 117 that requires equitable treatment of all customer classes and the offering of service to all residential customers. The Implementation Plan should describe the phasing approach, if any, that the County intends to utilize and how that approach complies with the law. There may also be incremental costs asserted by SDG&E to accommodate the County's specific phasing proposal, which the County would responsible for paying.

5 FEASIBILITY ANALYSIS

5.1 Study Approach

In preparing the financial evaluation for a CCA program, NCI did a thorough analysis of: (1) SDG&E's forecasted rates (including cost responsibility surcharges); (2) CCA energy or commodity costs (including generation ownership, power purchase contracts, renewable energy contracts and spot-market purchases; (3) CAISO charges; (4) operations and scheduling costs; (5) financing costs; and (6) revenue offsets and available financial incentives. Each of these items was factored into the pro forma analysis. The CCA program's capital costs are amortized over a 30-year period and financed at a rate of 5.5%. The interest and amortization are included in the annual costs of the program. The financial pro forma analysis compares the total costs of operating the CCA program with the total costs of continuing to take retail utility service from SDG&E.

A financial analysis was performed in order to develop financial pro forma, which are then structured as consolidated statements of income for the CCA program. The consolidated statements based on the financial pro forma are located in Appendix E. As noted above, savings or potential income is the margin between current retail power costs, as provided by SDG&E, and the County's projected cost to provide the power. NCI began its evaluation with a planning horizon beginning in the current year (2005) and then projected costs 20-years forward to 2024.

SDG&E provides services at regulated cost-based rates. Hence, SDG&E's rates are directly tied to a demonstrated "revenue requirement", which is the total revenues the utility is authorized to recover through rates. The revenue requirement includes the utility's expenses, return or profit, and taxes paid by the utility. The financial analysis provided herein compares SDG&E's revenue requirement at current and projected rates with the revenue requirement of the CCA program to determine potential savings or income. Pro forma summary tables compare each supply portfolio based on their relative ability to produce operational cost savings or benefits.

In a CCA program, utility service is limited to the electric energy commodity only. SDG&E would continue to provide electricity delivery over its existing distribution system and provide end-consumer metering, billing, collection and all traditional retail customer services (i.e., call centers, outage restoration, extension of new service).[17] Accordingly, to evaluate the potential benefits for CCA, only costs associated with wholesale electric commodity procurement and related business expenses are considered.

5.2 Customer Base

The potential customer base for the CCA program is all of the electric customers in the unincorporated areas of the County. However, customers have the option to opt-out of the CCA program and continue to receive their electric service from SDG&E. Some customers may choose to not participate in the program, or opt-out during the 60-day opt-out period, and some direct access customers may be contractually prevented from initially joining the program until their direct access contracts expire. The prevalence of customer opt-outs will depend on a number of factors, not the least of which is how the County's electric rates compare to those of SDG&E. Other factors that will influence customers' opt-out decisions include whether the County provides non-price features important to customers such as increased renewable energy purchases or expanded energy efficiency programs; customer loyalty or enmity to SDG&E; and other customer perceptions. Many of these factors are directly dependent on the details of the County's Implementation plan, and the impacts cannot be reasonably estimated prior to completion of the County's implementation planning process. For the purposes of this feasibility analysis, the report presents the potential benefits from CCA, assuming 100 percent customer participation, except for existing direct access customers. Within a reasonable range of assumed opt-out percentages, the study results can be adjusted proportionately.

5.3 Key Assumptions

As described in Section 2.2, the CPUC is in the process of finalizing the rules for CCA implementation. NCI developed several framework assumptions for this feasibility analysis and also adopted a set of detailed assumptions for various unknown costs and implementation rules. This section describes the high level assumptions that provide the framework for the analysis. The detailed assumptions are listed in Appendix B.

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[17] The CCA operator will need to provide customer and account services for the services it provides. It will also need to exchange billing and payment data with SDG&E to coordinate with SDG&E's monthly billing process. These activities are discussed in Appendix D.

1. CCA Rulemaking is completed by the third quarter of 2005, and CCA operations can begin in January 2006

2. Charges authorized by the CPUC for Aggregators and CCA customers are similar to those charged to direct access customers (transaction and implementation fees)

3. Aggregators must maintain adequate capacity reserves to maintain reliability standards and will follow standard industry risk management practices. Aggregators will be held to the same capacity reserve standard as SDG&E.

4. Aggregators will match or exceed the renewable energy content of SDG&E's portfolio and are eligible for the existing CEC subsidies provided for renewable energy procurement up to the minimum renewable portfolio standard (i.e., subsidies are available for the first 20% of renewable energy)

5. Market prices for renewable energy will reflect the developer's costs, including the effects of available subsidies

6. Aggregators can finance generation projects

7. Aggregators can obtain electricity from the wholesale market on comparable terms with the IOUs

8. The CPUC does not allow IOUs to negotiate special rates or contracts to retain customers

9. CCA operations can be outsourced to third parties

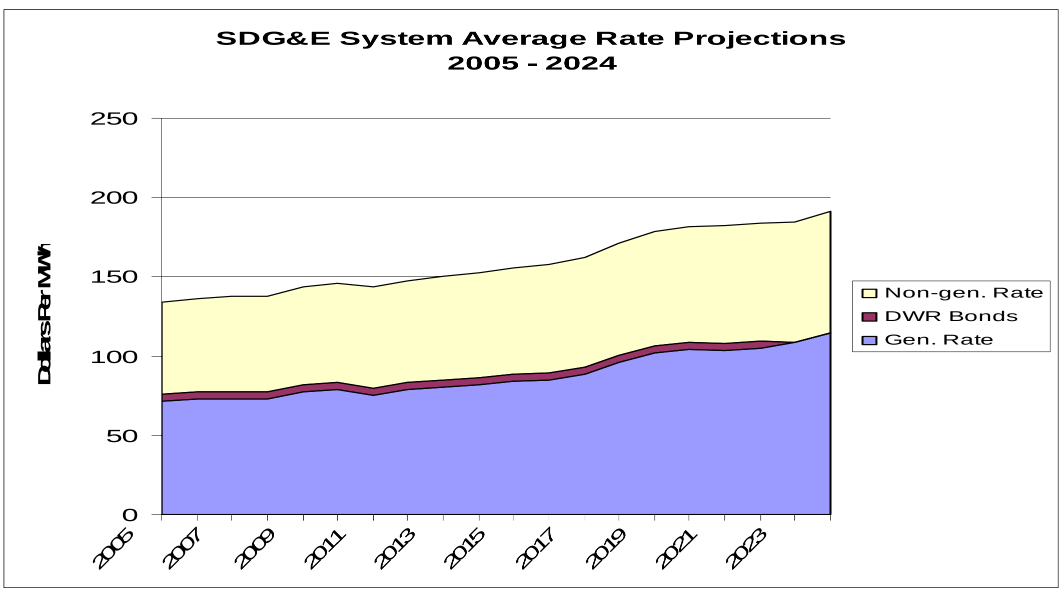
10. Reinstatement of direct access does not preempt CCA rights and customer relationships

5.3.1 Utility Rate Benchmarks

Estimates of CCA cost savings potential are assessed by comparing CCA costs to the rates that would otherwise be charged by SDG&E. The base case utilizes SDG&E's current rate designs and adjusts current rates for expected changes in SDG&E's generation costs in order to project SDG&E rates for the 20-year study period. NCI prepared a sensitivity case for the rate design changes proposed by

SDG&E in its ongoing Rate Design Window Case, which transfers certain costs out of generation rates into non-bypassable delivery charges.[18] The effect is to increase the generation rates of residential customers and reduce the generation rates of commercial and industrial customers. These proposals, if adopted by the CPUC, would improve the economics of a County CCA program because of the relatively high mix of residential customers within the County's potential service area. The sensitivity results are described in Section 6.3.

SDG&E's rates derive from its costs or "revenue requirement", and NCI modeled SDG&E's annual generation revenue requirements for the 2005 to 2024 study period. The resulting rate projection shows generation rates increasing at a modest average rate of 2.4% per year due to offsetting influences on SDG&E's generation costs. The projected annual rate increase of 2.4% is in line with historical trends.[19] Generation cost increases are somewhat offset by the expiration of high cost DWR contracts in the 2004 to 2012 period, and the net result is a moderately increasing rate forecast. Once the DWR contracts expire in 2012, SDG&E's generation costs are expected to show annual increases consistent with general levels of inflation and gas price escalation.

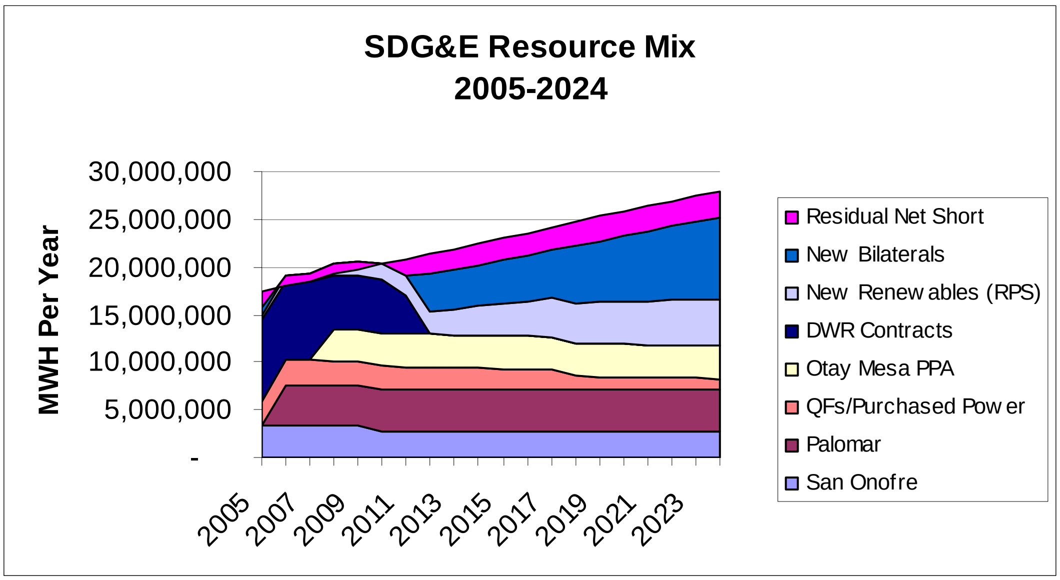


SDG&E's generation revenue requirements are modeled for each resource in SDG&E's generation portfolio, including the DWR contracts the CPUC allocated to SDG&E in Decision No. 02-09-053. As production from existing resources or

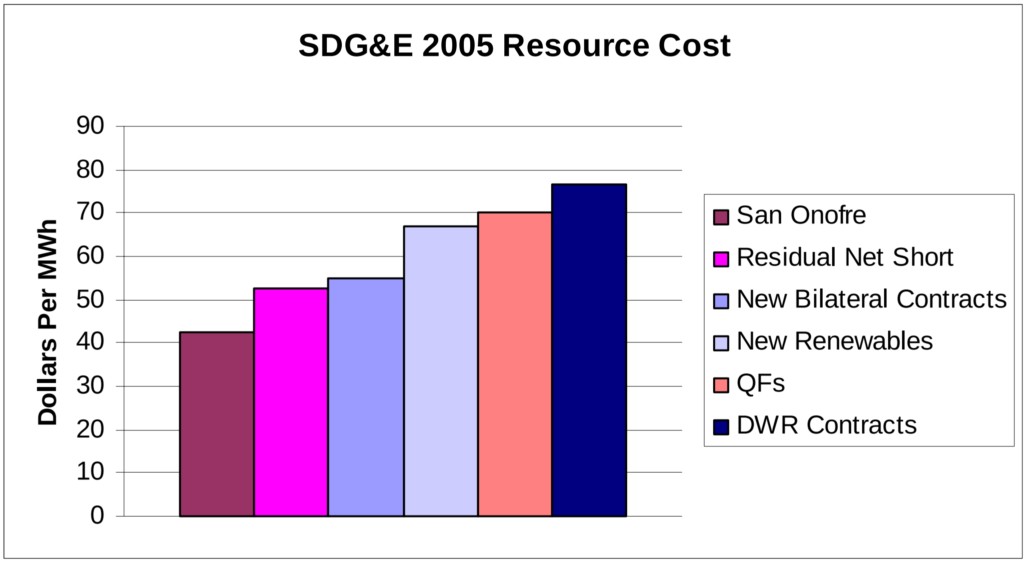
[18] Application Number A.05-02-019, filed on February 19, 2005.

[19] Depending upon the specific timeframe selected for comparison, during the past twenty-five years, SDG&E rates have increased by an average annual rate of between 1% and 4%.

supply contracts decline over time, they are replaced by new power purchase contracts at prevailing market prices. Short-term "spot market" purchases are maintained at 15% of the total portfolio. New renewable contracts are added to the resource mix to meet the applicable Renewable Portfolio Standards requirements, and planning reserve requirements of 15% are enforced in the rate projections.



The revenue requirement for each resource type was modeled based on data provided by SDG&E in its 2003 Cost of Service Proceeding and FERC Form 1 filings. The current costs are shown below. Costs were projected forward for the study period by calculating annual depreciation, operations and maintenance expenses, taxes, and authorized return on rate base for each resource.



5.3.2 Cost Responsibility Surcharges

The single greatest obstacle to achieving significant cost savings through CCA in the next several years is SDG&E's imposition of cost responsibility surcharges on CCA customers, which are designed to shield SDG&E from any financial losses or cost increases that might result from customers switching to service by the Aggregator. NCI modeled expected cost responsibility surcharges using the methodology adopted in the CCA Phase 1 Decision (D.04-12-046). According to this methodology, the above market portion of SDG&E's generation portfolio, including SDG&E contracts and resources and the DWR contracts, are included in the CRS. An additional element of the CRS is the DWR Bond Charge, which was established to recover past power purchase expensed incurred by the DWR during the energy crisis. The DWR Bond Charge is reasonably certain and predictable, while the uneconomic portfolio costs are less easily predicted because they directly depend on future electricity market prices and SDG&E's future generation costs.

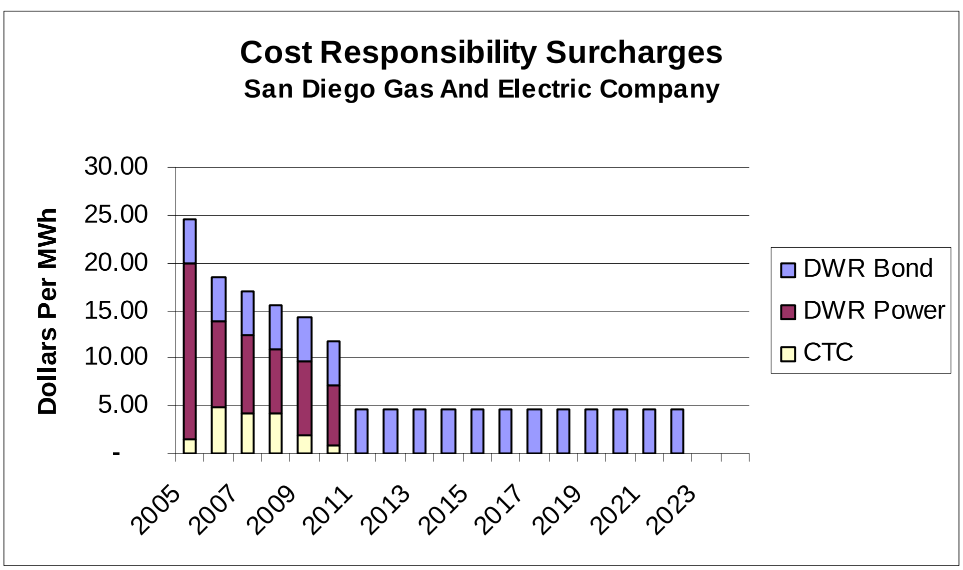
In D.04-12-046, the CPUC adopted an interim CRS of 2.0 cents per kWh. [20] The CPUC established the interim CRS for an 18-month period and ordered SDG&E to calculate an updated CRS based on current forecast data. The adopted CRS methodology causes the CRS to be inversely related to electricity market prices: *i.e.*, as market prices increase the CRS declines and vice versa. Because current market price projections are higher than those used by the CPUC to establish the

[20] The 2.0 cents per kWh interim CRS is in addition to the DWR Bond Charge.

interim CRS estimate, the updated CRS is expected to be lower than the interim amount. NCI used the interim CRS for 2005 and assumed that it would be updated by SDG&E prior to 2006.

The CRS cost estimates used in this analysis are consistent with the electricity cost projections underlying the County's modeled supply portfolio. The electricity market prices are somewhat higher than the estimates used by the CPUC to develop the 2.0 cents per kWh interim CRS. As a result, in NCI's analysis the CRS is projected to decline sharply from 2005 to 2006 as the interim number is replaced with the updated cost figures. If future power prices turn out lower than those used for the base case analysis, the CRS would be higher than the forecasts used in this analysis. However, the cost of procuring power for the CCA program would be lower than the costs used in the analysis. These two impacts tend to offset each other. Therefore, the magnitude of the CRS should not be looked at in isolation, but should be assessed in context with the market price assumptions used in the overall feasibility assessment. The net effect of higher or lower power prices on the overall cost of service for the CCA program can be seen in the sensitivity analysis results presented in Section 6.3.

The following chart shows the components of the CRS for SDG&E over the study period under the base case scenario.



With the exception of the DWR bond charge, the CRS is expected to become zero by 2012, as DWR contracts expire and market prices trend upwards.

For purposes of the base case analysis, NCI has calculated the CRS based on the methodology adopted by the CPUC in its Phase 1 Decision and with the assumption that the CPUC will revise the interim CRS based on more recent market data, as ordered in that decision. The base case estimates are consistent with the Phase 1 Order. However, there is the possibility that the CPUC will not update the interim CRS before the 18-month interim period expires, which would be July 2006. That eventuality would effectively delay the earliest feasible start date for program implementation to the second half of 2006, because application of the interim CRS would cause program rates to exceed the rates charged by SDG&E. The effects of a higher CRS are shown in the sensitivity case described in Section 6.3, where NCI modeled the financial impact of increasing the CRS by 50% from the base case estimates.

Once the County files its CCA Implementation Plan, the future procurement activities of SDG&E will not impact the CRS paid by the County's customers because the set of SDG&E procurement obligations applicable to the CCA program will locked-in as of that date. The County may be able to provide notice to SDG&E in advance of the Implementation Plan, utilizing the "Open Season" concept currently being discussed in Phase 2 of the CCA Rulemaking, which would insulate the CCA program from any additional SDG&E procurement costs. It should be noted that SDG&E's long-term procurement activities will not necessarily translate into a higher CRS; their impact on the CRS depends on the prices that SDG&E pays for supply as compared to the market. If SDG&E obtains resources at market prices, there would be no impact on the CRS. Thus, the net effect of SDG&E's long-term procurement solicitation could be to increase the CRS, decrease the CRS, or be neutral to the CRS.[21] The County should signal its intent to form a CCA program at the earliest possible date so that SDG&E can refine its CCA activity estimates and adjust its procurement practices going forward.

5.3.3 Renewable Energy Subsidies

A variety of tax incentives, credits and publicly funded subsidies exist for renewable energy development, which reduce the effective cost of increasing the renewable energy content of the program's supply portfolio. These include the following subsidies:

[21] The base case analysis assumes SDG&E procures resources at market, and therefore new SDG&E procurement does not impact the CRS.

– Production Tax Credits
– Renewable Energy Production Incentives
– Supplemental Energy Payments (Public Goods Funds)

Some of the incentives, such as the production tax credit for renewable energy production, are short-term and must be reauthorized by Congress on an annual basis. Others, such as the public goods funding for renewable energy development administered by the California Energy Commission ("Supplemental Energy Payments"), are more long lived, but are contingent on the sufficiency of the public goods fund collected through utility rates. The economic analysis conducted for the County includes the effect of Supplemental Energy Payments available to producers of renewable energy as described in more detail below. The other potential subsidies are not included in the analysis although they may ultimately be available to further reduce the program's cost of service.

Subsidies are included for renewable energy purchases from the market, to the extent such purchases are needed to supplement production from the County's resources. The renewable energy costs for purchases up to the minimum renewable portfolio standard are offset by Supplemental Energy Payments, while the incremental renewable energy above and beyond the minimum requirement is assumed to receive no subsidy. Thus, the costs of renewable energy utilization above the first 20% would be paid entirely by customers of the CCA.

No Supplemental Energy Payments are assumed to be available to offset costs of the County's renewable resources that it owns or otherwise finances. The reason for this assumption is that the process for determining Supplemental Energy Payments was premised on the utilities conducting competitive solicitations for long-term supply contracts with producers of renewable energy. Funds are made available to winning bidders to cover the excess of their costs above a market benchmark, determined by the CPUC. The CPUC has so far been focused on how the utilities are to meet the Renewable Portfolio Standards, and the rules and protocols for making Supplemental Energy Payments available to Community Choice Aggregators have not yet been established.

It is unclear at this time how the process developed for the utilities would apply to an Aggregator that develops its own renewable resources rather than procures renewable energy through long-term, competitively solicited contracts. Financing structures that entail prepayment for energy through long-term power purchase contracts with a renewable energy producer should theoretically allow the County to receive the benefits of its financing advantages and also qualify the producer for Supplemental Energy Payments. However, as stated above, the rules have not been established, and the conservative assumption that no such subsidy would be available was used in this analysis.

5.4 Financial Analysis Structure

CCA customer population electric loads are applied to SDG&E's current and projected generation rates to yield its revenue requirement recovered from the customers in the potential CCA area. CCA operating expenses are projected and subtracted from SDG&E's revenue requirement to yield the projected financial benefit. Elements contained in the analysis are summarized below and details of the inputs, assumptions and sources are provided in Appendix B:

Utility Forecast Generation Rates

- Utility Retained Generation
- Qualifying Facility Generation
- Bilateral Power Purchase Contracts
- New Renewable Energy Purchases
- CAISO charges
- Residual Spot Market Purchases or Sales

CCA Energy Cost (Commodity Costs)

- Spot Market Purchases
- Power Purchase Contracts
- Renewable Energy Contracts
- Generation Ownership

California Independent System Operator Charges

- Ancillary Services/Reserves
- Grid Management Charges
- Deviation Charges

Operation and Scheduling Costs

- Electricity Procurement
- Risk and Credit Management[22]

[22] The costs of uncollectible customer accounts are not explicitly included in the pro forma, under the premise that the Aggregator would require customer deposits from customers that pose likely credit

- Load Forecasting
- Scheduling and Settlements
- Rates
- Account Services
- Administration

Non-Bypassable Charges/Cost Responsibility Surcharge

- Uneconomic Utility Retained Generation and Power Contracts
- DWR Power Purchase Contracts
- DWR Bond Charges - Financing Past Purchases

5.5 Load Analysis

Detailed definition of community electric power needs is required to assess the economic viability of the CCA providing electric energy as an alternative to the community's existing supplier, SDG&E. Community electric demand and energy consumption, generally referred to as electric load, has been analyzed and described in charts and graphs located in Appendix G. NCI performed load analysis and constructed a load forecast beginning with and based upon data provided by SDG&E in response to the Community's formal request (see Appendix C for sample data request letter). The Community's annual hourly load shape was developed, and a determination made regarding associated energy supply requirements. The time-of-use supply requirements serve to define the types of resources necessary to supply electric energy to the CCA.

5.5.1 Load Forecast Methodology

Community electric load data provided by SDG&E was 12-month, year-to-date energy consumption by rate class and zip code as of October 2004. SDG&E provided data for 4 rate classes (Residential, Commercial, Agricultural, Lighting). [23]

The load information was treated as prototypical for 2004 energy consumption. SDG&E's published static load profiles were employed to allocate monthly

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risks, similar to the accepted utility practice. Because under current rules the Aggregator cannot cause service to be shut-off to the customers for failure to pay its portion of the bill whereas the utility can, it is important that the Aggregator have the ability to screen customers prior to automatic enrollment for administration of its credit policies and that the Aggregator has the right to return the customer to the utility for failure to pays its charges. This issue should be addressed in Phase 2 of R.03-10-003.

[23] The data exclude loads of direct access customers.

energy (kWh) into each hour of the month and then to each of the 8,760 hours within a year.

A twenty-year electric load forecast was performed forecasting electric demand energy requirements for years 2005 through 2024. Electric energy requirements and customer populations were escalated based upon sector specific growth planning statistics provided by the County; if none was provided SDG&E system-wide growth rates were applied.

The number of customer accounts and annual energy sales for the initial year (2006) of the program are shown below.

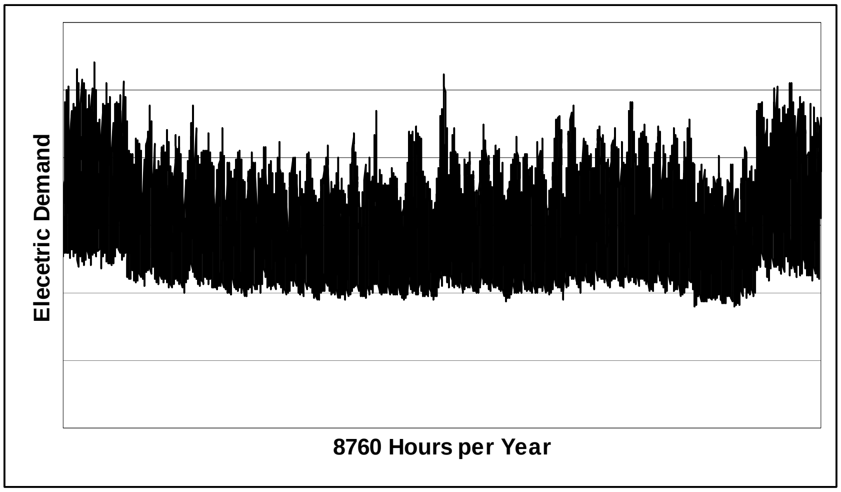
	2004 *		2005 *		2006 *	
	Accounts	MWh	Accounts	MWh	Accounts	MWh
Residential	228,566	1,329,807	236,950	1,378,584	244,920	1,424,953
Small Commercial	9,089	162,496	9,422	168,456	9,739	174,123
Medium Commercial	1,457	679,628	1,510	704,557	1,561	728,255
Large Commercial/Industrial	35	97,621	36	101,202	38	104,606
Agricultural	6,938	163,251	7,193	169,239	7,435	174,931
Street Lighting/Traffic Control	601	9,901	624	10,264	645	10,609
Total	246,686	2,442,704	255,735	2,532,302	264,337	2,617,477

* Data Provided by Distribution Utility (SDG&E) Was Energy Usage for 2-Months of 2003 and 10-Months of Energy Used for 2004
Data Were Treated as 2004 Data and Escalated Annually By the Following Growth Rates:

Residential	variable	Declines from 4% TO 2% by 2012; 2% flat from 2013-2024
Commercial	variable	Consistent With CEC Energy and Regional Demographic Forecasts
Street Lighting and Traffic Control	variable	

5.5.2 Community Energy Load Shape

The community composite annual energy load shape (average kW per hour) was developed by combining average loads in each hour from each of the Customer Sector static load profiles identified above. A prototypical annual load profile is shown in the following figure.



Electric load was next broken down into quarterly and weekly demand periods to capture seasonal variation in projected loads and electric generation resource requirements. The resulting quarterly minimum, as well as peak power requirements, is the basis for "sizing" the portfolio of contracts and generation resources needed to serve the County's load profile.

5.5.3 Renewable Portfolio Standards Requirements

The California Renewable Portfolio Standard Program (RPS) established by Senate Bill 1078 requires that a retail seller of electricity purchase a specified minimum percentage of electricity generated by qualifying renewable energy resources. Community Choice Aggregators are required under SB 1078 to procure a specified minimum percentage of total kilowatt hours sold to retail end-use customers each calendar year from renewable resources.

Each distribution utility is required to increase its total procurement of eligible energy resources by at least 1% per year so that 20% of its retail sales are procured from eligible renewable energy resources by year 2017. CCA program aggregated loads are a subset of load currently served by the distribution utilities (SCE, PG&E and SDG&E). Therefore, analyses contained herein assume that customer energy requirements of the prospective CCA will, at a minimum, be equal to the renewable energy percentage required of each distribution utility.

Further, when the County applied for and was accepted into the CCA Demonstration Project it declared as a goal to double the RPS and achieve a renewable energy content of 40% by 2017. The following table reflects distribution utility RPS renewable energy requirements projected forward.

Year	PG&E MIN	SCE MIN	SDG&E MIN
2003		16%	5%
2004	12%	17%	6%
2005	13%	18%	7%
2006	14%	19%	8%
2007	15%	20%	9%
2008	16%	20%	10%
2009	17%	20%	11%
2010	18%	20%	13%
2011	19%	20%	14%
2012	20%	20%	15%
2013	20%	20%	16%
2014	20%	20%	17%
2015	20%	20%	18%
2016	20%	20%	19%
2017	20%	20%	20%
2018	20%	20%	20%
2019	20%	20%	20%
2020	20%	20%	20%
2021	20%	20%	20%
2022	20%	20%	20%
2023	20%	20%	20%
2024	20%	20%	20%

The bill requires the CPUC to adopt rules for implementing the RPS, and CCA planners must understand the renewable energy requirements before they can assess the cost-benefits and make threshold decisions to implement a CCA program. County minimum renewable energy requirements are summarized in the table below.

Renewable Resource Requirements Projected Forward

	Energy MWh	Renewable Capacity (MW) Requirement		Renewable Energy (MWh) Requirement	
		1 X RPS	2 X RPS	1 X RPS	2 X RPS
2007	2,698,210	153	307	403,382	806,765
2008	2,774,526	168	337	442,537	885,074
2009	2,846,487	184	367	482,480	964,959
2010	2,914,186	199	398	523,096	1,046,193
2011	2,977,743	215	429	564,282	1,128,565
2012	3,037,296	231	461	605,941	1,211,881
2013	3,098,042	236	472	619,608	1,239,217
2014	3,160,003	240	481	632,001	1,264,001
2015	3,223,203	245	491	644,641	1,289,281
2016	3,287,667	250	500	657,533	1,315,067
2017	3,353,420	255	510	670,684	1,341,368
2018	3,420,488	260	521	684,098	1,368,195
2019	3,488,898	266	531	697,780	1,395,559
2020	3,558,676	271	542	711,735	1,423,470
2021	3,629,850	276	552	725,970	1,451,940
2022	3,702,447	282	564	740,489	1,480,979
2023	3,776,496	287	575	755,299	1,510,598
2024	3,852,026	293	586	770,405	1,540,810

* Capacity figure is based on a capacity factor of 30%, typical of wind resources.

6 FINANCIAL PROJECTIONS

The supply portfolio modeled for the County contains a diverse mix of resources reflective of a strong commitment to promotion of renewable energy.

The resource types include:

- Spot market purchases – short-term electricity purchases to supplement resources under contract control of the County
- Contract purchases – longer term, fixed price power purchases. Terms can be monthly, quarterly, annual or multi-year. For purposes of this analysis, the contracts were structured with sequential two, three, or five-year terms.
- Natural gas power production – production from a combined cycle natural gas combustion turbine owned by the County used for baseload or shaping purposes
- Renewable energy purchases – purchases of renewable energy to meet the County's renewable resource goals, with a minimum equal to SDG&E's renewable energy mix. For purposes of this analysis, purchases are from a generic renewable portfolio with a cost equal to the weighted average of the renewable resources expected to fulfill California's RPS.
- Renewable energy power production – production from renewable energy resources owned by the County. For purposes of this analysis, an equity position in wind and geothermal facilities sized to meet the County's renewable resource goals
- Off system sales – sales of excess energy into the spot market at times when the resources under contract or ownership are in excess of the County's load requirements

The total cost of service for the CCA program was calculated and compared to the generation costs charged by SDG&E. The difference represents potential savings or costs associated with the CCA program. These savings are shown for each year in the study period, with positive numbers indicating lower costs for the CCA and negative numbers indicating higher costs. Costs or savings are shown both in millions of dollars per year and as a percentage of customers' monthly electric bills.[24]

[24] The percentage savings are expressed based on total electric bills, including SDG&E delivery charges. The percentage savings on the generation component of bills would be approximately double the percentages shown.

Summary Of Electric Cost Savings From Community Choice Aggregation
Base Case Scenario
(Millions of Dollars)

Year	Total CCA Costs	SDG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	207.8	198.6	(9.2)	-2%
2007	210.6	204.7	(5.9)	-1%
2008	213.1	209.6	(3.5)	-1%
2009	228.8	227.6	(1.2)	0%
2010	228.0	237.9	9.9	2%
2011	217.2	232.6	15.4	3%
2012	223.7	247.2	23.5	5%
2013	237.7	257.1	19.4	4%
2014	245.0	266.9	21.9	4%
2015	247.7	278.9	31.2	6%
2016	255.2	287.8	32.6	6%
2017	281.8	305.8	24.0	4%
2018	300.1	336.2	36.1	6%
2019	319.0	364.3	45.3	7%
2020	330.5	379.5	49.1	7%
2021	344.0	384.7	40.7	6%
2022	353.3	396.3	43.0	6%
2023	352.1	402.0	49.8	7%
2024	372.6	431.0	58.5	8%
Total	5,168.2	5,648.6	480.4	5%

Total nominal savings over the study period are $480.4 million or approximately 5% of customers' total electricity costs. Cost savings average approximately $25.3 million per year.

6.1 Supply Portfolio Details

The CCA program would be supplied from a diverse portfolio of energy resources. The portfolio is designed to match SDG&E's renewable energy content. The County invests in generation resources to meet its baseload energy requirements. The portfolio also includes power purchases through contracts with terms ranging from two to five-years and spot market purchases to supplement the production of the County's generation resources.

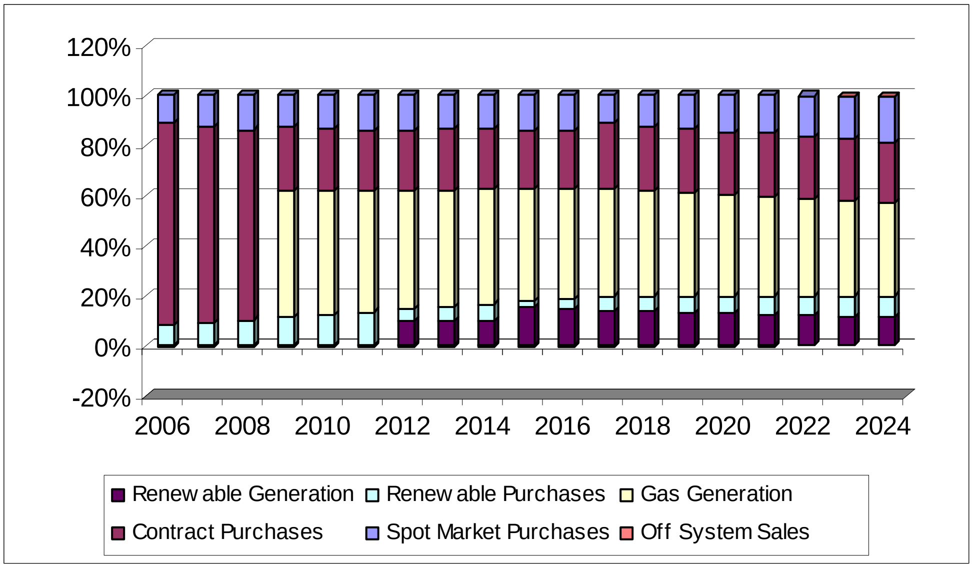
The resource mix includes both conventional and renewable resource ownership. The portfolio initially contains only purchases from the open market, and beginning in 2009, it includes production from a natural gas fueled resource, supplemented by investments in wind and geothermal resources in 2012 and 2015, respectively. 2009 was selected as a feasible date for the County to acquire equity in a new generation resources, considering lead times for negotiations, permitting and financing. Approximately half of the non-renewable portion of the portfolio would consist of new, cleaner burning fossil-fueled plant owned by the County, beginning in 2009.

CCA Generation Resources In CCA Portfolio

Resource Type	Capacity (MW)	On-line	Capital Cost ($ Millions)
Gas Combined Cycle	200	2009	160.2
Wind	120	2012	140.2
Geothermal	25	2015	74.0

The assumed renewable generation resources were sized to meet the majority of the County's renewable energy targets projected for the next several years. As load growth continues, the renewable production must be supplemented with renewable energy purchases to meet the County's targeted renewable percentage of 20%.

Long Term Resource Mix Utilized For Financial Pro Forma



No subsidies are assumed to be available to offset costs of the County's renewable resources. Subsidies are included for renewable energy purchases, to the extent such purchases are needed, consistent with the subsidy treatment discussed in Section 5.3.3.

Capital expenditures associated with the preferred portfolio include startup costs of $400 thousand and generation investments of $160 million in 2009, $140 million in 2012, and $74 million in 2015.

6.2 Alternative Supply Scenarios

Financial pro forma were prepared for four additional supply portfolios that differ by varying the mix of renewable energy in the portfolio and by whether the County owns generation resources used to supply electricity to the program. The pro forma for the alternative supply portfolios are included in Appendix F. Analysis of the alternative supply scenarios can assist the County in understanding the cost effectiveness and tradeoffs among different resources that could be included in a portfolio to supply the CCA program.

6.2.1 Alternative Supply Scenario 1

Supply Scenario 1 assumes the County doubles the renewable content of SDG&E and purchases all of its load requirements from the open market. Inclusion of renewable energy increases the portfolio's cost, even after considering the subsidies potentially available to the County's renewable energy suppliers. The renewable energy costs for purchases up to the minimum renewable portfolio standard are assumed to be offset by supplemental energy payments administered by the CEC, while the incremental renewable energy above and beyond the minimum requirement is assumed to receive no subsidy. Thus, the second 20% of targeted renewable energy is paid entirely by customers of the CCA.

Capital expenditures associated with Scenario 1 is limited to program startup costs estimated at $400 thousand.

This supply strategy results in a loss over the study period of $169.7 million or 2% of total electricity costs.

6.2.2 Alternative Supply Scenario 2

Supply Scenario 2 assumes the County matches the renewable content of SDG&E and purchases all of its load requirements in the open market. Renewable energy subsidies are available to offset the incremental cost of the County's renewable energy purchases.

Capital expenditures associated with Scenario 2 is limited to program startup costs estimated at $400 thousand.

This supply strategy results in a loss over the study period of $96.3 million or 1% of total electricity costs.

6.2.3 Alternative Supply Scenario 3

Supply Scenario 3 assumes the County doubles the renewable content of SDG&E and produces electricity from resources that it owns. The portfolio also includes power purchases through five-year contracts and spot market purchases to supplement the production of the County's generation resources. Supply Scenario 3 includes both conventional and renewable resource ownership. The portfolio initially contains only market purchases similar to Supply Scenario 1, but beginning in 2008, it includes production from wind and natural gas-fired, combined cycle resources.

No subsidies are assumed to be available to offset costs of the County's renewable resources. Subsidies are included for renewable energy purchases, to the extent such purchases are needed, consistent with the subsidy treatment described for Scenario 1.

Capital expenditures associated with Scenario 3 include startup costs of $400 thousand and generation investments of $575 million in 2008.

This supply strategy results in total savings over the study period of $544.6.9 million or 5% of total electricity costs.

6.2.4 Alternative Supply Scenario 4

Scenario 4 is similar to Scenario 3 except that the portfolio matches the renewable content of SDG&E's supply portfolio, with a corresponding increase in the capacity of natural gas fired generation financed by the County.

Capital expenditures associated with Scenario 4 include startup costs of $400 thousand and generation investments of $438 million in 2008.

This supply strategy results in total savings over the study period of $615.8 million or 6% of total electricity costs.

Comparing the alternative supply scenarios reveals the cost advantage enjoyed by the CCA in financing capital-intensive generation projects. The incremental cost of increasing renewable energy from 20% to 40% is not a significant factor in the program's cost-effectiveness.

6.3 Sensitivity Cases

Sensitivity analyses can help put upper and lower bounds on the expected financial results from implementing a CCA program. NCI performed sensitivity analyses for the major variables expected to impact the financial results. The results of these sensitivities are shown below:

- Natural gas and power prices (+/- 25%)
- Cost responsibility surcharges (+/- 50%)
- SDG&E system average rate projections (1.5% to 3% annual growth)
- Rate restructuring proposed by SDG&E in its 2005 Rate Design Window application

None of the sensitivity cases eliminated program savings over the study period. However, in all cases except the low CRS case (Case 4) and the revised SDG&E rate design case (Case 8), revenue losses were incurred in the early years of the program. The County should pay particular attention to changes in these variables if and when it proceeds with implementation of its CCA program. A phase-in of program operations would mitigate exposure to these factors. Another method for accelerating financial benefits would be to create a rate stabilization fund by issuing debt that would be backed by the future revenue streams of the program, thereby moving a portion of future savings forward in time.

Annual financial results associated with the sensitivity cases are shown in the following tables.

Case 1: Base Case

Year	Total CCA Costs	SDG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	207.8	198.6	(9.2)	-2%
2007	210.6	204.7	(5.9)	-1%
2008	213.1	209.6	(3.5)	-1%
2009	228.8	227.6	(1.2)	0%
2010	228.0	237.9	9.9	2%
2011	217.2	232.6	15.4	3%
2012	223.7	247.2	23.5	5%
2013	237.7	257.1	19.4	4%
2014	245.0	266.9	21.9	4%
2015	247.7	278.9	31.2	6%
2016	255.2	287.8	32.6	6%
2017	281.8	305.8	24.0	4%
2018	300.1	336.2	36.1	6%
2019	319.0	364.3	45.3	7%
2020	330.5	379.5	49.1	7%
2021	344.0	384.7	40.7	6%
2022	353.3	396.3	43.0	6%
2023	352.1	402.0	49.8	7%
2024	372.6	431.0	58.5	8%
Total	5,168.2	5,648.6	480.4	5%

Case 2: Natural Gas And Power Prices Are Reduced By 25% From The Base Case

Year	Total CCA Costs	SCE Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	193.3	184.4	(8.9)	-2%
2007	196.3	189.9	(6.4)	-2%
2008	191.3	187.1	(4.2)	-1%
2009	211.0	203.5	(7.5)	-2%
2010	209.1	210.8	1.7	0%
2011	189.4	199.1	9.6	2%
2012	199.5	206.8	7.3	2%
2013	208.1	214.8	6.6	2%
2014	214.2	222.7	8.5	2%
2015	218.2	232.2	14.0	3%
2016	224.6	239.5	14.9	3%
2017	243.9	253.6	9.8	2%
2018	256.2	275.8	19.5	4%
2019	268.8	297.6	28.8	5%
2020	278.3	309.7	31.4	5%
2021	291.2	314.3	23.1	4%
2022	300.0	323.8	23.8	4%
2023	295.1	324.8	29.8	5%
2024	309.6	347.5	37.9	6%
Total	4,498.2	4,737.9	239.7	3%

* For comparison, total savings under the base case is $480.4 million or 5%. Lower natural gas prices reduce savings because lower natural gas and power prices increase the CRS and reduce the SDG&E rate benchmark.

Case 3: Natural Gas And Power Prices 25% Higher Than Base Case

Year	Total CCA Costs	SCE Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	222.2	212.7	(9.5)	-2%
2007	224.8	219.4	(5.4)	-1%
2008	234.8	232.0	(2.8)	-1%
2009	247.6	251.6	4.0	1%
2010	248.5	265.0	16.5	3%
2011	260.7	266.2	5.4	1%
2012	264.1	287.6	23.5	5%
2013	281.4	299.4	18.0	3%
2014	290.3	311.2	20.8	4%
2015	291.7	325.5	33.8	6%
2016	300.5	336.1	35.6	6%
2017	333.9	358.0	24.0	4%
2018	356.6	396.6	40.0	6%
2019	380.0	431.1	51.1	7%
2020	394.1	449.4	55.3	7%
2021	410.8	455.1	44.3	6%
2022	422.1	468.7	46.6	6%
2023	424.7	479.1	54.4	7%
2024	450.0	514.6	64.6	7%
Total	6,039.1	6,559.2	520.1	5%

* For comparison, total savings under the base case is $480.4 million or 5%. Higher natural gas prices would increase savings because higher natural gas and power prices reduce the CRS and increase the SDG&E rate benchmark.

Case 4: CRS Is Reduced By 50% From Base Case

Year	Total CCA Costs	SCE Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	182.6	192.6	10.0	3%
2007	186.8	198.6	11.8	3%
2008	190.6	203.3	12.6	3%
2009	205.3	221.1	15.8	4%
2010	210.7	231.3	20.6	5%
2011	210.5	225.9	15.4	4%
2012	216.8	240.3	23.5	5%
2013	230.7	250.1	19.4	4%
2014	237.9	259.8	21.9	4%
2015	240.4	271.6	31.2	6%
2016	247.6	280.3	32.7	6%
2017	274.2	298.2	24.0	4%
2018	292.3	328.4	36.1	6%
2019	311.1	356.4	45.3	7%
2020	322.4	371.5	49.1	7%
2021	335.8	376.5	40.7	6%
2022	344.9	387.9	43.0	6%
2023	352.1	402.0	49.8	7%
2024	372.6	431.0	58.5	8%
Total	4,965.4	5,526.7	561.4	5%

* For comparison, total savings under the base case is $480.4 million or 5%.

Case 5: CRS Is Increased By 50% From Base Case

Year	Total CCA Costs	SCE Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	233.0	204.5	(28.5)	-7%
2007	234.4	210.8	(23.6)	-6%
2008	235.5	215.8	(19.7)	-5%
2009	249.5	234.0	(15.5)	-4%
2010	245.3	244.5	(0.8)	0%
2011	224.0	239.4	15.4	3%
2012	233.0	254.1	21.1	4%
2013	244.8	264.1	19.4	4%
2014	252.2	274.1	21.9	4%
2015	255.0	286.2	31.2	6%
2016	262.8	295.2	32.5	6%
2017	289.4	313.4	24.0	4%
2018	307.8	343.9	36.1	6%
2019	326.9	372.2	45.3	7%
2020	338.5	387.6	49.1	7%
2021	352.2	392.9	40.7	6%
2022	361.7	404.7	43.0	6%
2023	352.1	402.0	49.8	7%
2024	372.6	431.0	58.5	8%
Total	5,370.7	5,770.4	399.7	4%

* For comparison, total savings under the base case is $480.4 million or 5%.

Case 6: SDG&E Generation Rates Increase At An Annual Rate Of 1.5% Vs. 2.4% Of The Base Case

Year	Total CCA Costs	SCE Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	207.8	198.1	(9.7)	-3%
2007	210.6	207.1	(3.5)	-1%
2008	213.1	215.9	2.8	1%
2009	228.8	224.7	(4.1)	-1%
2010	228.0	233.3	5.3	1%
2011	217.3	241.7	24.5	6%
2012	223.7	250.0	26.3	6%
2013	237.7	258.7	20.9	4%
2014	245.0	267.6	22.6	4%
2015	247.7	276.8	29.1	6%
2016	255.2	286.3	31.2	6%
2017	281.8	296.2	14.5	3%
2018	300.0	306.4	6.5	1%
2019	318.8	317.0	(1.8)	0%
2020	330.3	328.0	(2.3)	0%
2021	343.8	339.3	(4.5)	-1%
2022	353.1	351.0	(2.1)	0%
2023	351.9	346.1	(5.8)	-1%
2024	372.3	358.3	(14.0)	-2%
Total	5,166.8	5,302.5	135.7	1%

* For comparison, total savings under the base case is $480.4 million or 5%.

Case 7: SDG&E Generation Rates Increase At An Annual Rate Of 3% Vs. 2.4% Of The Base Case

Year	Total CCA Costs	SCE Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	207.8	200.8	(7.0)	-2%
2007	210.6	212.9	2.3	1%
2008	213.1	225.1	11.9	3%
2009	226.1	237.5	11.4	3%
2010	228.1	250.0	21.9	5%
2011	217.3	262.7	45.4	10%
2012	223.8	275.6	51.8	11%
2013	237.9	289.1	51.3	11%
2014	245.2	303.3	58.2	12%
2015	247.9	318.2	70.4	13%
2016	255.4	333.9	78.5	15%
2017	282.0	350.3	68.3	12%
2018	300.2	367.6	67.4	11%
2019	319.1	385.7	66.6	10%
2020	330.6	404.7	74.2	11%
2021	344.2	424.7	80.5	12%
2022	353.5	445.7	92.2	13%
2023	352.4	450.6	98.3	13%
2024	372.7	473.5	100.7	13%
Total	5,167.8	6,212.0	1,044.2	10%

* For comparison, total savings under the base case is $480.4 million or 5%.

Case 8: SDG&E Rate Design Window Proposals For Removing Costs And Subsidies From Generation Rates

Year	Total CCA Costs	SCE Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	207.8	206.4	(1.4)	0%
2007	210.6	212.7	2.1	1%
2008	213.1	217.8	4.7	1%
2009	226.1	236.6	10.5	2%
2010	228.0	247.3	19.3	4%
2011	217.3	241.8	24.6	5%
2012	223.8	257.0	33.3	7%
2013	237.8	267.3	29.5	6%
2014	245.1	277.5	32.5	6%
2015	247.8	290.0	42.2	8%
2016	255.2	299.2	44.0	8%
2017	281.8	318.0	36.1	6%
2018	300.2	349.6	49.5	8%
2019	319.1	379.0	59.9	9%
2020	330.5	394.8	64.2	9%
2021	344.1	400.1	56.1	8%
2022	353.4	412.2	58.8	8%
2023	352.2	418.8	66.6	9%
2024	372.6	449.1	76.5	10%
Total	5,166.4	5,875.5	709.1	7%

* For comparison, total savings under the base case is $480.4 million or 5%. Savings improve because the generation rates paid by customers within the County to SDG&E under the new rate designs would increase relative to the current rate structure, creating additional savings achievable by the CCA.

7 EVALUATION OF COSTS AND BENEFITS

This section summarizes NCI's evaluation of the costs and benefits of implementing a CCA program in the County. Evaluation criteria are the ability to deliver lower rates, stable prices, and allowance for increased utilization of renewable energy.

7.1 Ability To Deliver Lower Rates

The economic analysis demonstrates that it is feasible for the County to implement a CCA program. Customers would be able to obtain electric service at rates below those charged by SDG&E within four years of operation. Under the most likely scenario, expected savings average 5% of total electric bills over the study period.

Based on the year-by-year financial projections, NCI concludes that electric bill savings opportunities would begin in year four of program operations and would increase over time. Savings would be dependent upon utilization of municipal debt financing of generation projects or long-term power purchases, assuming current SDG&E rate designs remain in place. If SDG&E's rate design proposals made in its current Rate Design Window proceeding are adopted, the CCA benefits would improve to approximately 7%, on average over the study period, and begin to accrue in the second year of program operations (See sensitivity Case 8 in Section 6.3). With the proposed SDG&E rate designs, a CCA program would be economically viable even without investment in generation, producing slight savings of approximately 1% on average over the study period.

The range of expected cost savings may be sufficient in and of themselves to justify the decision to pursue CCA. The estimated cost savings also help support and justify the decision to pursue CCA to achieve other benefits, such as rate stability, local control, and increased opportunities for renewable energy development.

7.2 Rate Stability

The County could structure its portfolio to emphasize cost predictability and provide stable prices to CCA customers. Long-term supply contracts at fixed prices can provide predictable costs for terms of ten years or longer. Investments in renewable resources, such as wind resources, solar, biomass and geothermal, eliminate the dependence on natural gas and the exposure to fluctuations in natural gas prices for that element of the supply portfolio.

The sensitivity analysis shows an expected range of program savings of between 1% and 10% over the study period. The County's portfolio would demonstrate relatively stable prices to consumers. Under the base case scenario, which reflects conservative assumptions regarding future increases in SDG&E's rates, the CCA program costs are expected to show 25% greater stability than SDG&E's rates.

7.3 Increased Utilization Of Renewable Energy

The County would determine how much renewable energy to include in its portfolio, over and above the minimum percentages required pursuant to the California RPS. The cost of purchasing renewable energy is greater than the costs of purchasing electricity produced from fossil fuels, so exceeding the RPS via power purchases will increase the average cost of the County's portfolio to some degree. However, the analysis shows that doubling the RPS would have only a modest overall impact on customer bills, as discussed below.

7.3.1 Cost Of Renewable Energy

The CEC's Renewable Resources Development Report (RRDR) published in November 2003 shows the mix and costs of the renewable resources that will likely be utilized to meet the California RPS. The cost of buying renewable energy can be estimated by creating a generic portfolio of these resources using the contributions for each type projected in the RRDR study to calculate a weighted average cost. The average cost of these resources, weighted by their expected contribution to the RPS, is shown below:

Renewable Resource Technologies Expected To Fulfill The California Renewable Portfolio Standard (2003 Dollars)
Source: CEC Renewable Development Resource Report

Resource	Portfolio Contribution	2005 Levelized Production Cost ($/MWh)
Wind (Class 4 site)	66%	60 *
Concentrating Solar	1%	121
Landfill Gas	4%	44
Solid Biomass (Direct Combustion)	4%	66
Geothermal (Binary)	25%	55
Weighted Average		59

* The cost of wind is based on the levelized cost of $49 per MWh presented in the RRDR plus an additional $11 per MWh capacity cost to reflect that capacity must be acquired separately because of the intermittency of wind resources. These figures do not include production tax credits, which many people believe will be reinstated once Congress passes a comprehensive energy bill.

Escalating the cost to 2006 by assuming 2.5% annual inflation yields a 2006 average renewable cost of $62 per MWh. This represents a premium of approximately $16 per MWh above the projected market prices of system power in 2006.

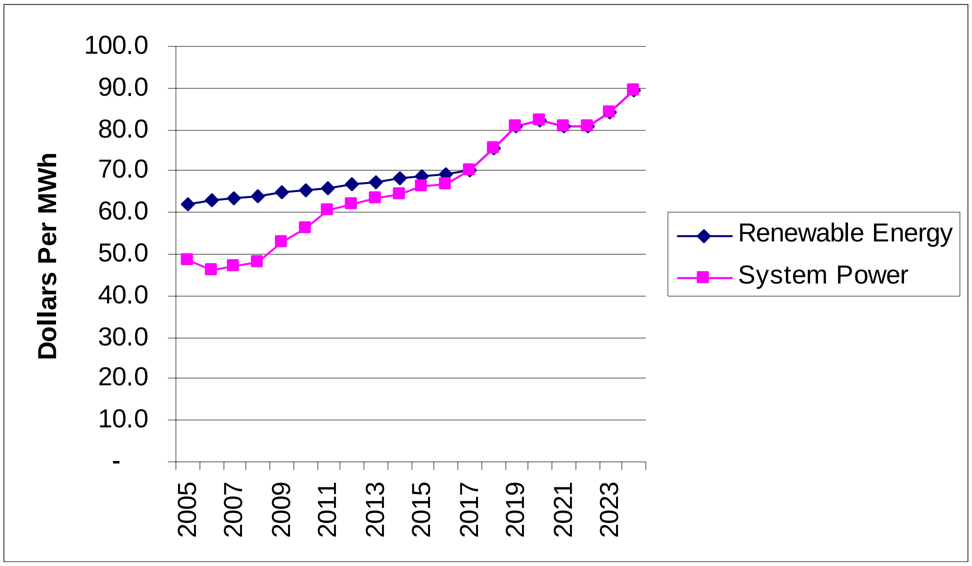
All else being equal and assuming no County capital financing of renewable energy, the cost of doubling SDG&E's 7% renewable mix would be $16/MWh * 0.07 = $1.12 per MWh. A typical household would pay $0.56 more per month to double the amount of renewable energy used to supply its electricity consumption.[25] The premium declines over time as natural gas and electricity market prices are expected to rise faster than the cost of renewable energy production. For instance, assuming average annual increases in the market price of system power of 2.8% used in this study, the renewable price premium falls to $4 per MWh by 2014. By 2018, the market price of renewable energy is expected to be no greater than the cost of conventional generation resources.[26]

[25] Typical residential consumption is approximately 500 kWh or 0.5 MWh per month.

[26] The cost of transmission investments that may be needed to bring large amounts of renewable energy to load centers is not included in this analysis. These costs will be included in transmission rates that are paid by all users of the grid and should not impact the CCA economic analysis.

The projected costs of renewable and conventional electricity are shown in the following chart:

San Diego Area Market Price Projections For Renewable And Conventional Electricity



7.3.2 Municipal Financing of Renewable Energy Development

As described in this feasibility study, the County can reduce the cost of acquiring renewable energy by financing development of renewable resources used to supply its CCA program. The following table compares the total cost of a hypothetical 100 MW wind energy project utilizing the financing structures typical of an investor owned utility vs. those available to the County. The underlying assumptions are that the utility's capital structure is comprised of 50% debt and 50% equity at an overall cost of capital of 9%, while the County employs 100% debt financing at a rate of 5.5%. The utility is subject to federal and state income taxes of 40.75% so that the tax-effected cost of capital is 12.9%. The County makes no return, has no income tax obligation and establishes its revenue requirement based on the cash requirements needed to cover expenses and debt service. [27]

[27] Section 8.1.6 discusses financing options available to the County's CCA program.

Cost Comparison – IOU Vs. County Ownership of Wind Resource (Thousand of Dollars)

Cost Element	Investor-Owned Utility	County
Capital Cost ($000)	15,951	7,730
Operations & Maintenance ($000)	2,198	2,198
Firming Capacity ($000)	3,022	3,022
Total First Year Cost ($000)	21,171	12,950
Cost Per MWh ($/MWh)	77	47

The capital-related costs are significantly less if the County were to own or otherwise finance the resource, compared to ownership by an investor owned utility such as SDG&E. The costs of maintaining and operating the resource would be the same, as would be the cost of capacity needed to "firm" the wind resource's intermittent production. The use of low cost debt and greater financial leverage by the County reduces the annualized costs. During the first year of operation, the County can produce energy at a cost that is nearly 40% lower than what the investor owned utility would incur if it owned the identical resource. The County's cost of producing renewable energy would be nearly the same as the market price of system power.

7.3.3 Operational Issues For Renewable Energy

Renewable resources are generally non-dispatchable, operating as either baseload resources or on an as-available basis. Wind and solar resources produce electricity only during certain times of the day when there is sufficient wind or sun. These characteristics place an operational limit on the amount of renewable energy that can be included in the overall resource mix. Depending on a community's load duration curve, which defines its base load requirements, the operational limit could range between 50% and 70%.[28] It would be possible to exceed these amounts by over-procuring, but doing so would require the Aggregator to sell excess energy into the market during many hours of the year, thereby taking on additional risks associated with wholesale sales of energy.

A similar issue exists with reliance on intermittent wind production. If an Aggregator with an average load requirement of 200 MW established a 50%

[28] This refers only to the County's program operations and is not intended to imply that the entire system could efficiently integrate such large amounts of renewable energy.

renewable target, it would need approximately 300 MW of wind capacity. With a typical capacity factor of 32%, production from 300 MW of wind capacity would average the 100 MW needed to meet the target. However, at any moment in time, the Aggregator could have between 0 and 300 MW of production. The Aggregator would either need to purchase 200 MW of replacement energy or it would have 100 MW excess energy to sell. These imbalances impose financial risk on the Aggregator as the prices at which it must buy and sell energy may not be identical. [29]

One way that the CCA could safely exceed the operational limits on renewable energy is by purchasing renewable energy certificates (RECs) from producers of renewable energy. The CEC is currently investigating a system that would facilitate trading of RECs, and private markets for RECs have been in existence for several years. The tradable REC concept allows the renewable attribute associated with renewable energy production to be sold separately from the electrical energy. Through appropriate tracking and verification, the buyer can be assured that for each REC purchased a kWh of renewable energy was produced during the year; however, the renewable production need not match the buyer's load requirements on an hour-by-hour basis. By separating the renewable attribute from the electrical energy, a CCA could ensure that enough renewable energy was produced over the course of the year to supply 100% of its customers' load requirements, while avoiding the need to sell excess energy. The price of the REC should be approximately equal to the cost difference between the market price for system power and the cost of renewable energy production, after considering all available incentives.

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[29] Firming services are available via contract with energy suppliers, typically those with significant hydroelectric resources in their portfolio.

8 REGIONAL COMMUNITY CHOICE AGGREGATION PROGRAM OPERATED UNDER A JOINT POWERS AGENCY

8.1 Economies Of Scale From Combined CCA Operations

By combining the electric loads of multiple cities and/or counties for CCA operations, scale economies can be achieved that increase the benefits available to the individual members. Operational cost saving can be captured through common program administration and energy procurement activities. Diversity among community load shapes enables the sharing of capacity reserves, lowering overall procurement costs. The flatter load shape of a combined CCA program reduces the costs of serving the load, thereby increasing the benefits available to each of the participating communities.

8.2 Joint Powers Agency Structure Option

Joint Power Agencies (JPA) are common legal structures that many public agencies have formed and used to offer services in a more economical and efficient manner. CCA JPA formation can combine city and county jurisdictions to secure long-term power contracts or develop its own generation resources. Multiple member CCA JPAs may benefit from flatter electric load shapes, reducing the overall cost to serve. There are numerous operating examples of jurisdictions forming JPAs to procure electric energy in wholesale markets for delivery to member constituent retail markets. The following describes some of the benefits and impediments of the CCA JPA structure option:

<u>Summary of Benefits</u>

- The JPA structure enables its party agencies to jointly exercise any power common to them. CCA enabling legislation cites eligible jurisdictions as cities, counties or JPAs comprised of cities and counties.
- The CCA JPA will be a governmental agency and its motives are not profit driven.
- Parties to the JPA would share cost/risk and assist with any JPA project.
- JPA formation can combine its members in securing long-term power contracts or entering into agreements with agencies in the development of generation resources.
- JPA members could benefit from economies of scale associated with building a large project with its greater plant efficiencies and lower unit costs.

- The JPA may authorize the issuance of low cost bonds by ordinance subject to referendum but without a vote of the electors within the public entities comprising the JPA
- A JPA provides an organizational, legal and financial structure to integrate its parties and facilitate the implementation and operation of projects (in this case utilities)
- This structure minimizes direct exposure of the member jurisdictions and at the same time provides a conduit to key capital, political, and intellectual resources for the other JPA members.
- This structure could reduce or eliminate the need for redundant personnel and systems to facilitate energy supply for the multiple member jurisdictions.
- JPA Operational Business Plans could incorporate phased customer segment participation and provide flexibility to subcontract the organizational depth needed during initial CCA operation.

Summary of Impediments

- Forming a JPA is time consuming; it is necessary to establish a working group or advisory panel of all parties, and parties must agree on approach and structure (the fewer the parties the more streamlined the process).
- The challenge for governance is to provide equitable representation for both large and small members without compromising either's options.
- The decision-making process can be cumbersome, during both formation and operation (decisions tend to be "consensus" driven, slowing processes and compromising positions - members seek to protect their own interest).

8.3 Purpose and Parties

A JPA is formed when it is to the advantage of two or more public entities with common powers to consolidate their forces to acquire or construct a joint-use facility or when local public entities wish to pool with other public entities to save costs to acquire equipment or to acquire or construct facilities for their individual use. A joint exercise of powers agreement must be approved by all participating entities, and this may include the federal government or any federal department or agency, this state, another state or any state department or agency, a county, county board of supervisors, city public corporation, or public district of this state or another state.

8.4 Authorization

A Joint Powers authority is empowered by Chapter 5, commencing with section 6500 of Division 7 of Title 1 of the Government Code, to issue bonds, notes, Commercial paper, including certain kinds of variable rate securities for specified purposes, and to enter into leases to acquire land and equipment or to acquire or construct public facilities. The JPA entity is created when member jurisdictions enter into a joint exercise of powers agreement, forming a joint powers agency and by adopting identical concurrent, ordinances.

8.5 JPA Governance

A commission responsible for administering the CCA JPA would be established and comprised of representatives from each party to the CCA JPA Joint Powers Agreement. A quorum of the CCA JPA Commission (Commission) would consist of those Commissioners, or their designated alternatives, representing a numerical majority of the Parties. Voting on JPA actions could be facilitated wherein each Party would have the right to cast one vote. In the alternative, voting may be conducted where each party has a number of votes equal to its percentage share of CCA JPA expenses. Such procedures would be developed by a working group or advisory panel of all parties as referenced above.

In addition to voting representation on the Commission, flexibility for Parties to take actions alone or in concert with other selected JPA members, and thereby ensure members can protect and pursue individual interests, can be facilitated through the development and use of a hierarchy of structured agreements. In the example below, precedence of agreements can be established where, for example, a Project or Operating Agreement takes precedence over a Facilities Agreement. In this case action can be taken by JPA members without executing a higher-level membership-wide agreement. In this way specific operational arrangements between a limited numbers of Parties take "precedence" over higher-level membership-wide agreements. The names and use of agreement structures would be adjusted to more closely reflect CCA JPA activities. The following is an example of hierarchical of JPA Agreements used by the Northern California Power Agency:

Agreement Hierarchy:

1. Joint Powers Agreement
2. Pooling Agreement
3. Facilities Agreement
4. Project Agreement
5. Operating Agreement

Joint Powers Agreement: Through the Joint powers Agreement a CCA might be established as a public agency pursuant to the Joint Exercise of Powers Act of the Government Code of the State of California authorized to acquire, construct, finance and operate buildings, works, facilities and improvements for the generation of electric capacity and energy for resale. Each of the Parties to the Agreement would be a city or a county jurisdiction authorized to implement a CCA pursuant as defined in enabling legislation AB 117 (Migden – Chapter 838, Statutes of 2002).

Pooling Agreement: Each Party to the Pooling Agreement is a Party to the CCA Joint Powers Agreement. The Pooling Agreement establishes facilities, staff, and the capability for: Planning for the addition of facilities; entering into long-tem and short-term, firm and non-firm interchange transactions; dispatching and scheduling all available resources to meet the combined loads of the Parties.

Facilities Agreement: A Participant in a CCA Facilities Agreement is a CCA JPA member and a signatory to the CCA Joint Powers Agreement (JPA). The Facilities Agreement provides a framework for membership joint design, construction and operation of power supply facilities.

Project Agreement: Establishes the framework for the development, design, financing, construction and operation of specific projects.

Operating Agreement: Detailed descriptions, principles and procedures (including operating and cost recovery) for CCA JPA projects.

8.6 Revenue Bond Issuance

The JPA may authorize the issuance of revenue bonds by ordinance subject to referendum but without a vote of the electors within the public entities comprising the JPA. However, JPAs may also issue securities pursuant to a resolution of the authority backed by loan agreements and/or bond purchase agreement with participating member agencies. The law provides that some but not necessarily all of the members of a JPA may participate in a bond issue and that only those participating will be obligated to repay the debt incurred.

Below we list a number of financing alternatives to consider once a JPA has been formed.

Comparative Features of Alternative Financing Methods

Financing Method/Characteristics	General Obligation Bonds	Limited Obligations Bonds	Special Assessment	Certificates of Participation	Revenue Bonds
Project Financeable	Acquisition & improvements of land and buildings	Acquisition & improvements of land and buildings	Facilities of local benefit to property	Unrestricted	Revenue producing facilities
Authorization	Issuer's governing board & public election (2/3 vote)	Resolution of issue governing board and 2/3 vote	Resolution of issuer, petition of beneficiaries	Resolution of issuer governing board	Resolution of issuer governing board
Area of Authorization Jurisdiction	Boundary of issuer facilities district (flexible)	Boundary of issuer facilities district (flexible)	Flexible	N/A	Service area of issuer
Hearing Procedure	None	None	Majority protest hearing	Maybe ordinance adoption	None
Validation	None	None	None	None	None
Nature of debt service payments	Unlimited ad valorem tax	Portion of current revenues	Annual assessments based on benefits received; property taxes may not be used	Rental or installment payments	Service charges and fees from users
Source of debt service payment	Property owners in issuer jurisdiction	General revenues of issuer	Annual property assessments	General &/or enterprise revenues of issuer	Service charge and fee collections
Security	Full faith and credit	Revenue collections and coverage test	Tax collections/ Foreclosure	Lease or installment sale contract	Coverage test and contracts
Lessor/Lessee Required	No	No	No	Yes	No
Refundable	Yes	Yes	Yes	Yes	Yes
Debt Service Funds subject to Gann Limit	No	No	No	Yes	Yes
Structural Features					
Reserve Fund	No	Yes	Yes	Yes	Yes
Capitalized Interest	No	No	Yes	Yes	New enterprise only
Debt Service Coverage	No	Yes	Value/lien ratio 3:1	No	Yes
Method of Sale	Competitive or Negotiated	Competitive or Negotiated	Competitive or Negotiated	Competitive or Negotiated	Competitive or Negotiated
Advantages	Lower interest rate	No pledge of General Fund	Isolates projects	No voter approval	Lower interest rate
Disadvantages	Voter approval required	Voter approval	Limited security Higher interest rates	Highly structured Limited flexibility	Debt Service Reserve Fund

The overview above provides a broad perspective on the various financing techniques that will be available to a CCA JPA. However, the ultimate method that the CCA JPA chooses will based on a number of factors:

Purposes of Financing: Proceeds of the financing can be used for a number of different uses including but not limited to: Start-up costs, construction of new plant and equipment, initial capital for power purchases, Operations and maintenance expenses among others. As outlined above, the purpose of the financing can and will affect the type of bond issue that the CCA JPA can utilize to finance its various costs. In the end the JPA may execute a series of different products to meet each of its various purposes.

9 CONCLUSIONS AND RECOMMENDATIONS

9.1 Conclusions

There are three general criteria, as described under Section 7, for assessing benefits of CCA. These are the potential for reduced rates, the ability to increase utilization of renewable energy, and enhanced local control/rate stability. This analysis shows it is possible to achieve each of the three objectives by forming a CCA program, under the most likely scenarios. Formation of a CCA program offers benefits but is not entirely without risks, both financial and political. The County should clearly define its reasons for pursuing CCA so that program implementation reflects and fulfills clearly defined objectives. These reasons could include one or more of the following goals:

- Proactively address energy and infrastructure issues in the community
- Expand use of renewable energy resources and increase energy efficiency (e.g., reduce greenhouse gas emissions, reduce dependence on fossil fuels and imported natural gas)
- Reduce energy costs or enhance public benefit funding
- Provide for electric rate stability and local control
- Provide other utility services, such as energy efficiency and distributed generation
- Increase the tools available for economic development and planning
- Position County for provision of expanded electricity service offerings in the future

The primary risks of providing aggregation services to customers are:

- Under some scenarios that have a reasonable chance of occurring, program rates could be up to 3% higher than those offered by SDG&E, particularly within the first three years of program operations. Under the worst-case scenario, program rates could be 4% to 7% higher than those offered by SDG&E during the first four years.
- The County would be undertaking resource obligations on behalf of participants and such investments could ultimately prove to be uneconomic
- Risks inherent in procuring electricity for retail customers can be significant and must be properly managed or laid off to the program's energy suppliers

Ultimately, a primary benefit of CCA is giving consumers greater control over their energy choices and devolving responsibility for energy planning to the local level. The County should take a long-term view in considering the decision to form a CCA program and be prepared to weather challenges that may arise in the short-term. A staged approach to implementation, both with respect to the number of customers participating in the program and the level of direct involvement by the County in the program's operations (procurement, risk management, resource development, etc.), would be advisable to avoid potential pitfalls as the County embarks on a new enterprise of this magnitude. More specific information regarding benefits and risks will become known as the County obtains offers from electricity service providers during the development of its Implementation Plan, and there will be an additional decision point at that time on whether to proceed with program operations.

Participation in a regional CCA program via formation of a joint powers agency would offer benefits of scale that would not be available under a standalone program. The County should explore opportunities for joining with other local governments in the region to form a regional CCA program if the County decides to move forward with implementation.

Lower Rates

The analysis indicates the County is likely to obtain cost savings equal to approximately $25.3 million per year or approximately 5% of customers' electricity bills on average over the study period. These cost savings could be used to reduce rates and/or to create a new revenue stream for public benefit funding. The sensitivity analysis shows that savings are not dependent upon the specific financial assumptions underlying the base case over the long term. The average program savings range from a low of 1% to a high of 10% across the seven cases evaluated to test the sensitivity of these results to changes in wholesale energy market conditions, SDG&E rate projections, and cost responsibility surcharges.

A conservative interpretation of these findings suggest that over the next several years there would be little ratepayer benefit from implementing a CCA program, primarily due to the imposition of cost responsibility surcharges on CCA customers. Indeed, the study indicates that rates would likely be slightly higher than those offered by SDG&E for the 2006 to 2009 time period. Cost benefits should materialize over the longer term as the CRS begins to decline and eventually expires.

If achieving lower rates in the near-term is a primary motivation for the County's investigation of CCA, NCI recommends awaiting the outcome of SDG&E's current Rate Design Window proceeding before committing to CCA implementation. The CPUC's approval of SDG&E's rate design proposals to reallocate generation costs among customer classes would change the near-term outlook for a County CCA program, making cost savings achievable as early as 2007.

Increased Renewable Energy

The analysis shows that a 40% renewable energy target could be achieved with no rate increases for customers if the County is willing to finance renewable resource development to supply the CCA program (See Alternative Supply Scenario 3 in Section 6.2.3 and the pro forma in Appendix F). The cost effectiveness of increasing renewable energy utilization to this degree is greatly enhanced by the involvement of the public sector through CCA because of the public sector's access to low cost capital and the contract coverage afforded by the CCA's large customer base. A primary benefit of forming a CCA program is to create the ability to increase utilization of renewable energy. A realistic implementation approach would incorporate a hybrid supply strategy and gradual ramp-up of renewable energy utilization, initially utilizing contracts with third parties to match the SDG&E renewable energy mix and eventually progressing to municipal ownership/financing of generation.

Local control/rate stability

Ultimately the long-term benefits of a CCA program in the community resolve around local control. Such control includes the ability for the County and aligned agencies to effect resource planning and infrastructure investment in an integrated fashion responsive to the community's needs and values. Local control also manifests in avoiding the cost consequences of the utility's long-term procurement decisions, which must be made considering the competing interests of shareholders, regulators, and consumers. The County faces no such conflicts and can focus on its primary mission of representing the interests of consumers.

9.2 Recommendations

1. Communicate final study results through community workshops and identify next steps in proceeding toward Implementation Plan filing.

2. Consider whether natural alliances exist among neighboring communities, and explore partnering arrangements to optimize supply side alternatives and regional CCA implementation.

3. Monitor the outcome of SDG&E's current Rate Design Window proceeding.

4. Make decision whether to proceed with development of an Implementation Plan.

APPENDICES

Appendix A – Resource Portfolio Planning Template

Fifth Supply Scenario Variables

1. Renewable Energy (RE) Targets
    a. End-State Percentage (20-100% by 2017) ________
    b. RE Ramp Rate 2006 – 2023, Cite Yearly Targets
        1) 2006 min. 14%
        2) 2017 min. 20%
    c. RE Equity Position
        1) Physical Resource Entitlement (ownership/investment)
            a) Yes __ No __
            b) Percentage of Total RE __
            c) In-Service Dates and Capacities (MW)
        2) Market Purchases
            a) Percentage of Total RE __
            b) Contract Schedule and Capacities (MW)
2. Conventional Generation Resource Equity Position
    a. Physical Resource Entitlement (ownership/investment)
        1) Yes __ No __
        2) In-Service Dates and Capacities (MW)
    b. Market Purchases - Contract Schedule and Capacities (MW)
3. Distributed Generation
    a. Capacity (kW)
        1) Existing
            a) Technology (PV/micro-turbine/etc)
            b) Capacity (kW)
            c) Energy (kWh)
            d) Cost
            e) In-Service Dates
        2) Planned
            a) Technology (PV/micro-turbine/etc)
            b) Capacity (kW)
            c) Energy (kWh)
            d) Cost
            e) In-Service Dates
4. Spot Market Purchases (assumed minimized – under 15% energy unless instructed otherwise)

5. Based Upon the 5th or "Preferred" Supply Portfolio Sensitivities Will be Assessed for the Following Variables:
    a. Natural gas/power prices (+/- 25%)
    b. Cost responsibility surcharge (+/- 25%)
    c. IOU rate projections (+/- 5%)
    d. IOU rate design (GRC proposals)
    e. Renewable subsidies (SEP, PTC)
    f. Combined operation with other Project participants

Appendix B – Detailed Assumptions

Key Assumptions Used In CCA Feasibility Analysis and Modeling – San Diego Gas and Electric Territory

1) Metering and Billing

   a) No new metering requirements for CCA customers.
   b) Billing charges same as direct access from Schedule DA.
   c) Billing charges based on rates from Schedule DA.

2) Financing

   a) Tax exempt financing for startup costs and any new generation development @ 5.5%.
   b) 100% debt financing.
   c) Financing term is 30 years.
   d) Minimum debt coverage ratio of 1.25.
   e) Bond insurance cost of 1.6% of par value.
   f) Bond transaction cost of 1% of par value.
   g) Debt reserve of 10% of par value.

3) Startup and Operations Costs

   a) Startup costs include regulatory and legal @ $350,000.
   b) Operational costs are outsourced @ $2.50 per MWh unless and until CCA reaches approximately 1.5 million MWh in sales.
   c) If performed internally, the cost is estimated at $3.9 M per year plus 10 cents per MWh, including IT.
   d) Activities include scheduling coordination, procurement/planning, risk management, credit, rates and load research, A&G, and IT.
   e) The CCA will begin serving customers in January 2006
   f) Working capital costs are based on one-month lag between payables and receivables, financed at an annual rate of 5%. Costs are included in the program's supply costs and would be funded by the program's energy supplier.

4) Resource Adequacy

a) CCAs subject to same resource adequacy requirement as IOUs, per D.04-01-050.
b) Planning reserves are required to bring total reserves, including ISO required ancillary services, up to 15% of peak load.
c) Costs of meeting planning reserves equal to market value of capacity.
d) Spot market purchases limited to between 5% and 20% of CCA portfolio; the remainder of the portfolio is comprised of long-term contracts and/or resource ownership.

5) Renewable Energy Portfolio

a) Renewable purchases are from a generic portfolio comprised of Class 4 Wind, Binary Geothermal, Solid Fuel Biomass, Land Fill Gas Biomass, and Concentrating Solar Power.
b) The cost and resource mix comprising the portfolio is derived from the CEC's Renewable Resources Development Report (11/7/03) See RRDR, Table 4, page 37 and discussion at page 87. 2005 costs are escalated at a nominal rate of 1% per year.
c) The cost of the generic renewables portfolio equals the estimated developers' costs, including return on investment. Market price of renewable energy equal to maximum of cost or market price of system energy
d) The cost of wind energy assumes no extension of the production tax credit.
e) Wind energy must be firmed via capacity contracts due to its intermittent nature. The cost of wind energy is adjusted for a capacity adder to firm the intermittent resource, at market value of capacity.
f) Renewable ownership costs are derived by applying municipal financing assumptions to the cost data in RRDR Appendix D, page D-6. 2005 costs are escalated at a nominal rate of 1% per year.
g) Ownership cost incorporate technology specific assumptions regarding installed capital costs, fixed operations and maintenance, capacity factor, fuel cost, and capacity cost adder applied to intermittent resources.
h) The ownership costs of intermittent resources also includes a risk factor of $5 per MWh related to the potential differences between energy prices for sales from excess production versus purchases for production shortfalls.

i) CCAs will rely primarily on large-scale renewable projects to meet and exceed the RPS. These are Wind, Geothermal, Solid Fuel Biomass, and Concentrating Solar Power.
j) CCA owned generation resources can be online by 2008.
k) Distributed generation options, such as rooftop PV systems, are incorporated in the feasibility analysis based on community specific planning. Renewable DG production, if any, will be in addition to the RPS minimums.
l) Supplemental energy payments are available to offset the incremental costs of renewable contract purchases (10-Year Terms) up to the minimum RPS requirement. PGC funds are sufficient to buy down 100% of the cost premium of renewables.
m) Supplemental energy payments are not available for CCA-owned resources and not available for purchases in excess of the RPS minimums.
n) CCAs are required to match the renewable energy percentage of the respective investor owned utility in the first year of CCA operations.
o) IOU renewable baseline percentages are derived from RRDR Appendix A, page A-2 and increased by 1% per year until 20% is achieved by 2017.

6) <u>Wholesale Energy Markets</u>

a) Electricity market price forecast based on projected market clearing system heat rates and natural gas price projections.
b) Natural gas price projections prepared by NCI in January 2005.
c) Heat rates for 2005 - 2010 are 8,000, 8250, 8700, 9000, 10000, 10500. Market equilibrium assumed at heat rate of 11000 after 2010.
d) On-peak energy priced at 15% premium; off-peak energy priced at 15% discount; real time energy at 10% premium.
e) Long-term contracts priced at 5% premium to expected spot market prices.
f) Capacity costs valued at $100,000 per MW-Year, escalated at 2.5% annually; costs are embedded in energy prices derived as above.
g) Ancillary services and related costs estimated based on historical relationship to market prices, projected forward.
h) Ancillary services requirements based on percentage of CCA's load per current CAISO practice.
i) Ancillary services types are Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve.

j) California Independent System Operator (CAISO) administrative and neutrality charges are derived from current rates, escalated at 2.5% annually.
k) CAISO charges are Grid Management Charge - Control Area Service, Grid Management Charge - Inter-zonal Scheduling, Grid Management Charge - Ancillary Services and Real Time Operations, Unaccounted For Energy Charge, Neutrality Charge, Congestion Charge, De
l) No explicit modeling of impact from move to locational marginal pricing; assumed that loads will be protected from congestion costs by allocation of congestion revenue rights and zonal averaging of prices
m) Distribution losses are 7%.

7) <u>Generation Cost</u>

a) CCA's choosing to own generation will acquire equity interests in combined cycle gas turbine facilities based on the following cost and operating parameters:
b) Installed cost of $700 per KW.
c) Heat rate of 7,000 mmbtu/MWh.
d) $3 per MWh fixed and variable O&M.
e) 0.1 pounds per MWh emissions..
f) $10 per pound cost of NOx emissions.
g) 90% planned capacity factor.
h) 2% forced outage rate.
i) Excess sales sold at prevailing market clearing prices.

8) <u>Cost Responsibility Surcharges</u>

a) Cost responsibility surcharges calculated annually using total portfolio indifference method adopted in direct access proceeding (includes old and new resources) (R.02-01-011) and CCA rulemaking (D.04-12-046)
b) CRS reduced by pro rata share of cost of ancillary services and planning reserves
c) No cap on cost responsibility surcharge for CCAs.
d) Cost responsibility surcharge includes DWR bonds, DWR power charge, and utility CTC; No historical procurement charge.
e) Uniform "indifference fee" per KWh for all CCA customers, regardless of rate class and CCA startup date. No baseline credits reflecting AB1X protections for residential consumption up to 130% of baseline allocation.
f) Uniform DWR bond charge per KWh, statewide.

g) CTC rate varies by customer class based on current tariffs. AB 265 undercollection fully recovered by 2005.
h) DWR bond charge based on currently applicable rate as of January 2005.
i) No transfer to CCA of DWR contracts, renewable energy, or capacity contracts implied by payment of cost responsibility surcharges.

9) <u>IOU Rate Projections</u>

a) IOU rates for generation are the competitive reference point for assessing CCA cost savings potential.
b) Current IOU rate schedules (February 2005) applied to CCA customer billing determinants (estimated), aggregated by major rate group.
c) Generation rates and total rates (generation plus non-generation) projected forward based on percentage changes in IOU system average rates.
d) IOU generation costs projected based on current resource mix, adjusted over time for planned generation retirements, DWR contracts, QF contracts, new SDG&E generation (Palomar), new power purchase contracts (Otay Mesa and generic) and renewable energy contracts to meet RPS.
e) SDG&E owned generation resources includes 20% share of SONGS, declining to 17% in 2010. SONGS continues to operate due to steam turbine replacement. SONGS capital and operating and maintenance expenses based on SDG&E projections in its 2003 General Rate Case (A.02-05-004) and SDG&E's 2006 General Rate Case.
f) Generation costs and beginning rate base for each generation type are derived from 2003 Cost of Service filing (A.02-12-028).
g) Generation costs include operations and maintenance, return, depreciation, uncollectibles, A&G, franchise fees, taxes other than income, taxes based on income, fuel, thermal decommissioning, and other.
h) Purchased Power includes QF contracts, existing bilateral contracts, DWR contracts, new renewable contracts, new bilateral contracts, and spot market purchases.
i) New bilateral contracts entered into as needed to maintain spot purchases (residual net short) at or below 10% of IOU portfolio.
j) SDG&E maintains planning reserves of 15% of annual peak load. Existing ancillary services requirements are included in the 15% planning reserves requirement.
k) Spot market purchases to meet the residual net short are priced at average of SP15 peak (6 X 16) and base (7 X 24) power prices.

l) Majority of QFs paid according to settlement price through 2007, and then based on annual short run avoided cost formula.
m) QF capacity payments derived from FERC Form 1 data.
n) QF capacity/energy projections and SDG&E load forecast derived from the Consultant's Report supporting DWR bond financing.
o) RPS purchases from generic renewable portfolio as described above; Supplemental Energy Payments fully offset incremental costs relative to non-renewable energy.
p) DWR costs and volumes adjusted over time based on terms of the individual contracts allocated to SDG&E per D.02-09-053.
q) DWR "remittance rate" calculated using CPUC methodology (D. 04-12-014).
r) Cost offset for bundled customer generation costs from cost responsibility surcharges paid by Direct Access Customers based on capped collection rate from direct access proceeding (R.02-01-011).
s) Non-generation costs escalated at constant 1.5% per year. Non-generation rates are only used to express the CCA cost impacts as percentage of customers' total electric bills.
t) Same input assumptions as above for wholesale electricity prices, capacity prices, natural gas prices, ancillary services costs, CAISO charges, RPS % and prices, supplemental energy payments, and DWR bonds charges.

Appendix C – Sample Data Request Letter

[DATE]

San Diego Gas and Electric Company

Attention: [LOCAL GOVERNMENTAL AFFAIRS REPRESENTATIVE NAME]

101 Ash Street

San Diego, CA 92101

SUBJECT: Information Request Per D.03-07-034

Dear [LOCAL GOVERNMENTAL AFFAIRS REPRESENTATIVE NAME]:

The [CITY OR COUNTY] of [NAME] (CITY OR COUNTY) is currently reviewing its options in becoming a Community Choice Aggregator (CCA), in accordance with legislation enacted in 2002 (Assembly Bill 117), for: 1) administering energy efficiency programs; and 2) possibly providing electrical energy as related to this legislation. On July 10, 2003, the California Public Utilities Commission (CPUC) approved an "Interim Opinion Implementing Provisions of Assembly Bill 117 Relating to Energy Efficiency Program Fund Disbursements" (Decision 03-07-034). As part of this Decision, the CPUC directed San Diego Gas and Electric Company (SDG&E) to provide certain types of information to cities, counties, and CCAs.

The [CITY OR COUNTY] respectfully requests the information listed below, as enumerated in Attachment C of D.03-07-034 for all electric customers within the [CITY OR COUNTY].

1. Aggregate annual usage data (kWh) broken out by city, zip code and customer and rate classes, on a monthly basis.
2. Public Goods Charge customer payments by zip code and city. Quarterly or monthly aggregated participation data already tracked for Commission reports.
3. The proportional share in a CCA's territory or proposed territory as defined in the Commission's energy efficiency policy manual.

Please include the number of electric service accounts in 1 above and separate the information between customers currently receiving bundled utility service from SDG&E and customers currently served under direct access arrangements.

The [CITY OR COUNTY] understands that D.03-07-034 ordered that SDG&E "shall provide the information and data described in Attachment C to any city, county or CCA that requests it, as set forth in this order without charge." We also understand through this Decision that this information "should be provided…within one week of the request."

Please send this information in electronic form via e-mail to [E-MAIL ADDRESS]. If you have any questions regarding this request, please contact [NAME] at [TELEPHONE NUMBER]. The [CITY OR COUNTY OF NAME] thanks you for your assistance.

Sincerely,

[NAME]
[TITLE]
[DEPARTMENT]
[CITY OR COUNTY NAME]

Appendix D – CCA Functional Elements

The operations of a CCA program include all activities needed to procure electricity for end-use customers, schedule delivery of the electricity, conduct financial settlements for wholesale electricity purchases and sales, determine the costs charged to individual customers, and interface with SDG&E which would provide billing, metering, and customer services to CCA customers. These activities can be grouped into the broad categories described below.

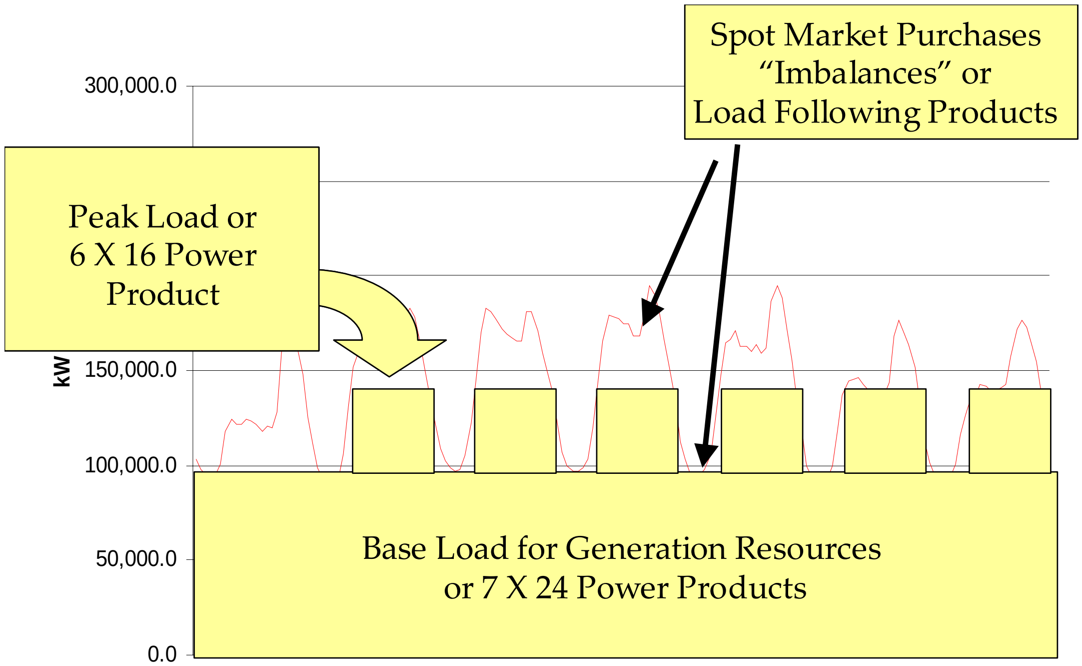
1. Portfolio Operations

Portfolio operations encompass the activities necessary for wholesale procurement of electricity to serve end-use customers. These activities are virtually identical to the supply functions performed by local utilities, municipal utilities, and energy service providers.

   a. Electricity Procurement

The essential purpose of the Aggregator is to assemble a portfolio of electricity supply sources on behalf of its customers. As an Aggregator, the County can choose from various types of resources and wholesale electricity products to achieve a supply portfolio that appropriately reflects the desired balance of cost certainty, environmental considerations, cost effectiveness, and operational and contractual flexibility.

A variety of generation resources or electricity purchase contracts can be employed to provide for the time-varying load requirements of the CCA program. The pattern of aggregate electricity usage typically follows daily, weekly and seasonal cycles, peaking during the afternoon hours and the summer months. The County must consider these load patterns when assembling a supply portfolio to properly match resources to the aggregate load shape of its customer base. Different types of generation resources and supply contracts supply the base load requirements, intermediate resource needs, and peaking load requirements. These concepts are illustrated in the following diagram.



A typical supply portfolio would utilize generation owned by the County or long-term contracts for the majority of projected base load requirements. These base load resources would be supplemented with intermediate resources or peak products as well as short-term contracts covering the additional seasonal load requirements of the portfolio, typically in the third quarter of each year. Spot market purchases and sales are used to fill the residual "net short" load requirements.

b. Risk And Credit Management

Risk management techniques would be employed to reduce the County's exposure to the volatility of energy markets and insulate customer rates from sudden changes in wholesale market prices. Credit monitoring is also important to keep abreast of changes in a supplier's financial condition and credit rating. Common practice in the energy industry is to periodically calculate the financial exposure to a supplier by comparing the value of the supply contract to the contractual price, utilizing so called "mark-to-market" valuation. Exposure to suppliers is greatest when the contractual price is low relative to prevailing market prices, and the risk of default becomes a concern. Collateral and other security instruments, such as letters of credits or surety bonds, are commonly used to manage credit risks between wholesale electricity buyers and sellers.

c. Load Forecasting

In performing the electricity procurement functions, it is necessary to 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.

The CCA will be required to purchase energy on the wholesale market for each hour of the day. To support financial settlements and energy procurement, an accurate record of total, time-of-day specific electricity demand and energy usage is essential. Lacking this, the CCA operator is required to rely on the distribution utility's recorded usage for each individual customer. All customer classes are not metered in the same way. In particular, residential and small commercial consumers (electric demand less the 20 kW) typically have simple electro-mechanical meters capable of metering only cumulative energy consumption. Medium commercial customers (electric demand in the range of 20 to 500 kW) are typically metered with energy and demand meters, but still lack time-of-day recording. Large commercial and industrial customers (electric demand greater than 500 kW) are typically equipped with data recording meters recording electric demand on five, ten or fifteen minute intervals (interval data recording meters or IDR).

Without a time-of-use record of energy consumed, the County will have to rely on prototypical rateclass load profiles. The California Independent System Operator (CAISO) allows use of load profiles that are approved by the local regulatory agency (CPUC) for scheduling and settlement. These load profiles are derived by distribution utility load research based on IDR metering of a stratified random sample from each rateclass (residential, small commercial, medium commercial, industrial). Hence, they represent the average or typical customer and not the CCA's actual customers. To date, the CPUC has approved the use of rateclass load profiles for use by the utilities and energy service providers for electricity scheduling and settlement. The local utilities have opposed proposals made in R.03-10-003 that Aggregators be allowed to use area-specific load profiles for these purposes.

CCAs have the option, under the law, to meter electricity supplied to the jurisdictional territories comprising the CCA to obtain an accurate record of aggregated loads. SDG&E is required to "install, maintain and calibrate metering devices at mutually agreeable locations within or adjacent to the CCA's political boundaries" at the request and at the expense of the CCA. SDG&E will also be required to "read the metering devices and provide the data collected to the CCA at the aggregator's expense."[30] Utilities are directed under CPUC Order Instituting Rulemaking R.03.09.007 (August 21, 2003) to develop specific tariff language to meet the requirements. Assessing the size, type, location, quantity and installation cost of such CCA wholesale metering will require an analysis of SDG&E's distribution system, in concert with utility Service Planners, and, will require SDG&E to comply with the CPUC's Order to develop applicable tariff terms and conditions. At this time, it is not clear to what extent the CPUC or the CAISO would have to approve the County's use of boundary meters for electricity scheduling and settlement.

d. Scheduling Coordination

Scheduling coordination costs are the costs associated with scheduling and settling electric supply transactions with the CAISO. All customer meters must be represented by a CAISO-certified scheduling coordinator. The scheduling coordinator submits schedules to the CAISO of hourly electric demands and supply resources on behalf of the County. The scheduling coordinator is responsible for costs associated with imbalances or deviations between the actual hourly loads and the actual hourly production of the resources it represents. It is also responsible for the costs of reserves and other services ("ancillary services") provided by the CAISO that are needed for reliable operation of the transmission system.

The County has several choices for obtaining services of a scheduling coordinator. Some companies act as independent scheduling coordinators and charge service fees for their services. Other companies such as power marketers or energy service providers will provide scheduling coordination services as part of a larger package of energy services, including wholesale electricity supply, load forecasting, and risk management. The charges for providing the scheduling coordinator services are bundled into the overall cost of electricity provided by the supplier. It is also possible for the County to become a CAISO certified scheduling coordinator, which requires acquisition of specialized software, completion of certification training conducted by the CAISO, and continuous staffing of a scheduling desk for 24 x 7 operations.

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[30] California Public Utilities Code §366.2(c)(18)

2. Rates

The County is responsible for setting its charges for the generation services it provides to CCA customers. The first step in setting rates is to determine the total dollars that must be collected from customers in order to cover all of the County's costs of doing business. This amount is known as the revenue requirement and consists of operating expenses, depreciation and amortization, interest and financing expenses, taxes, and reserve funds.

The revenue requirement is allocated to the various classes of customers in the CCA program, such as residential, small commercial, medium commercial, large industrial, agricultural, and street lighting customers. Revenue allocation is typically done on a cost of service basis, so that rates are reflective of differences in the County's costs of serving the different customer classes. The County may employ load research to estimate customer class load profiles and cost of service by use of sampling techniques, whereby load research meters that can record customer electricity consumption on a 5 to 15 minute interval basis are installed on a small sample of customers within each rate class. Alternatively, the County may utilize the customer class load profiles created by SDG&E.

Rate design is the process of setting the specific charges applicable to customer electricity usage. Rate schedules define the charges for each kWh, kW or other unit of electric service, and there may be one or more rate schedules applicable to each customer class. Rates are set so recover the County's revenue requirement on a forecast basis and are adjusted as needed to maintain sufficient revenues for the County.

3. Account Services

The County must be able to exchange customer meter usage data electronically with SDG&E using the utility's standard electronic data interchange procedures and formats. The County must receive and process customer payments collected by SDG&E. Aggregators may also need the capability to calculate individual customer bills and provide the amount to be collected to SDG&E in the formats and by the timelines required for inclusion in the bills sent by the local utilities. PG&E is the only local utility that offers "rate ready" billing service, whereby PG&E will calculate individual customer bills using the rates provided by the County. PG&E also offers "bill ready" billing service whereby the County calculates the amounts due from each customer and submits to PG&E for collections. SCE and SDG&E only offer "bill ready" billing.

The County must also be able to obtain customer meter data and process the data for submission to the CAISO through its scheduling coordinator so that the CAISO can complete its financial settlement process. Customer meter data must be processed in accordance with the CPUC's protocols for verification, estimation, and editing (VEE) of meter data. SDG&E will perform the VEE function for Aggregators as part of their metering service function. However, the County must apply load profiles to the usage data of customers whose consumption is measured on a cumulative monthly basis (e.g. residential and small commercial) in order to create the hourly usage data that must be submitted to the CAISO.

4. Administration

Administration and management of the CCA program includes finance, legal, regulatory, contract management and other program management functions. The scope of the administrative function depends on the complexity of the CCA implementation, which can range from a single contract with an energy services provider for operation of the program to the planning and staffing required for in-house operation and management of all aspects of the CCA program, with variations in between these two extremes. At a minimum, a senior level manager with experience in the electric utility industry should head the CCA program.

Appendix E – Base Case Pro Forma And Supporting Data

COUNTY OF SAN DIEGO
SUMMARY OF PRO FORMA RESULTS ($ MILLIONS)
$ -

Year	Commodity Costs	Ancillary Services and ISO Charges	Operations & Scheduling	Non-bypassable Charges	Metering & Billing	Financing Costs	Total Costs	SDG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	-	-	-	-	-	-	0.0	0%
2006	140.9	10.7	4.2	50.5	0.8	0.7	207.8	198.6	(9.2)	-2%
2007	145.8	11.3	4.2	47.8	0.9	0.7	210.6	204.7	(5.9)	-1%
2008	150.4	11.9	4.2	45.0	0.9	0.7	213.1	209.6	(3.5)	-1%
2009	156.7	13.0	4.2	41.6	1.0	12.4	228.8	227.6	(1.2)	0%
2010	164.6	13.9	4.2	34.8	1.0	9.6	228.0	237.9	9.9	2%
2011	174.0	15.0	4.2	13.5	1.0	9.5	217.2	232.6	15.4	3%
2012	171.8	15.7	4.2	13.8	1.1	17.1	223.7	247.2	23.5	5%
2013	185.0	16.4	4.2	14.0	1.1	16.9	237.7	257.1	19.4	4%
2014	191.5	17.1	4.2	14.3	1.2	16.7	245.0	266.9	21.9	4%
2015	189.2	17.8	4.2	14.6	1.3	20.5	247.7	278.9	31.2	6%
2016	195.7	18.5	4.2	15.2	1.3	20.2	255.2	287.8	32.6	6%
2017	221.4	19.6	4.2	15.2	1.4	19.9	281.8	305.8	24.0	4%
2018	238.0	21.2	4.2	15.5	1.4	19.7	300.1	336.2	36.1	6%
2019	255.2	22.9	4.2	15.8	1.5	19.4	319.0	364.3	45.3	7%
2020	265.7	23.8	4.3	16.1	1.6	19.0	330.5	379.5	49.1	7%
2021	278.8	24.3	4.3	16.4	1.6	18.6	344.0	384.7	40.7	6%
2022	287.3	25.1	4.3	16.8	1.7	18.1	353.3	396.3	43.0	6%
2023	301.9	26.4	4.3	-	1.8	17.7	352.1	402.0	49.8	7%
2024	321.0	28.1	4.3	-	1.9	17.3	372.6	431.0	58.5	8%
Total	4,035.0	352.9	80.2	400.8	24.4	274.9	5,168.2	5,648.6	480.4	5%

COUNTY OF SAN DIEGO
MONTHLY CUSTOMER BILL IMPACT ($/MONTH)
$ -

Year	Monthly Bill Impact Residential	Monthly Bill Impact Small Commercial	Monthly Bill Impact Medium Commercial	Monthly Bill Impact Medium Industrial	Monthly Bill Impact Large Industrial	Monthly Bill Impact Agricultural	Monthly Bill Impact Street Lighting
2005	0	0	0	0	0	0	0
2006	(2)	(6)	(122)	(730)	0	(7)	(4)
2007	(1)	(4)	(76)	(453)	0	(4)	(2)
2008	(1)	(2)	(46)	(273)	0	(3)	(1)
2009	(0)	(1)	(15)	(92)	0	(1)	(0)
2010	2	6	122	730	0	7	4
2011	3	9	186	1,111	0	11	6
2012	4	13	278	1,660	0	16	8
2013	3	10	224	1,341	0	13	7
2014	3	12	249	1,487	0	15	7
2015	5	16	346	2,071	0	20	10
2016	5	16	355	2,123	0	21	11
2017	4	12	256	1,530	0	15	8
2018	5	18	377	2,251	0	22	11
2019	6	22	463	2,769	0	27	14
2020	7	23	491	2,936	0	29	15
2021	6	19	399	2,386	0	23	12
2022	6	19	413	2,471	0	24	12
2023	7	22	468	2,801	0	28	14
2024	8	25	538	3,219	0	32	16
Total	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A

COUNTY OF SAN DIEGO
ELECTRIC SUPPLY RESOURCE MIX
$ -

CATEGORY	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Spot Market Purchases	0%	12%	13%	14%	13%	14%	14%	14%	13%	14%	14%	14%	11%	12%	14%	15%
Contract Purchases	0%	81%	78%	76%	25%	25%	24%	24%	25%	24%	24%	23%	26%	26%	25%	25%
Power Production - Natural Gas	0%	0%	0%	0%	51%	50%	48%	48%	47%	46%	45%	44%	43%	42%	41%	41%
Renewable Energy Purchases	0%	8%	9%	10%	11%	13%	14%	4%	6%	7%	3%	4%	6%	6%	7%	7%
Power Production - Renewable Energy	0%	0%	0%	0%	0%	0%	0%	10%	10%	10%	15%	15%	14%	14%	13%	13%
Off System Sales	0%	-1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%	0%	0%	0%
Total	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

COUNTY OF SAN DIEGO
ELECTRIC SUPPLY RESOURCE MIX
$ -

CATEGORY	2021	2022	2023	2024
Spot Market Purchases	15%	16%	17%	19%
Contract Purchases	25%	25%	24%	24%
Power Production - Natural Gas	40%	39%	38%	37%
Renewable Energy Purchases	7%	8%	8%	9%
Power Production - Renewable Energy	13%	12%	12%	11%
Off System Sales	0%	0%	0%	0%
Total	100%	100%	100%	100%

COUNTY OF SAN DIEGO
FINANCIAL PRO FORMA ANALYSIS
LOAD AGGREGATION SUMMARY
#

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012
I. SDG&E SDG&E'S UNBUNDLED GENERATION RATES ($/KWH)								
RESIDENTIAL (DR)	$0.06604	$0.06712	$0.06711	$0.06683	$0.07070	$0.07219	$0.06910	$0.07198
SMALL COMMERCIAL (A)	$0.08592	$0.08735	$0.08735	$0.08697	$0.09210	$0.09407	$0.08998	$0.09378
MEDIUM COMMERCIAL (AL-TOU)	$0.08478	$0.08619	$0.08618	$0.08582	$0.09087	$0.09281	$0.08878	$0.09253
MEDIUM INDUSTRIAL (AL-TOU)	$0.08478	$0.08619	$0.08618	$0.08582	$0.09087	$0.09281	$0.08878	$0.09253
LARGE INDUSTRIAL (AL-TOU)	$0.08478	$0.08619	$0.08618	$0.08582	$0.09087	$0.09281	$0.08878	$0.09253
AGRICULTURAL PUMPING	$0.08474	$0.08615	$0.08615	$0.08578	$0.09083	$0.09277	$0.08874	$0.09248
STREET LIGHTING AND TRAFFIC CONTROL	$0.07855	$0.07985	$0.07985	$0.07951	$0.08417	$0.08596	$0.08224	$0.08570
II. SDG&E SDG&E'S REVENUE REQUIREMENT FOR POWER SUPPLY ($)								
RESIDENTIAL (DR)	$0	$95,640,499	$98,584,879	$100,948,485	$109,564,703	$114,532,464	$112,019,670	$119,011,913
SMALL COMMERCIAL (A)	$0	$15,209,753	$15,677,984	$16,052,737	$17,438,939	$18,235,614	$17,823,113	$18,947,933
MEDIUM COMMERCIAL (AL-TOU)	$0	$62,767,885	$64,700,194	$66,246,938	$71,964,599	$75,251,103	$73,551,163	$78,190,722
MEDIUM INDUSTRIAL (AL-TOU)	$0	$9,015,917	$9,293,472	$9,515,645	$10,336,924	$10,808,994	$10,564,817	$11,231,238
LARGE INDUSTRIAL (AL-TOU)	$0	$0	$0	$0	$0	$0	$0	$0
AGRICULTURAL PUMPING	$0	$15,070,365	$15,534,306	$15,905,676	$17,278,444	$18,067,513	$17,659,382	$18,773,306
STREET LIGHTING AND TRAFFIC CONTROL	$0	$847,151	$873,230	$894,123	$971,055	$1,015,312	$992,561	$1,054,988
TOTAL - POWER SUPPLY REVENUE REQUIREMENT	$0	$198,551,570	$204,664,066	$209,563,605	$227,554,664	$237,911,000	$232,610,704	$247,210,099
AVERAGE RATE ($/KWH)	$0.00000	$0.07586	$0.0759	$0.0755	$0.0799	$0.0816	$0.0781	$0.0814
III. OPERATING EXPENSES ($)								
1. POWER SUPPLY COSTS:								
(A) ANCILLARY SERVICES AND RESERVES	$0	$8,173,206	$8,633,105	$9,058,995	$9,973,853	$10,747,698	$11,630,681	$12,198,049
(B) RENEWABLE PORTFOLIO STANDARD (RPS)	$0	$15,780,220	$18,572,604	$21,514,527	$24,599,457	$27,821,023	$31,173,097	$10,949,752
(C) DWR POWER	$0	$0	$0	$0	$0	$0	$0	$0
(D) POWER PRODUCTION	$0	$0	$0	$0	$65,521,664	$66,568,967	$68,273,010	$80,962,101
(E) CONTRACT PURCHASES	$0	$115,212,286	$115,212,286	$115,212,286	$51,391,999	$51,391,999	$51,391,999	$51,391,999
(F) MARKET PURCHASES	$0	$15,643,182	$18,168,653	$20,465,482	$21,572,476	$24,680,291	$28,028,893	$30,128,645
SUBTOTAL POWER SUPPLY COSTS	$0	$154,808,894	$160,586,647	$166,251,291	$173,059,449	$181,209,978	$190,497,679	$185,630,545
2. OTHER COSTS:								
(A) CALIFORNIA ISO COSTS	$0	$2,561,008	$2,705,795	$2,848,977	$3,028,288	$3,198,154	$3,376,635	$3,533,029
(B) NON-BYPASSABLE CHARGES	$0	$50,512,417	$47,754,389	$45,007,591	$41,578,206	$34,752,244	$13,489,176	$13,758,950
(C) START UP COSTS AMORTIZATION	$0	$5,528	$5,833	$6,153	$6,492	$6,849	$7,225	$7,623
(D) OPERATIONS & SCHEDULING COORDINATION	$0	$4,161,748	$4,169,821	$4,177,453	$4,184,649	$4,191,419	$4,197,774	$4,203,730
SUBTOTAL - OTHER COSTS	$0	$57,240,702	$54,635,838	$52,040,174	$48,797,634	$42,148,666	$21,070,811	$21,503,332

COUNTY OF SAN DIEGO
FINANCIAL PRO FORMA ANALYSIS
LOAD AGGREGATION SUMMARY
#

CATEGORY		[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012
3. UTILITY OPERATIONS:									
(A) DISTRIBUTION O&M		$0	$0	$0	$0	$0	$0	$0	$0
(B) CUSTOMER SERVICE		$0	$0	$0	$0	$0	$0	$0	$0
(C) METERING & BILLING		$0	$812,835	$858,853	$905,224	$951,919	$998,923	$1,046,227	$1,093,829
(D) ADMINISTRATIVE AND GENERAL		$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - UTILITY OPERATIONS		$0	$812,835	$858,853	$905,224	$951,919	$998,923	$1,046,227	$1,093,829
TOTAL OPERATING EXPENSES		$0	$212,862,431	$216,081,338	$219,196,689	$222,809,002	$224,357,567	$212,614,717	$208,227,707
IV. INTEREST EXPENSE ($)									
(A) INTEREST EXPENSE ($)		$0	$22,025	$21,721	$21,400	$8,831,131	$8,709,147	$8,580,454	$16,157,782
(B) DEBT COVERAGE		$0	$6,888	$0	$0	$2,755,365	$0	$0	$0
(C) WORKING CAPITAL EXPENSE		$0	$619,981	$655,958	$687,172	$776,973	$848,119	$914,235	$973,736
SUBTOTAL - FINANCING EXPENSE		$0	$648,894	$677,679	$708,572	$12,363,468	$9,557,266	$9,494,690	$17,131,517
V. REVENUES FROM MARKET SALES ($)									
(A) EXCESS ENERGY SALES		$0	$756,207	$520,274	$365,298	$497,084	$389,908	$294,990	$245,415
(B) EXCESS ANCILLARY SERVICE SALES		$0	$0	$0	$0	$0	$0	$0	$0
(C) SUPPLEMENTAL ENERGY PAYMENTS		$0	$4,973,133	$5,674,688	$6,456,789	$5,900,088	$5,517,546	$4,595,158	$1,395,584
SUBTOTAL - OTHER REVENUES		$0	$5,729,341	$6,194,962	$6,822,087	$6,397,172	$5,907,454	$4,890,148	$1,640,999
VI. REVENUE REQUIREMENT - NET MARKET SALES ($)		$0	$207,781,984	$210,564,056	$213,083,174	$228,775,299	$228,007,379	$217,219,259	$223,718,225
VII. CCA OPERATIONAL MARGIN		**$0**	**($9,230,414)**	**($5,899,990)**	**($3,519,569)**	**($1,220,635)**	**$9,903,621**	**$15,391,445**	**$23,491,874**
NET PRESENT VALUE OF OPERATIONAL MARGIN	$129,572,445.84								
NOMINAL MARGIN	$480,374,159.63								
DISCOUNT ON POWER SUPPLY REVENUE REQUIREMENTS	6%	0%	-5%	-3%	-2%	-1%	4%	7%	10%
DISCOUNT ON TOTAL REVENUE REQUIREMENTS	**3%**	**0%**	**-2%**	**-1%**	**-1%**	**0%**	**2%**	**3%**	**5%**
DEBT COVERAGE FUND ADDITION		$0	$6,888	$0	$0	$2,755,365	$0	$0	$0
NET VARIANCE		$0	($9,223,526)	($5,899,990)	($3,519,569)	$1,534,730	$9,903,621	$15,391,445	$23,491,874
NET VARIANCE (% OF GENERATION RATE)		0%	-5%	-3%	-2%	1%	4%	7%	10%
NET VARIANCE (% OF TOTAL RATE)		0%	-2%	-1%	-1%	0%	2%	3%	5%

COUNTY OF SAN DIEGO
FINANCIAL PRO FORMA ANALYSIS
LOAD AGGREGATION SUMMARY
#

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012
VIII. CCA POWER SUPPLY REVENUE REQUIREMENT ($/MWh)								
(A) MARKET PURCHASES	-	5.98	6.73	7.38	7.58	8.47	9.41	9.92
(B) CONTRACT PURCHASES	-	44.02	42.70	41.53	18.05	17.64	17.26	16.92
(C) POWER PRODUCTION	-	-	-	-	23.02	22.84	22.93	26.66
(D) RPS ENERGY	-	6.03	6.88	7.75	8.64	9.55	10.47	3.61
(E) DWR POWER	-	-	-	-	-	-	-	-
(F) ANCILLARY SERVICES & DEMAND RESERVES	-	3.12	3.20	3.27	3.50	3.69	3.91	4.02
(G) CALIFORNIA ISO COSTS	-	0.98	1.00	1.03	1.06	1.10	1.13	1.16
(H) NON-BYPASSABLE CHARGES	-	19.30	17.70	16.22	14.61	11.93	4.53	4.53
(I) FINANCING EXPENSE	-	0.25	0.25	0.26	4.35	3.28	3.19	5.64
(J) OPERATIONS & SCHEDULING COORDINATION	-	1.59	1.55	1.51	1.47	1.44	1.41	1.38
(K) METERING & BILLING	-	0.31	0.32	0.33	0.33	0.34	0.35	0.36
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SUBTOTAL - CCA REVENUE REQUIREMENT	-	81.57	80.33	79.26	82.62	80.27	74.59	74.20
IX. REVENUES FROM MARKET SALES, SEP ($/MWh)	-	2.19	2.30	2.46	2.25	2.03	1.64	0.54
X. CCA REVENUE REQUIREMENT - NET MARKET SALES ($/MWh)	-	79.38	78.04	76.80	80.37	78.24	72.95	73.66
VARIANCE SDG&E MINUS CCA ($/MWH)	**0.00**	**(3.53)**	**(2.19)**	**(1.27)**	**(0.43)**	**3.40**	**5.17**	**7.73**
Commodity Costs	-	53.83	54.02	54.20	55.05	56.47	58.43	56.56
Reserves/CAISO Costs	-	4.10	4.20	4.29	4.57	4.79	5.04	5.18
Non-bypassable Charges	-	19.30	17.70	16.22	14.61	11.93	4.53	4.53
Operations & Scheduling	-	1.59	1.55	1.51	1.47	1.44	1.41	1.38
Financing Expense	-	0.25	0.25	0.26	4.35	3.28	3.19	5.64
Metering & Billing	-	0.31	0.32	0.33	0.33	0.34	0.35	0.36
TOTAL	-	79.38	78.04	76.80	80.37	78.24	72.95	73.66
SDG&E Generation Rate	-	75.86	75.85	75.53	79.94	81.64	78.12	81.39
Breakeven Exit Fee	**-**	**15.77**	**15.51**	**14.95**	**14.18**	**15.32**	**9.70**	**12.26**

COUNTY OF SAN DIEGO
FINANCIAL PRO FORMA ANALYSIS
LOAD AGGREGATION SUMMARY
#

CATEGORY	[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018	[15] 2019	[16] 2020
I. SDG&E SDG&E'S UNBUNDLED GENERATION RATES ($/KWH)								
RESIDENTIAL (DR)	$0.07338	$0.07468	$0.07648	$0.07737	$0.08057	$0.08680	$0.09219	$0.09414
SMALL COMMERCIAL (A)	$0.09563	$0.09736	$0.09973	$0.10091	$0.10515	$0.11339	$0.12053	$0.12311
MEDIUM COMMERCIAL (AL-TOU)	$0.09435	$0.09605	$0.09840	$0.09956	$0.10374	$0.11186	$0.11890	$0.12145
MEDIUM INDUSTRIAL (AL-TOU)	$0.09435	$0.09605	$0.09840	$0.09956	$0.10374	$0.11186	$0.11890	$0.12145
LARGE INDUSTRIAL (AL-TOU)	$0.09435	$0.09605	$0.09840	$0.09956	$0.10374	$0.11186	$0.11890	$0.12145
AGRICULTURAL PUMPING	$0.09431	$0.09601	$0.09835	$0.09951	$0.10370	$0.11181	$0.11885	$0.12139
STREET LIGHTING AND TRAFFIC CONTROL	$0.08738	$0.08895	$0.09111	$0.09218	$0.09604	$0.10353	$0.11002	$0.11237
II. SDG&E SDG&E'S REVENUE REQUIREMENT FOR POWER SUPPLY ($)								
RESIDENTIAL (DR)	$123,753,646	$128,469,772	$134,193,628	$138,468,406	$147,092,696	$161,626,613	$175,103,271	$182,383,851
SMALL COMMERCIAL (A)	$19,708,737	$20,465,282	$21,384,653	$22,069,590	$23,457,702	$25,801,252	$27,973,717	$29,144,164
MEDIUM COMMERCIAL (AL-TOU)	$81,329,181	$84,450,100	$88,242,497	$91,068,163	$96,793,589	$106,459,052	$115,419,019	$120,246,914
MEDIUM INDUSTRIAL (AL-TOU)	$11,682,044	$12,130,329	$12,675,065	$13,080,941	$13,903,336	$15,291,673	$16,578,674	$17,272,148
LARGE INDUSTRIAL (AL-TOU)	$0	$0	$0	$0	$0	$0	$0	$0
AGRICULTURAL PUMPING	$19,526,829	$20,276,142	$21,186,670	$21,865,096	$23,239,727	$25,560,324	$27,711,539	$28,870,681
STREET LIGHTING AND TRAFFIC CONTROL	$1,097,246	$1,139,271	$1,190,320	$1,228,380	$1,305,408	$1,435,379	$1,555,873	$1,620,846
TOTAL - POWER SUPPLY REVENUE REQUIREMENT	$257,097,683	$266,930,895	$278,872,832	$287,780,576	$305,792,457	$336,174,293	$364,342,092	$379,538,604
AVERAGE RATE ($/KWH)	$0.0830	$0.0845	$0.0865	$0.0875	$0.0912	$0.0983	$0.1044	$0.1067
III. OPERATING EXPENSES ($)								
1. POWER SUPPLY COSTS:								
(A) ANCILLARY SERVICES AND RESERVES	$12,705,769	$13,205,995	$13,818,345	$14,283,298	$15,206,759	$16,568,708	$17,935,919	$18,681,592
(B) RENEWABLE PORTFOLIO STANDARD (RPS)	$14,371,100	$17,979,440	$7,312,826	$11,544,702	$16,920,317	$20,297,502	$23,892,997	$26,437,222
(C) DWR POWER	$0	$0	$0	$0	$0	$0	$0	$0
(D) POWER PRODUCTION	$82,562,129	$84,001,891	$89,111,147	$90,075,604	$93,989,037	$100,547,257	$106,840,911	$108,978,367
(E) CONTRACT PURCHASES	$60,868,420	$60,868,420	$60,868,420	$60,868,420	$84,939,331	$84,939,331	$84,939,331	$84,939,331
(F) MARKET PURCHASES	$29,287,429	$31,024,638	$32,948,034	$34,680,052	$28,857,871	$35,453,075	$42,854,616	$48,623,815
SUBTOTAL POWER SUPPLY COSTS	$199,794,847	$207,080,384	$204,058,772	$211,452,076	$239,913,314	$257,805,873	$276,463,773	$287,660,326
2. OTHER COSTS:								
(A) CALIFORNIA ISO COSTS	$3,690,364	$3,852,646	$4,028,771	$4,200,243	$4,411,126	$4,660,260	$4,916,632	$5,135,249
(B) NON-BYPASSABLE CHARGES	$14,034,129	$14,314,812	$14,601,108	$15,169,696	$15,190,993	$15,494,813	$15,804,709	$16,120,803
(C) START UP COSTS AMORTIZATION	$8,042	$8,484	$8,951	$9,443	$9,963	$10,511	$11,089	$11,699
(D) OPERATIONS & SCHEDULING COORDINATION	$4,209,804	$4,216,000	$4,222,320	$4,228,767	$4,235,342	$4,242,049	$4,248,890	$4,255,868
SUBTOTAL - OTHER COSTS	$21,942,339	$22,391,943	$22,861,150	$23,608,149	$23,847,424	$24,407,633	$24,981,319	$25,523,619

COUNTY OF SAN DIEGO
FINANCIAL PRO FORMA ANALYSIS
LOAD AGGREGATION SUMMARY
#

CATEGORY		[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018	[15] 2019	[16] 2020
3. UTILITY OPERATIONS:									
(A) DISTRIBUTION O&M		$0	$0	$0	$0	$0	$0	$0	$0
(B) CUSTOMER SERVICE		$0	$0	$0	$0	$0	$0	$0	$0
(C) METERING & BILLING		$1,143,599	$1,195,632	$1,250,034	$1,306,910	$1,366,375	$1,428,545	$1,493,543	$1,561,500
(D) ADMINISTRATIVE AND GENERAL		$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - UTILITY OPERATIONS		$1,143,599	$1,195,632	$1,250,034	$1,306,910	$1,366,375	$1,428,545	$1,493,543	$1,561,500
TOTAL OPERATING EXPENSES		$222,880,785	$230,667,959	$228,169,956	$236,367,136	$265,127,113	$283,642,050	$302,938,636	$314,745,445
IV. INTEREST EXPENSE ($)									
(A) INTEREST EXPENSE ($)		$15,908,061	$15,644,606	$19,438,508	$19,089,062	$18,720,397	$18,331,456	$17,921,123	$17,488,221
(B) DEBT COVERAGE		$0	$0	$0	$0	$0	$0	$0	$0
(C) WORKING CAPITAL EXPENSE		$1,014,177	$1,053,704	$1,102,088	$1,136,632	$1,216,791	$1,340,333	$1,455,101	$1,515,745
SUBTOTAL - FINANCING EXPENSE		$16,922,239	$16,698,310	$20,540,595	$20,225,695	$19,937,188	$19,671,789	$19,376,223	$19,003,966
V. REVENUES FROM MARKET SALES ($)									
(A) EXCESS ENERGY SALES		$338,998	$272,874	$229,282	$180,897	$1,428,425	$1,000,370	$686,796	$361,094
(B) EXCESS ANCILLARY SERVICE SALES		$0	$0	$0	$0	$0	$0	$0	$0
(C) SUPPLEMENTAL ENERGY PAYMENTS		$1,731,000	$2,080,509	$769,252	$1,240,749	$1,842,676	$2,217,915	$2,618,033	$2,903,528
SUBTOTAL - OTHER REVENUES		$2,069,997	$2,353,383	$998,534	$1,421,646	$3,271,101	$3,218,285	$3,304,830	$3,264,622
VI. REVENUE REQUIREMENT - NET MARKET SALES ($)		$237,733,026	$245,012,886	$247,712,017	$255,171,184	$281,793,200	$300,095,553	$319,010,030	$330,484,789
VII. CCA OPERATIONAL MARGIN		**$19,364,657**	**$21,918,009**	**$31,160,816**	**$32,609,392**	**$23,999,257**	**$36,078,740**	**$45,332,062**	**$49,053,815**
NET PRESENT VALUE OF OPERATIONAL MARGIN	$129,572,445.84								
NOMINAL MARGIN	$480,374,159.63								
DISCOUNT ON POWER SUPPLY REVENUE REQUIREMENTS	6%	8%	8%	11%	11%	8%	11%	12%	13%
DISCOUNT ON TOTAL REVENUE REQUIREMENTS	**3%**	**4%**	**4%**	**6%**	**6%**	**4%**	**6%**	**7%**	**7%**
DEBT COVERAGE FUND ADDITION		$0	$0	$0	$0	$0	$0	$0	$0
NET VARIANCE		$19,364,657	$21,918,009	$31,160,816	$32,609,392	$23,999,257	$36,078,740	$45,332,062	$49,053,815
NET VARIANCE (% OF GENERATION RATE)		8%	8%	11%	11%	8%	11%	12%	13%
NET VARIANCE (% OF TOTAL RATE)		4%	4%	6%	6%	4%	6%	7%	7%

COUNTY OF SAN DIEGO
FINANCIAL PRO FORMA ANALYSIS
LOAD AGGREGATION SUMMARY
#

CATEGORY	[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018	[15] 2019	[16] 2020
VIII. CCA POWER SUPPLY REVENUE REQUIREMENT ($/MWh)								
(A) MARKET PURCHASES	9.45	9.82	10.22	10.55	8.61	10.36	12.28	13.66
(B) CONTRACT PURCHASES	19.65	19.26	18.88	18.51	25.33	24.83	24.35	23.87
(C) POWER PRODUCTION	26.65	26.58	27.65	27.40	28.03	29.40	30.62	30.62
(D) RPS ENERGY	4.64	5.69	2.27	3.51	5.05	5.93	6.85	7.43
(E) DWR POWER	-	-	-	-	-	-	-	-
(F) ANCILLARY SERVICES & DEMAND RESERVES	4.10	4.18	4.29	4.34	4.53	4.84	5.14	5.25
(G) CALIFORNIA ISO COSTS	1.19	1.22	1.25	1.28	1.32	1.36	1.41	1.44
(H) NON-BYPASSABLE CHARGES	4.53	4.53	4.53	4.61	4.53	4.53	4.53	4.53
(I) FINANCING EXPENSE	5.46	5.29	6.38	6.15	5.95	5.75	5.56	5.34
(J) OPERATIONS & SCHEDULING COORDINATION	1.36	1.33	1.31	1.29	1.26	1.24	1.22	1.20
(K) METERING & BILLING	0.37	0.38	0.39	0.40	0.41	0.42	0.43	0.44
SUBTOTAL - CCA REVENUE REQUIREMENT	77.40	78.28	77.16	78.05	85.01	88.68	92.38	93.78
IX. REVENUES FROM MARKET SALES, SEP ($/MWh)	0.67	0.74	0.31	0.43	0.98	0.94	0.95	0.92
X. CCA REVENUE REQUIREMENT - NET MARKET SALES ($/MWh)	76.74	77.54	76.85	77.61	84.03	87.73	91.44	92.87
VARIANCE SDG&E MINUS CCA ($/MWH)	**6.25**	**6.94**	**9.67**	**9.92**	**7.16**	**10.55**	**12.99**	**13.78**
Commodity Costs	59.72	60.61	58.71	59.54	66.03	69.59	73.15	74.67
Reserves/CAISO Costs	5.29	5.40	5.54	5.62	5.85	6.21	6.55	6.69
Non-bypassable Charges	4.53	4.53	4.53	4.61	4.53	4.53	4.53	4.53
Operations & Scheduling	1.36	1.33	1.31	1.29	1.26	1.24	1.22	1.20
Financing Expense	5.46	5.29	6.38	6.15	5.95	5.75	5.56	5.34
Metering & Billing	0.37	0.38	0.39	0.40	0.41	0.42	0.43	0.44
TOTAL	76.74	77.54	76.85	77.61	84.03	87.73	91.44	92.87
SDG&E Generation Rate	82.99	84.47	86.52	87.53	91.19	98.28	104.43	106.65
Breakeven Exit Fee	**10.78**	**11.47**	**14.20**	**14.53**	**11.69**	**15.08**	**17.52**	**18.31**

CATEGORY	[17] 2021	[18] 2022	[19] 2023	[20] 2024
I. SDG&E SDG&E'S UNBUNDLED GENERATION RATES ($/KWH)				
RESIDENTIAL (DR)	$0.09355	$0.09447	$0.09340	$0.09819
SMALL COMMERCIAL (A)	$0.12233	$0.12355	$0.12359	$0.12994
MEDIUM COMMERCIAL (AL-TOU)	$0.12068	$0.12188	$0.12186	$0.12811
MEDIUM INDUSTRIAL (AL-TOU)	$0.12068	$0.12188	$0.12186	$0.12811
LARGE INDUSTRIAL (AL-TOU)	$0.12068	$0.12188	$0.12186	$0.12811
AGRICULTURAL PUMPING	$0.12062	$0.12182	$0.12180	$0.12805
STREET LIGHTING AND TRAFFIC CONTROL	$0.11166	$0.11277	$0.11240	$0.11817
II. SDG&E SDG&E'S REVENUE REQUIREMENT FOR POWER SUPPLY ($)				
RESIDENTIAL (DR)	$184,865,286	$190,421,017	$192,026,049	$205,914,747
SMALL COMMERCIAL (A)	$29,538,470	$30,429,740	$31,049,943	$33,295,697
MEDIUM COMMERCIAL (AL-TOU)	$121,874,202	$125,550,885	$128,043,020	$137,304,008
MEDIUM INDUSTRIAL (AL-TOU)	$17,505,890	$18,034,005	$18,391,973	$19,722,212
LARGE INDUSTRIAL (AL-TOU)	$0	$0	$0	$0
AGRICULTURAL PUMPING	$29,261,388	$30,144,136	$30,741,936	$32,965,413
STREET LIGHTING AND TRAFFIC CONTROL	$1,642,813	$1,692,321	$1,720,531	$1,844,973
TOTAL - POWER SUPPLY REVENUE REQUIREMENT	$384,688,049	$396,272,104	$401,973,453	$431,047,049
AVERAGE RATE ($/KWH)	$0.1060	$0.1070	$0.1064	$0.1119
III. OPERATING EXPENSES ($)				
1. POWER SUPPLY COSTS:				
(A) ANCILLARY SERVICES AND RESERVES	$18,954,710	$19,535,932	$20,616,126	$22,030,371
(B) RENEWABLE PORTFOLIO STANDARD (RPS)	$28,011,603	$30,185,520	$33,498,459	$37,694,993
(C) DWR POWER	$0	$0	$0	$0
(D) POWER PRODUCTION	$108,105,788	$109,066,448	$112,872,914	$118,409,233
(E) CONTRACT PURCHASES	$96,798,434	$96,798,434	$96,798,434	$96,798,434
(F) MARKET PURCHASES	$49,297,211	$54,709,046	$62,451,631	$72,217,853
SUBTOTAL POWER SUPPLY COSTS	$301,167,746	$310,295,379	$326,237,564	$347,150,884
2. OTHER COSTS:				
(A) CALIFORNIA ISO COSTS	$5,327,208	$5,549,270	$5,815,589	$6,114,617
(B) NON-BYPASSABLE CHARGES	$16,443,219	$16,772,084	$0	$0
(C) START UP COSTS AMORTIZATION	$12,342	$13,021	$13,737	$14,493
(D) OPERATIONS & SCHEDULING COORDINATION	$4,262,985	$4,270,245	$4,277,650	$4,285,203
SUBTOTAL - OTHER COSTS	$26,045,754	$26,604,620	$10,106,976	$10,414,312

CATEGORY		[17] 2021	[18] 2022	[19] 2023	[20] 2024
3. UTILITY OPERATIONS:					
(A) DISTRIBUTION O&M		$0	$0	$0	$0
(B) CUSTOMER SERVICE		$0	$0	$0	$0
(C) METERING & BILLING		$1,632,548	$1,706,829	$1,784,490	$1,865,684
(D) ADMINISTRATIVE AND GENERAL		$0	$0	$0	$0
SUBTOTAL - UTILITY OPERATIONS		$1,632,548	$1,706,829	$1,784,490	$1,865,684
TOTAL OPERATING EXPENSES		$328,846,048	$338,606,828	$338,129,030	$359,430,880
IV. INTEREST EXPENSE ($)					
(A) INTEREST EXPENSE ($)		$17,031,510	$16,549,679	$16,041,349	$15,505,059
(B) DEBT COVERAGE		$0	$0	$0	$0
(C) WORKING CAPITAL EXPENSE		$1,535,640	$1,581,692	$1,674,889	$1,796,029
SUBTOTAL - FINANCING EXPENSE		$18,567,150	$18,131,371	$17,716,238	$17,301,089
V. REVENUES FROM MARKET SALES ($)					
(A) EXCESS ENERGY SALES		$308,802	$106,035	$0	$0
(B) EXCESS ANCILLARY SERVICE SALES		$0	$0	$0	$0
(C) SUPPLEMENTAL ENERGY PAYMENTS		$3,082,488	$3,327,321	$3,697,911	$4,166,501
SUBTOTAL - OTHER REVENUES		$3,391,290	$3,433,356	$3,697,911	$4,166,501
VI. REVENUE REQUIREMENT - NET MARKET SALES ($)		$344,021,908	$353,304,843	$352,147,357	$372,565,468
VII. CCA OPERATIONAL MARGIN		**$40,666,142**	**$42,967,261**	**$49,826,096**	**$58,481,582**
NET PRESENT VALUE OF OPERATIONAL MARGIN	$129,572,445.84				
NOMINAL MARGIN	$480,374,159.63				
DISCOUNT ON POWER SUPPLY REVENUE REQUIREMENTS	6%	11%	11%	12%	14%
DISCOUNT ON TOTAL REVENUE REQUIREMENTS	**3%**	**6%**	**6%**	**7%**	**8%**
DEBT COVERAGE FUND ADDITION		$0	$0	$0	$0
NET VARIANCE		$40,666,142	$42,967,261	$49,826,096	$58,481,582
NET VARIANCE (% OF GENERATION RATE)		11%	11%	12%	14%
NET VARIANCE (% OF TOTAL RATE)		6%	6%	7%	8%

CATEGORY	[17] 2021	[18] 2022	[19] 2023	[20] 2024
VIII. CCA POWER SUPPLY REVENUE REQUIREMENT ($/MWh)				
(A) MARKET PURCHASES	13.58	14.78	16.54	18.75
(B) CONTRACT PURCHASES	26.67	26.14	25.63	25.13
(C) POWER PRODUCTION	29.78	29.46	29.89	30.74
(D) RPS ENERGY	7.72	8.15	8.87	9.79
(E) DWR POWER	-	-	-	-
(F) ANCILLARY SERVICES & DEMAND RESERVES	5.22	5.28	5.46	5.72
(G) CALIFORNIA ISO COSTS	1.47	1.50	1.54	1.59
(H) NON-BYPASSABLE CHARGES	4.53	4.53	-	-
(I) FINANCING EXPENSE	5.12	4.90	4.69	4.50
(J) OPERATIONS & SCHEDULING COORDINATION	1.17	1.15	1.13	1.11
(K) METERING & BILLING	0.45	0.46	0.47	0.48
SUBTOTAL - CCA REVENUE REQUIREMENT	95.71	96.35	94.23	97.80
IX. REVENUES FROM MARKET SALES, SEP ($/MWh)	0.93	0.93	0.98	1.08
X. CCA REVENUE REQUIREMENT - NET MARKET SALES ($/MWh)	94.78	95.42	93.25	96.72
VARIANCE SDG&E MINUS CCA ($/MWH)	**11.20**	**11.61**	**13.19**	**15.18**
Commodity Costs	76.81	77.60	79.95	83.32
Reserves/CAISO Costs	6.69	6.78	7.00	7.31
Non-bypassable Charges	4.53	4.53	-	-
Operations & Scheduling	1.17	1.15	1.13	1.11
Financing Expense	5.12	4.90	4.69	4.50
Metering & Billing	0.45	0.46	0.47	0.48
TOTAL	94.78	95.42	93.25	96.72
SDG&E Generation Rate	105.98	107.03	106.44	111.90
Breakeven Exit Fee	**15.73**	**16.14**	**13.19**	**15.18**

COUNTY OF SAN DIEGO
FINANCIAL PRO FORMA ANALYSIS
DEBT SERVICE
#

I. TOTAL DEBT ISSUANCES

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015	[12] 2016
(A) STARTUP COSTS	$0	$400,458	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(B) GENERATION DEVELOPMENT	$0	$0	$0	$0	$160,183,066	$0	$0	$140,238,141	$0	$0	$74,033,571	$0
SUBTOTAL - DEBT ISSUANCE	$0	$400,458	$0	$0	$160,183,066	$0	$0	$140,238,141	$0	$0	$74,033,571	$0

II. TOTAL DEBT SERVICE

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015	[12] 2016
(A) STARTUP COSTS	$0	$27,554	$27,554	$27,554	$27,554	$27,554	$27,554	$27,554	$27,554	$27,554	$27,554	$27,554
(B) GENERATION DEVELOPMENT	$0	$0	$0	$0	$11,021,458	$11,021,458	$11,021,458	$20,670,598	$20,670,598	$20,670,598	$25,764,507	$25,764,507
SUBTOTAL - FINANCING COSTS	$0	$27,554	$27,554	$27,554	$11,049,012	$11,049,012	$11,049,012	$20,698,152	$20,698,152	$20,698,152	$25,792,061	$25,792,061
(D) DEBT COVERAGE (1.25)	$0	$6,888	$0	$0	$2,755,365	$0	$0	$0	$0	$0	$0	$0
TOTAL DEBT SERVICE	$0	$34,442	$27,554	$27,554	$13,804,377	$11,049,012	$11,049,012	$20,698,152	$20,698,152	$20,698,152	$25,792,061	$25,792,061

III. INTEREST PORTION OF DEBT SERVICE

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015	[12] 2016
(A) STARTUP COSTS	$0	$22,025	$21,721	$21,400	$21,062	$20,705	$20,328	$19,931	$19,511	$19,069	$18,603	$18,110
(B) GENERATION DEVELOPMENT	$0	$0	$0	$0	$8,810,069	$8,688,442	$8,560,126	$16,137,851	$15,888,550	$15,625,537	$19,419,905	$19,070,952
SUBTOTAL - FINANCING COSTS	$0	$22,025	$21,721	$21,400	$8,831,131	$8,709,147	$8,580,454	$16,157,782	$15,908,061	$15,644,606	$19,438,508	$19,089,062
TOTAL INTEREST	$0	$22,025	$21,721	$21,400	$8,831,131	$8,709,147	$8,580,454	$16,157,782	$15,908,061	$15,644,606	$19,438,508	$19,089,062

IV. PRINCIPAL PORTION OF DEBT SERVICE

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015	[12] 2016
(A) STARTUP COSTS	$0	$5,528	$5,833	$6,153	$6,492	$6,849	$7,225	$7,623	$8,042	$8,484	$8,951	$9,443
(B) GENERATION DEVELOPMENT	$0	$0	$0	$0	$2,211,390	$2,333,016	$2,461,332	$4,532,747	$4,782,049	$5,045,061	$6,344,602	$6,693,555
SUBTOTAL - FINANCING COSTS	$0	$5,528	$5,833	$6,153	$2,217,881	$2,339,865	$2,468,557	$4,540,370	$4,790,091	$5,053,546	$6,353,553	$6,702,998
TOTAL PRINCIPAL	$0	$5,528	$5,833	$6,153	$2,217,881	$2,339,865	$2,468,557	$4,540,370	$4,790,091	$5,053,546	$6,353,553	$6,702,998

V. RESERVES

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015	[12] 2016
DEBT COVERAGE RESERVE ($ B.O.Y.)	$0	$0	$6,888	$6,888	$6,888	$2,762,253	$2,762,253	$2,762,253	$2,762,253	$2,762,253	$2,762,253	$2,762,253
DEBT SERVICE RESERVE ($)	$0	$40,046	$40,046	$40,046	$16,058,352	$16,058,352	$16,058,352	$30,082,166	$30,082,166	$30,082,166	$37,485,524	$37,485,524
TOTAL DEBT SERVICE RESERVES	$0	$40,046	$46,934	$46,934	$16,065,241	$18,820,605	$18,820,605	$32,844,419	$32,844,419	$32,844,419	$40,247,777	$40,247,777

COUNTY OF SAN DIEGO
FINANCIAL PRO FORMA ANALYSIS
DEBT SERVICE
#

I. TOTAL DEBT ISSUANCES

CATEGORY	[13] 2017	[14] 2018	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
(A) STARTUP COSTS	$0	$0	$0	$0	$0	$0	$0	$0
(B) GENERATION DEVELOPMENT	$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - DEBT ISSUANCE	$0	$0	$0	$0	$0	$0	$0	$0

II. TOTAL DEBT SERVICE

CATEGORY	[13] 2017	[14] 2018	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
(A) STARTUP COSTS	$27,554	$27,554	$27,554	$27,554	$27,554	$27,554	$27,554	$27,554
(B) GENERATION DEVELOPMENT	$25,764,507	$25,764,507	$25,764,507	$25,764,507	$25,764,507	$25,764,507	$25,764,507	$25,764,507
SUBTOTAL - FINANCING COSTS	$25,792,061	$25,792,061	$25,792,061	$25,792,061	$25,792,061	$25,792,061	$25,792,061	$25,792,061
(D) DEBT COVERAGE (1.25)	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL DEBT SERVICE	$25,792,061	$25,792,061	$25,792,061	$25,792,061	$25,792,061	$25,792,061	$25,792,061	$25,792,061

III. INTEREST PORTION OF DEBT SERVICE

CATEGORY	[13] 2017	[14] 2018	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
(A) STARTUP COSTS	$17,591	$17,043	$16,465	$15,855	$15,211	$14,533	$13,816	$13,061
(B) GENERATION DEVELOPMENT	$18,702,806	$18,314,413	$17,904,658	$17,472,366	$17,016,298	$16,535,147	$16,027,532	$15,491,998
SUBTOTAL - FINANCING COSTS	$18,720,397	$18,331,456	$17,921,123	$17,488,221	$17,031,510	$16,549,679	$16,041,349	$15,505,059
TOTAL INTEREST	$18,720,397	$18,331,456	$17,921,123	$17,488,221	$17,031,510	$16,549,679	$16,041,349	$15,505,059

IV. PRINCIPAL PORTION OF DEBT SERVICE

CATEGORY	[13] 2017	[14] 2018	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
(A) STARTUP COSTS	$9,963	$10,511	$11,089	$11,699	$12,342	$13,021	$13,737	$14,493
(B) GENERATION DEVELOPMENT	$7,061,700	$7,450,094	$7,859,849	$8,292,141	$8,748,209	$9,229,360	$9,736,975	$10,272,509
SUBTOTAL - FINANCING COSTS	$7,071,663	$7,460,605	$7,870,938	$8,303,840	$8,760,551	$9,242,381	$9,750,712	$10,287,001
TOTAL PRINCIPAL	$7,071,663	$7,460,605	$7,870,938	$8,303,840	$8,760,551	$9,242,381	$9,750,712	$10,287,001

V. RESERVES

CATEGORY	[13] 2017	[14] 2018	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
DEBT COVERAGE RESERVE ($ B.O.Y.)	$2,762,253	$2,762,253	$2,762,253	$2,762,253	$2,762,253	$2,762,253	$2,762,253	$2,762,253
DEBT SERVICE RESERVE ($)	$37,485,524	$37,485,524	$37,485,524	$37,485,524	$37,485,524	$37,485,524	$37,485,524	$37,485,524
TOTAL DEBT SERVICE RESERVES	$40,247,777	$40,247,777	$40,247,777	$40,247,777	$40,247,777	$40,247,777	$40,247,777	$40,247,777

COUNTY OF SAN DIEGO
FINANCIAL PRO FORMA ANALYSIS
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CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018
SECTION I - PROJECTED MARKET PRICES:														
(A) MARKET ENERGY ($/MWH):														
AVERAGE ENERGY PRICE	$48.74	$45.95	$47.08	$47.93	$52.67	$56.16	$60.39	$62.18	$63.39	$64.42	$66.11	$66.64	$70.15	$76.31
ON-PEAK ENERGY PRICE	$56.05	$52.85	$54.14	$55.12	$60.57	$64.58	$69.45	$71.51	$72.90	$74.09	$76.03	$76.64	$80.67	$87.76
OFF-PEAK ENERGY PRICE	$41.43	$39.06	$40.02	$40.74	$44.77	$47.73	$51.33	$52.85	$53.88	$54.76	$56.20	$56.65	$59.63	$64.87
REAL-TIME PREMIUM	$4.87	$4.60	$4.71	$4.79	$5.27	$5.62	$6.04	$6.22	$6.34	$6.44	$6.61	$6.66	$7.01	$7.63
(B) CDWR CONTRACT ENERGY ($/MWH):														
AVERAGE CDWR CONTRACT PRICE	$76.58	$75.76	$75.20	$80.33	$91.37	$89.73	$67.49	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
(C) RENEWABLE PORTFOLIO STANDARD (RPS):														
RPS REQUIREMENTS (%)	7.1%	8.2%	9.3%	10.4%	11.4%	12.5%	13.6%	14.6%	15.7%	16.8%	17.9%	18.9%	20.0%	20.0%
RPS ENERGY PRICE ($/MWH)	$66.90	$67.57	$68.25	$68.93	$69.62	$70.31	$71.02	$71.73	$72.44	$73.17	$74.63	$75.23	$79.18	$86.14
RPS CONTRACT CAPACITY (MW)	-	26	31	35	40	44	49	17	22	27	10	17	23	26
TOTAL RENEWABLE CAPACITY (MW)	-	26	31	35	40	44	49	54	59	65	71	76	82	84
(D) ANCILLARY SERVICE PRICES ($/MWH):														
SPINNING RESERVE	$11.02	$10.39	$10.64	$10.83	$11.90	$12.69	$13.65	$14.05	$14.33	$14.56	$14.94	$15.06	$15.85	$17.25
NON-SPINNING RESERVE	$6.87	$6.48	$6.64	$6.76	$7.43	$7.92	$8.51	$8.77	$8.94	$9.08	$9.32	$9.40	$9.89	$10.76
REPLACEMENT RESERVE	$10.09	$9.51	$9.75	$9.92	$10.90	$11.62	$12.50	$12.87	$13.12	$13.34	$13.69	$13.80	$14.52	$15.80
REGULATION - UP	$32.22	$30.37	$31.12	$31.68	$34.81	$37.12	$39.92	$41.10	$41.90	$42.58	$43.70	$44.05	$46.37	$50.44
REGULATION - DOWN	$32.22	$30.37	$31.12	$31.68	$34.81	$37.12	$39.92	$41.10	$41.90	$42.58	$43.70	$44.05	$46.37	$50.44
(E) NATURAL GAS PRICE ($/MMBtu):														
AVERAGE NATURAL GAS PRICE	$6.09	$5.57	$5.41	$5.33	$5.27	$5.35	$5.49	$5.65	$5.76	$5.86	$6.01	$6.06	$6.38	$6.94
REFEENCE GAS PRICE - HIGH	$7.62	$6.96	$6.76	$6.66	$6.58	$6.69	$6.86	$7.07	$7.20	$7.32	$7.51	$7.57	$7.97	$8.67
REFEENCE GAS PRICE - MID	$6.09	$5.57	$5.41	$5.33	$5.27	$5.35	$5.49	$5.65	$5.76	$5.86	$6.01	$6.06	$6.38	$6.94
REFEENCE GAS PRICE - LOW	$4.57	$4.18	$4.06	$3.99	$3.95	$4.01	$4.12	$4.24	$4.32	$4.39	$4.51	$4.54	$4.78	$5.20
(F) EMISSIONS CREDIT PRICE ($/LB):	$10.00	$10.25	$10.51	$10.77	$11.04	$11.31	$11.60	$11.89	$12.18	$12.49	$12.80	$13.12	$13.45	$13.79
(G) CAPACITY ($/MW):	$100,000	$102,500	$105,063	$107,689	$110,381	$113,141	$115,969	$118,869	$121,840	$124,886	$128,008	$131,209	$134,489	$137,851

CATEGORY	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
SECTION I - PROJECTED MARKET PRICES:						
(A) MARKET ENERGY ($/MWH):						
AVERAGE ENERGY PRICE	$82.18	$83.79	$82.30	$82.65	$85.86	$90.79
ON-PEAK ENERGY PRICE	$94.50	$96.36	$94.65	$95.05	$98.74	$104.41
OFF-PEAK ENERGY PRICE	$69.85	$71.22	$69.96	$70.25	$72.98	$77.17
REAL-TIME PREMIUM	$8.22	$8.38	$8.23	$8.27	$8.59	$9.08
(B) CDWR CONTRACT ENERGY ($/MWH):						
AVERAGE CDWR CONTRACT PRICE	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
(C) RENEWABLE PORTFOLIO STANDARD (RP						
RPS REQUIREMENTS (%)	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
RPS ENERGY PRICE ($/MWH)	$92.76	$94.57	$92.90	$93.29	$96.91	$102.48
RPS CONTRACT CAPACITY (MW)	28	31	33	36	38	41
TOTAL RENEWABLE CAPACITY (MW)	85	87	89	90	92	94
(D) ANCILLARY SERVICE PRICES ($/MWH):						
SPINNING RESERVE	$18.57	$18.94	$18.60	$18.68	$19.40	$20.52
NON-SPINNING RESERVE	$11.59	$11.81	$11.60	$11.65	$12.11	$12.80
REPLACEMENT RESERVE	$17.01	$17.34	$17.04	$17.11	$17.77	$18.79
REGULATION - UP	$54.32	$55.38	$54.40	$54.63	$56.75	$60.01
REGULATION - DOWN	$54.32	$55.38	$54.40	$54.63	$56.75	$60.01
(E) NATURAL GAS PRICE ($/MMBtu):						
AVERAGE NATURAL GAS PRICE	$7.47	$7.62	$7.48	$7.51	$7.81	$8.25
REFEENCE GAS PRICE - HIGH	$9.34	$9.52	$9.35	$9.39	$9.76	$10.32
REFEENCE GAS PRICE - MID	$7.47	$7.62	$7.48	$7.51	$7.81	$8.25
REFEENCE GAS PRICE - LOW	$5.60	$5.71	$5.61	$5.64	$5.85	$6.19
(F) EMISSIONS CREDIT PRICE ($/LB):	$14.13	$14.48	$14.85	$15.22	$15.60	$15.99
(G) CAPACITY ($/MW):	$141,297	$144,830	$148,451	$152,162	$155,966	$159,865

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018
SECTION II - PROJECTED LOADS AND ANCILLARY SERVICES:														
(A) PROJECTED LOADS (KWH):														
PROJECTED LOADS INCLUDING LOSSES														
ON-PEAK	0	1,745,858,843	1,799,707,778	1,850,610,304	1,898,608,138	1,943,763,710	1,986,156,189	2,025,877,911	2,066,395,469	2,107,723,379	2,149,877,846	2,192,875,403	2,236,732,911	2,281,467,570
OFF-PEAK	0	1,054,842,081	1,087,377,428	1,118,132,564	1,147,132,696	1,174,415,541	1,200,028,935	1,224,028,667	1,248,509,241	1,273,479,425	1,298,949,014	1,324,927,994	1,351,426,554	1,378,455,085
TOTAL	0	2,800,700,924	2,887,085,207	2,968,742,868	3,045,740,834	3,118,179,251	3,186,185,124	3,249,906,578	3,314,904,710	3,381,202,804	3,448,826,860	3,517,803,397	3,588,159,465	3,659,922,655
PROJECTED LOADS EXCLUDING LOSSES														
ON-PEAK	0	1,631,643,778	1,681,969,886	1,729,542,340	1,774,400,129	1,816,601,598	1,856,220,737	1,893,343,842	1,931,210,719	1,969,834,933	2,009,231,632	2,049,416,265	2,090,404,590	2,132,212,682
OFF-PEAK	0	985,833,721	1,016,240,587	1,044,983,705	1,072,086,631	1,097,584,618	1,121,522,369	1,143,952,025	1,166,831,066	1,190,167,687	1,213,971,041	1,238,250,462	1,263,015,471	1,288,275,780
TOTAL	0	2,617,477,499	2,698,210,474	2,774,526,045	2,846,486,761	2,914,186,216	2,977,743,106	3,037,295,868	3,098,041,785	3,160,002,621	3,223,202,673	3,287,666,727	3,353,420,061	3,420,488,462
(B) ANCILLARY SERVICES:														
ANCILLARY SERVICE REQUIREMENTS (KWH):														
SPINNING RESERVE	0	92,135,208	94,977,009	97,663,317	100,196,334	102,579,355	104,816,557	106,912,815	109,051,071	111,232,092	113,456,734	115,725,869	118,040,386	120,401,194
NON-SPINNING RESERVE	0	65,436,937	67,455,262	69,363,151	71,162,169	72,854,655	74,443,578	75,932,397	77,451,045	79,000,066	80,580,067	82,191,668	83,835,502	85,512,212
REPLACEMENT RESERVE	0	31,933,225	32,918,168	33,849,218	34,727,138	35,553,072	36,328,466	37,055,010	37,796,110	38,552,032	39,323,073	40,109,534	40,911,725	41,729,959
REGULATION - UP	0	58,893,244	60,709,736	62,426,836	64,045,952	65,569,190	66,999,220	68,339,157	69,705,940	71,100,059	72,522,060	73,972,501	75,451,951	76,960,990
REGULATION - DOWN	0	58,893,244	60,709,736	62,426,836	64,045,952	65,569,190	66,999,220	68,339,157	69,705,940	71,100,059	72,522,060	73,972,501	75,451,951	76,960,990
TOTAL - ANCILLARY SERVICES REQ.	0	307,291,858	316,769,910	325,729,358	334,177,546	342,125,462	349,587,041	356,578,535	363,710,106	370,984,308	378,403,994	385,972,074	393,691,515	401,565,345
ANCILLARY SERVICE COSTS ($)														
SPINNING RESERVE	$0	$971,337	$1,025,815	$1,073,887	$1,210,661	$1,321,600	$1,452,194	$1,525,210	$1,586,009	$1,644,010	$1,720,899	$1,769,420	$1,899,672	$2,107,941
NON-SPINNING RESERVE	$0	$430,405	$454,545	$475,846	$536,452	$585,610	$643,477	$675,831	$702,771	$728,471	$762,541	$784,041	$841,757	$934,042
REPLACEMENT RESERVE	$0	$308,353	$325,648	$340,908	$384,328	$419,546	$461,003	$484,182	$503,483	$521,895	$546,304	$561,707	$603,056	$669,172
REGULATION - UP	$0	$1,815,945	$1,917,793	$2,007,665	$2,263,370	$2,470,774	$2,714,924	$2,851,430	$2,965,094	$3,073,529	$3,217,276	$3,307,986	$3,551,497	$3,940,863
REGULATION - DOWN	$0	$1,815,945	$1,917,793	$2,007,665	$2,263,370	$2,470,774	$2,714,924	$2,851,430	$2,965,094	$3,073,529	$3,217,276	$3,307,986	$3,551,497	$3,940,863
TOTAL - ANCILLARY SERVICES COSTS	$0	$5,341,985	$5,641,594	$5,905,971	$6,658,181	$7,268,304	$7,986,521	$8,388,083	$8,722,449	$9,041,435	$9,464,296	$9,731,141	$10,447,478	$11,592,880
(C) PLANNING RESERVES:														
PLANNING RESERVES REQUIREMENTS (I	$0	$27,622	$28,474	$29,279	$30,038	$30,753	$31,423	$32,052	$32,693	$33,347	$34,014	$34,694	$35,388	$36,096
PLANNING RESERVES COSTS ($)	$0	$2,831,221	$2,991,510	$3,153,025	$3,315,672	$3,479,394	$3,644,160	$3,809,966	$3,983,320	$4,164,561	$4,354,048	$4,552,157	$4,759,281	$4,975,828

COUNTY OF SAN DIEGO
FINANCIAL PRO FORMA ANALYSIS
ANNUAL LOADS AND COMPOSITION OF RESOU

CATEGORY	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
SECTION II - PROJECTED LOADS AND ANCILLA						
(A) PROJECTED LOADS (KWH):						
PROJECTED LOADS INCLUDING LOSSES						
ON-PEAK	2,327,096,921	2,373,638,859	2,421,111,637	2,469,533,869	2,518,924,547	2,569,303,038
OFF-PEAK	1,406,024,187	1,434,144,671	1,462,827,564	1,492,084,115	1,521,925,798	1,552,364,313
TOTAL	3,733,121,108	3,807,783,530	3,883,939,201	3,961,617,985	4,040,850,344	4,121,667,351
PROJECTED LOADS EXCLUDING LOSSES						
ON-PEAK	2,174,856,936	2,218,354,074	2,262,721,156	2,307,975,579	2,354,135,090	2,401,217,792
OFF-PEAK	1,314,041,296	1,340,322,122	1,367,128,564	1,394,471,136	1,422,360,558	1,450,807,770
TOTAL	3,488,898,232	3,558,676,196	3,629,849,720	3,702,446,715	3,776,495,649	3,852,025,562
(B) ANCILLARY SERVICES:						
ANCILLARY SERVICE REQUIREMENTS (K						
SPINNING RESERVE	122,809,218	125,265,402	127,770,710	130,326,124	132,932,647	135,591,300
NON-SPINNING RESERVE	87,222,456	88,966,905	90,746,243	92,561,168	94,412,391	96,300,639
REPLACEMENT RESERVE	42,564,558	43,415,850	44,284,167	45,169,850	46,073,247	46,994,712
REGULATION - UP	78,500,210	80,070,214	81,671,619	83,305,051	84,971,152	86,670,575
REGULATION - DOWN	78,500,210	80,070,214	81,671,619	83,305,051	84,971,152	86,670,575
TOTAL - ANCILLARY SERVICES REQ.	409,596,652	417,788,585	426,144,357	434,667,244	443,360,589	452,227,801
ANCILLARY SERVICE COSTS ($)						
SPINNING RESERVE	$2,315,375	$2,407,922	$2,412,585	$2,471,224	$2,618,451	$2,824,180
NON-SPINNING RESERVE	$1,025,958	$1,066,966	$1,069,032	$1,095,015	$1,160,252	$1,251,412
REPLACEMENT RESERVE	$735,022	$764,401	$765,882	$784,497	$831,234	$896,544
REGULATION - UP	$4,328,668	$4,501,687	$4,510,405	$4,620,032	$4,895,277	$5,279,894
REGULATION - DOWN	$4,328,668	$4,501,687	$4,510,405	$4,620,032	$4,895,277	$5,279,894
TOTAL - ANCILLARY SERVICES COSTS	$12,733,691	$13,242,663	$13,268,310	$13,590,800	$14,400,490	$15,531,924
(C) PLANNING RESERVES:						
PLANNING RESERVES REQUIREMENTS (I	$36,818	$37,554	$38,305	$39,071	$39,853	$40,650
PLANNING RESERVES COSTS ($)	$5,202,228	$5,438,929	$5,686,401	$5,945,132	$6,215,635	$6,498,447

COUNTY OF SAN DIEGO
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CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018
SECTION III - PROJECTED RESOURCES:														
(A) RENEWABLE PORTFOLIO STANDARD (KWH):														
ON-PEAK	0	143,409,833	167,115,722	191,670,353	216,983,787	242,970,464	269,549,768	105,776,904	133,849,784	162,926,920	77,471,734	113,267,584	149,971,895	163,179,034
OFF-PEAK	0	86,647,742	100,970,761	115,806,587	131,100,879	146,801,943	162,861,070	40,445,953	57,407,493	74,975,802	12,899,633	31,333,289	54,055,451	62,558,879
TOTAL	0	230,057,576	268,086,483	307,476,940	348,084,667	389,772,406	432,410,838	146,222,858	191,257,277	237,902,722	90,371,367	144,600,873	204,027,347	225,737,913
COSTS ($):														
ON-PEAK	0	9,846,305	11,588,655	13,424,312	15,349,200	17,359,344	19,450,921	7,893,217	10,038,628	12,300,822	6,181,817	8,962,963	12,382,409	14,621,567
OFF-PEAK	0	5,933,915	6,983,950	8,090,216	9,250,257	10,461,679	11,722,176	3,056,535	4,332,472	5,678,619	1,131,009	2,581,739	4,537,908	5,675,935
TOTAL	0	15,780,220	18,572,604	21,514,527	24,599,457	27,821,023	31,173,097	10,949,752	14,371,100	17,979,440	7,312,826	11,544,702	16,920,317	20,297,502
(B) CDWR CONTRACT ENERGY (KWH):														
ON-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COSTS ($):														
ON-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BALANCE (KWH):														
ON-PEAK	0	1,602,449,009	1,632,592,056	1,658,939,951	1,681,624,351	1,700,793,246	1,716,606,420	1,920,101,007	1,932,545,685	1,944,796,459	2,072,406,112	2,079,607,819	2,086,761,016	2,118,288,536
OFF-PEAK	0	968,194,339	986,406,667	1,002,325,977	1,016,031,816	1,027,613,598	1,037,167,865	1,183,582,714	1,191,101,747	1,198,503,624	1,286,049,381	1,293,594,705	1,297,371,103	1,315,896,206
TOTAL	0	2,570,643,348	2,618,998,723	2,661,265,928	2,697,656,167	2,728,406,845	2,753,774,285	3,103,683,721	3,123,647,433	3,143,300,082	3,358,455,493	3,373,202,525	3,384,132,119	3,434,184,741
(C) POWER PRODUCTION (KWH):														
ON-PEAK	0	0	0	0	894,700,800	894,700,800	894,700,800	1,085,570,304	1,085,570,304	1,085,570,304	1,201,135,824	1,196,513,203	1,192,075,487	1,187,815,280
OFF-PEAK	0	0	0	0	650,563,200	650,563,200	650,563,200	789,350,016	789,350,016	789,350,016	873,381,096	870,019,853	866,793,059	863,695,338
TOTAL	0	0	0	0	1,545,264,000	1,545,264,000	1,545,264,000	1,874,920,320	1,874,920,320	1,874,920,320	2,074,516,920	2,066,533,056	2,058,868,547	2,051,510,617
COSTS ($):														
ON-PEAK	0	0	0	0	37,936,744	38,543,128	39,529,761	46,876,687	47,803,096	48,636,711	51,594,947	52,153,363	54,419,223	58,216,403
OFF-PEAK	0	0	0	0	27,584,920	28,025,839	28,743,249	34,085,414	34,759,033	35,365,180	37,516,200	37,922,241	39,569,814	42,330,854
TOTAL	0	0	0	0	65,521,664	66,568,967	68,273,010	80,962,101	82,562,129	84,001,891	89,111,147	90,075,604	93,989,037	100,547,257
BALANCE (KWH):														
ON-PEAK	0	1,602,449,009	1,632,592,056	1,658,939,951	786,923,551	806,092,446	821,905,620	834,530,703	846,975,381	859,226,155	871,270,288	883,094,616	894,685,529	930,473,256
OFF-PEAK	0	968,194,339	986,406,667	1,002,325,977	365,468,616	377,050,398	386,604,665	394,232,698	401,751,731	409,153,608	412,668,285	423,574,852	430,578,043	452,200,868
TOTAL	0	2,570,643,348	2,618,998,723	2,661,265,928	1,152,392,167	1,183,142,845	1,208,510,285	1,228,763,401	1,248,727,113	1,268,379,762	1,283,938,573	1,306,669,469	1,325,263,572	1,382,674,124

CATEGORY	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
SECTION III - PROJECTED RESOURCES:						
(A) RENEWABLE PORTFOLIO STANDARD (K'						
ON-PEAK	176,394,703	189,629,298	202,893,012	216,195,851	229,547,644	242,958,052
OFF-PEAK	71,046,513	79,525,470	88,002,714	96,485,064	104,979,198	113,491,667
TOTAL	247,441,216	269,154,768	290,895,727	312,680,915	334,526,842	356,449,719
COSTS ($):						
ON-PEAK	16,986,035	18,585,444	19,503,663	20,842,500	22,961,472	25,671,744
OFF-PEAK	6,906,963	7,851,778	8,507,940	9,343,021	10,536,987	12,023,249
TOTAL	23,892,997	26,437,222	28,011,603	30,185,520	33,498,459	37,694,993
						$106
(B) CDWR CONTRACT ENERGY (KWH):						
ON-PEAK	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0
COSTS ($):						
ON-PEAK	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0
BALANCE (KWH):						
ON-PEAK	2,150,702,218	2,184,009,561	2,218,218,624	2,253,338,018	2,289,376,903	2,326,344,985
OFF-PEAK	1,334,977,674	1,354,619,201	1,374,824,850	1,395,599,051	1,416,946,599	1,438,872,646
TOTAL	3,485,679,892	3,538,628,762	3,593,043,474	3,648,937,069	3,706,323,503	3,765,217,632
(C) POWER PRODUCTION (KWH):						
ON-PEAK	1,183,725,481	1,179,799,274	1,176,030,115	1,172,411,723	1,168,938,066	1,165,603,355
OFF-PEAK	860,721,525	857,866,664	855,125,998	852,494,959	849,969,161	847,544,396
TOTAL	2,044,447,006	2,037,665,938	2,031,156,113	2,024,906,682	2,018,907,227	2,013,147,751
COSTS ($):						
ON-PEAK	61,860,399	63,097,977	62,592,757	63,148,975	65,352,902	68,558,405
OFF-PEAK	44,980,511	45,880,390	45,513,030	45,917,472	47,520,012	49,850,828
TOTAL	106,840,911	108,978,367	108,105,788	109,066,448	112,872,914	118,409,233
BALANCE (KWH):						
ON-PEAK	966,976,737	1,004,210,288	1,042,188,509	1,080,926,295	1,120,438,837	1,160,741,630
OFF-PEAK	474,256,149	496,752,536	519,698,851	543,104,092	566,977,438	591,328,251
TOTAL	1,441,232,886	1,500,962,824	1,561,887,360	1,624,030,388	1,687,416,275	1,752,069,881

COUNTY OF SAN DIEGO
FINANCIAL PRO FORMA ANALYSIS
ANNUAL LOADS AND COMPOSITION OF RESOURCES

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018
(D) LONG-TERM CONTRACT PURCHASES (KWH):														
ON-PEAK	0	1,521,600,000	1,521,600,000	1,521,600,000	659,360,000	659,360,000	659,360,000	659,360,000	684,720,000	684,720,000	684,720,000	684,720,000	811,520,000	811,520,000
OFF-PEAK	0	737,600,000	737,600,000	737,600,000	110,640,000	110,640,000	110,640,000	110,640,000	129,080,000	129,080,000	129,080,000	129,080,000	129,080,000	129,080,000
TOTAL	0	2,259,200,000	2,259,200,000	2,259,200,000	770,000,000	770,000,000	770,000,000	770,000,000	813,800,000	813,800,000	813,800,000	813,800,000	940,600,000	940,600,000
COSTS ($):														
ON-PEAK	0	115,212,286	115,212,286	115,212,286	51,391,999	51,391,999	51,391,999	51,391,999	60,868,420	60,868,420	60,868,420	60,868,420	84,939,331	84,939,331
OFF-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	115,212,286	115,212,286	115,212,286	51,391,999	51,391,999	51,391,999	51,391,999	60,868,420	60,868,420	60,868,420	60,868,420	84,939,331	84,939,331
BALANCE (KWH):														
ON-PEAK	0	80,849,009	110,992,056	137,339,951	127,563,551	146,732,446	162,545,620	175,170,703	162,255,381	174,506,155	186,550,288	198,374,616	83,165,529	118,953,256
OFF-PEAK	0	230,594,339	248,806,667	264,725,977	254,828,616	266,410,398	275,964,665	283,592,698	272,671,731	280,073,608	283,588,285	294,494,852	301,498,043	323,120,868
TOTAL	0	311,443,348	359,798,723	402,065,928	382,392,167	413,142,845	438,510,285	458,763,401	434,927,113	454,579,762	470,138,573	492,869,469	384,663,572	442,074,124
(E) SHORT-TERM CONTRACT PURCHASES (KWH):														
ON-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COSTS ($):														
ON-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BALANCE (KWH):														
ON-PEAK	0	80,849,009	110,992,056	137,339,951	127,563,551	146,732,446	162,545,620	175,170,703	162,255,381	174,506,155	186,550,288	198,374,616	83,165,529	118,953,256
OFF-PEAK	0	230,594,339	248,806,667	264,725,977	254,828,616	266,410,398	275,964,665	283,592,698	272,671,731	280,073,608	283,588,285	294,494,852	301,498,043	323,120,868
TOTAL	0	311,443,348	359,798,723	402,065,928	382,392,167	413,142,845	438,510,285	458,763,401	434,927,113	454,579,762	470,138,573	492,869,469	384,663,572	442,074,124

CATEGORY	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
(D) LONG-TERM CONTRACT PURCHASES (KV						
ON-PEAK	811,520,000	811,520,000	836,880,000	836,880,000	836,880,000	836,880,000
OFF-PEAK	129,080,000	129,080,000	147,520,000	147,520,000	147,520,000	147,520,000
TOTAL	940,600,000	940,600,000	984,400,000	984,400,000	984,400,000	984,400,000
COSTS ($):						
ON-PEAK	84,939,331	84,939,331	96,798,434	96,798,434	96,798,434	96,798,434
OFF-PEAK	0	0	0	0	0	0
TOTAL	84,939,331	84,939,331	96,798,434	96,798,434	96,798,434	96,798,434
BALANCE (KWH):						
ON-PEAK	155,456,737	192,690,288	205,308,509	244,046,295	283,558,837	323,861,630
OFF-PEAK	345,176,149	367,672,536	372,178,851	395,584,092	419,457,438	443,808,251
TOTAL	500,632,886	560,362,824	577,487,360	639,630,388	703,016,275	767,669,881
(E) SHORT-TERM CONTRACT PURCHASES (K						
ON-PEAK	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0
COSTS ($):						
ON-PEAK	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0
BALANCE (KWH):						
ON-PEAK	155,456,737	192,690,288	205,308,509	244,046,295	283,558,837	323,861,630
OFF-PEAK	345,176,149	367,672,536	372,178,851	395,584,092	419,457,438	443,808,251
TOTAL	500,632,886	560,362,824	577,487,360	639,630,388	703,016,275	767,669,881

Appendix F – Pro Forma Summary With Alternative Supply Portfolios

Alternative Scenario 1

Year	Commodity Costs	Ancillary Services and ISO Charges	Operations & Scheduling	Non-bypassable Charges	Metering & Billing	Financing Costs	Total Costs	SDG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	-	-	-	-	-	-	0.0	0%
2006	144.4	10.7	4.2	50.5	0.8	0.7	211.3	198.6	(12.7)	-3%
2007	149.2	11.3	4.2	47.8	0.9	0.7	214.0	204.7	(9.4)	-2%
2008	153.9	11.9	4.2	45.0	0.9	0.7	216.6	209.6	(7.0)	-2%
2009	161.5	13.0	4.2	41.6	1.0	0.8	222.0	227.6	5.5	1%
2010	200.7	13.9	4.2	34.8	1.0	0.9	255.5	237.9	(17.6)	-4%
2011	208.3	15.0	4.2	13.5	1.0	0.9	243.0	232.6	(10.4)	-2%
2012	214.0	15.7	4.2	13.8	1.1	1.0	249.7	247.2	(2.5)	-1%
2013	219.3	16.4	4.2	14.0	1.1	1.0	256.1	257.1	1.0	0%
2014	224.7	17.1	4.2	14.3	1.2	1.1	262.6	266.9	4.3	1%
2015	260.3	17.8	4.2	14.6	1.3	1.1	299.3	278.9	(20.5)	-4%
2016	265.5	18.5	4.2	15.2	1.3	1.2	305.9	287.8	(18.1)	-3%
2017	274.3	19.6	4.2	15.2	1.4	1.2	316.0	305.8	(10.2)	-2%
2018	287.0	21.2	4.2	15.5	1.4	1.4	330.8	336.2	5.4	1%
2019	300.4	22.9	4.2	15.8	1.5	1.5	346.3	364.3	18.1	3%
2020	344.6	23.8	4.3	16.1	1.6	1.6	391.9	379.5	(12.3)	-2%
2021	349.5	24.3	4.3	16.4	1.6	1.6	397.7	384.7	(13.0)	-2%
2022	356.6	25.1	4.3	16.8	1.7	1.6	406.1	396.3	(9.8)	-1%
2023	367.8	26.4	4.3	-	1.8	1.7	402.0	402.0	0.0	0%
2024	382.0	28.1	4.3	-	1.9	1.8	418.1	431.0	12.9	2%
Total	4,864.0	352.9	80.2	400.8	24.4	22.5	5,744.9	5,648.6	(96.3)	-1%

Alternative Scenario 2

Year	Commodity Costs	Ancillary Services and ISO Charges	Operations & Scheduling	Non-bypassable Charges	Metering & Billing	Financing Costs	Total Costs	SDG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	-	-	-	-	-	-	0.0	0%
2006	148.0	10.7	4.2	50.5	0.8	0.7	214.8	198.6	(16.3)	-4%
2007	153.8	11.3	4.2	47.8	0.9	0.7	218.6	204.7	(13.9)	-3%
2008	159.3	11.9	4.2	45.0	0.9	0.7	222.0	209.6	(12.5)	-3%
2009	167.6	13.0	4.2	41.6	1.0	0.8	228.1	227.6	(0.6)	0%
2010	203.0	13.9	4.2	34.8	1.0	0.9	257.7	237.9	(19.8)	-4%
2011	211.0	15.0	4.2	13.5	1.0	0.9	245.7	232.6	(13.1)	-3%
2012	217.2	15.7	4.2	13.8	1.1	1.0	252.9	247.2	(5.7)	-1%
2013	223.0	16.4	4.2	14.0	1.1	1.0	259.8	257.1	(2.7)	-1%
2014	228.9	17.1	4.2	14.3	1.2	1.1	266.8	266.9	0.1	0%
2015	258.0	17.8	4.2	14.6	1.3	1.1	297.1	278.9	(18.2)	-3%
2016	264.0	18.5	4.2	15.2	1.3	1.2	304.4	287.8	(16.6)	-3%
2017	275.9	19.6	4.2	15.2	1.4	1.2	317.6	305.8	(11.8)	-2%
2018	293.8	21.2	4.2	15.5	1.4	1.4	337.5	336.2	(1.3)	0%
2019	312.0	22.9	4.2	15.8	1.5	1.5	357.9	364.3	6.4	1%
2020	347.5	23.8	4.3	16.1	1.6	1.5	394.8	379.5	(15.3)	-2%
2021	351.3	24.3	4.3	16.4	1.6	1.6	399.5	384.7	(14.8)	-2%
2022	358.8	25.1	4.3	16.8	1.7	1.6	408.3	396.3	(12.0)	-2%
2023	372.8	26.4	4.3	-	1.8	1.7	407.0	402.0	(5.1)	-1%
2024	391.5	28.1	4.3	-	1.9	1.8	427.6	431.0	3.4	0%
Total	4,937.5	352.9	80.2	400.8	24.4	22.4	5,818.2	5,648.6	(169.7)	-2%

Alternative Scenario 3

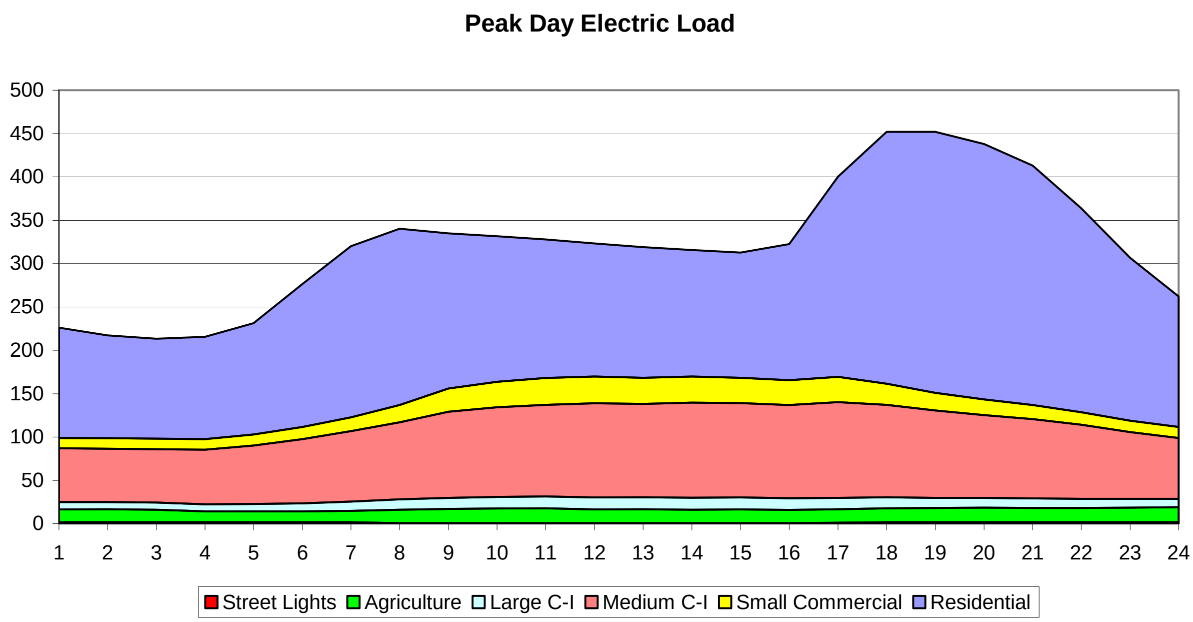
Year	Commodity Costs	Ancillary Services and ISO Charges	Operations & Scheduling	Non-bypassable Charges	Metering & Billing	Financing Costs	Total Costs	SDG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	-	-	-	-	-	-	0.0	0%
2006	144.0	10.7	4.2	50.5	0.8	0.7	210.9	198.6	(12.4)	-3%
2007	149.8	11.3	4.2	47.8	0.9	0.7	214.6	204.7	(9.9)	-2%
2008	117.2	11.9	4.2	45.0	0.9	42.2	221.4	209.6	(11.9)	-3%
2009	123.9	13.0	4.2	41.6	1.0	32.0	215.6	227.6	11.9	3%
2010	138.3	13.9	4.2	34.8	1.0	31.6	223.8	237.9	14.1	3%
2011	147.2	15.0	4.2	13.5	1.0	31.2	212.2	232.6	20.5	5%
2012	155.1	15.7	4.2	13.8	1.1	30.7	220.6	247.2	26.6	6%
2013	162.5	16.4	4.2	14.0	1.1	30.2	228.5	257.1	28.6	6%
2014	169.6	17.1	4.2	14.3	1.2	29.7	236.1	266.9	30.8	6%
2015	186.0	17.8	4.2	14.6	1.3	29.2	253.1	278.9	25.8	5%
2016	192.9	18.5	4.2	15.2	1.3	28.6	260.6	287.8	27.2	5%
2017	204.5	19.6	4.2	15.2	1.4	28.0	272.9	305.8	32.9	6%
2018	221.4	21.2	4.2	15.5	1.4	27.4	291.1	336.2	45.0	7%
2019	238.9	22.9	4.2	15.8	1.5	26.7	310.0	364.3	54.3	8%
2020	260.6	23.8	4.3	16.1	1.6	26.0	332.4	379.5	47.2	7%
2021	266.6	24.3	4.3	16.4	1.6	25.2	338.5	384.7	46.2	7%
2022	275.8	25.1	4.3	16.8	1.7	24.4	348.1	396.3	48.2	7%
2023	290.7	26.4	4.3	-	1.8	23.5	346.8	402.0	55.2	8%
2024	309.8	28.1	4.3	-	1.9	22.7	366.8	431.0	64.2	8%
Total	3,754.9	352.9	80.2	400.8	24.4	490.7	5,103.9	5,648.6	544.6	5%

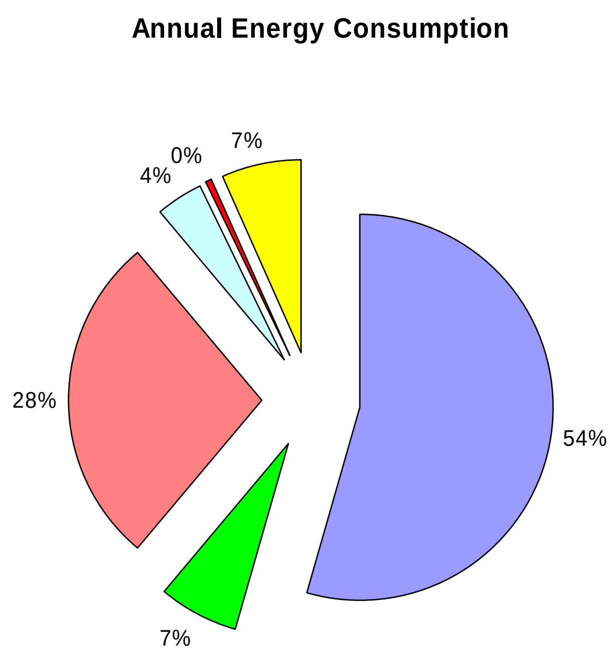
Alternative Scenario 4

Year	Commodity Costs	Ancillary Services and ISO Charges	Operations & Scheduling	Non-bypassable Charges	Metering & Billing	Financing Costs	Total Costs	SDG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	-	-	-	-	-	-	0.0	0%
2006	139.8	10.7	4.2	50.5	0.8	0.7	206.6	198.6	(8.1)	-2%
2007	144.6	11.3	4.2	47.8	0.9	0.7	209.4	204.7	(4.7)	-1%
2008	122.9	11.9	4.2	45.0	0.9	32.3	217.2	209.6	(7.6)	-2%
2009	129.6	13.0	4.2	41.6	1.0	24.5	213.9	227.6	13.6	3%
2010	142.8	13.9	4.2	34.8	1.0	24.3	220.9	237.9	17.0	4%
2011	150.4	15.0	4.2	13.5	1.0	24.0	208.1	232.6	24.5	6%
2012	158.0	15.7	4.2	13.8	1.1	23.6	216.5	247.2	30.7	7%
2013	165.1	16.4	4.2	14.0	1.1	23.3	224.2	257.1	32.9	7%
2014	172.0	17.1	4.2	14.3	1.2	22.9	231.7	266.9	35.2	7%
2015	188.4	17.8	4.2	14.6	1.3	22.5	248.8	278.9	30.0	6%
2016	195.0	18.5	4.2	15.2	1.3	22.0	256.2	287.8	31.6	6%
2017	206.8	19.6	4.2	15.2	1.4	21.6	268.8	305.8	37.0	6%
2018	224.3	21.2	4.2	15.5	1.4	21.2	287.8	336.2	48.3	8%
2019	242.3	22.9	4.2	15.8	1.5	20.7	307.4	364.3	56.9	9%
2020	263.7	23.8	4.3	16.1	1.6	20.2	329.6	379.5	49.9	7%
2021	268.8	24.3	4.3	16.4	1.6	19.6	334.9	384.7	49.7	7%
2022	277.4	25.1	4.3	16.8	1.7	18.9	344.2	396.3	52.1	7%
2023	292.2	26.4	4.3	-	1.8	18.3	343.0	402.0	59.0	8%
2024	311.4	28.1	4.3	-	1.9	17.7	363.4	431.0	67.6	9%
Total	3,795.4	352.9	80.2	400.8	24.4	379.0	5,032.7	5,648.6	615.8	6%

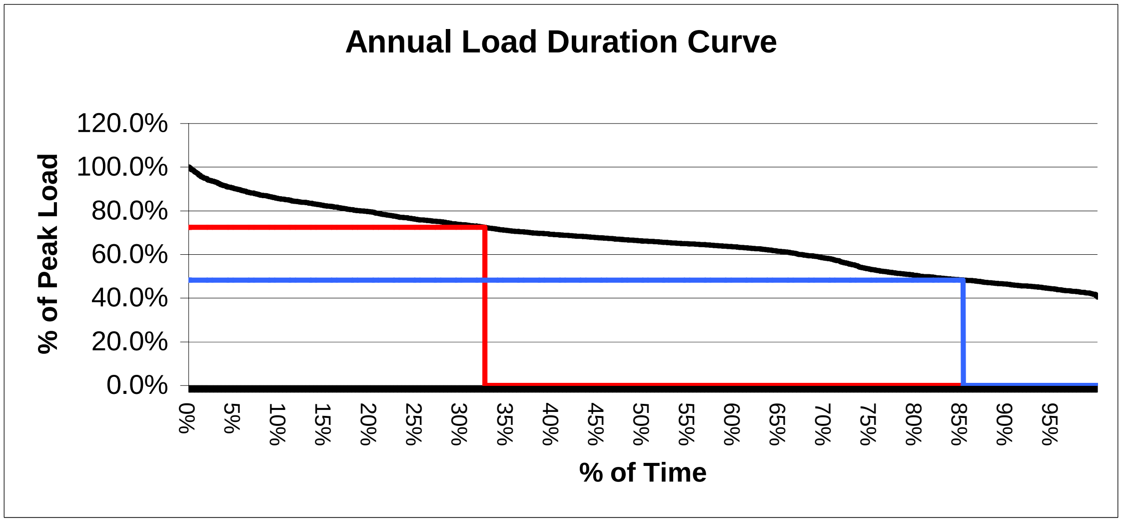
Appendix G – Electric Customers and Load Analysis

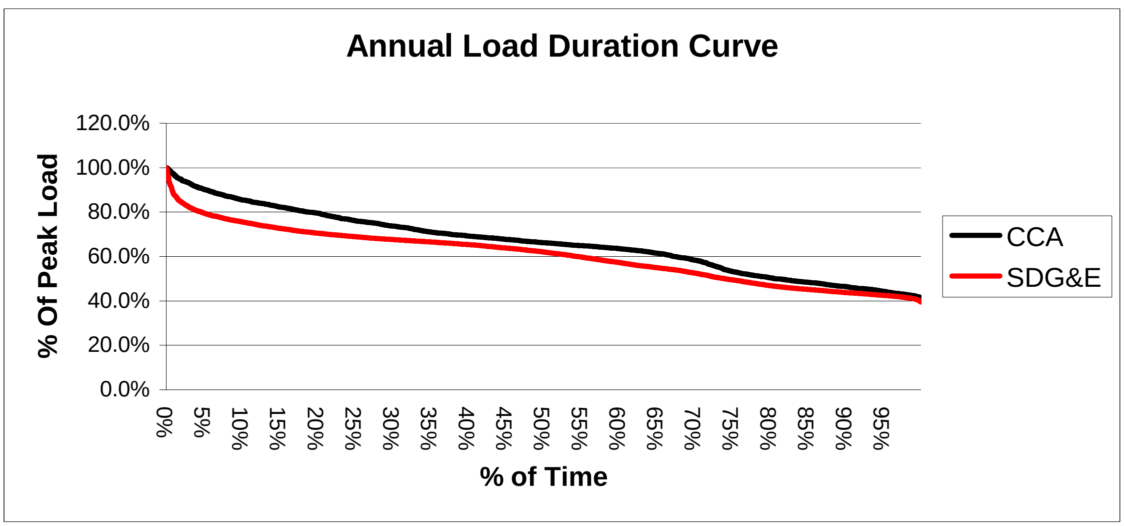
San Diego County CCA
Electric Demand and Energy Consumption



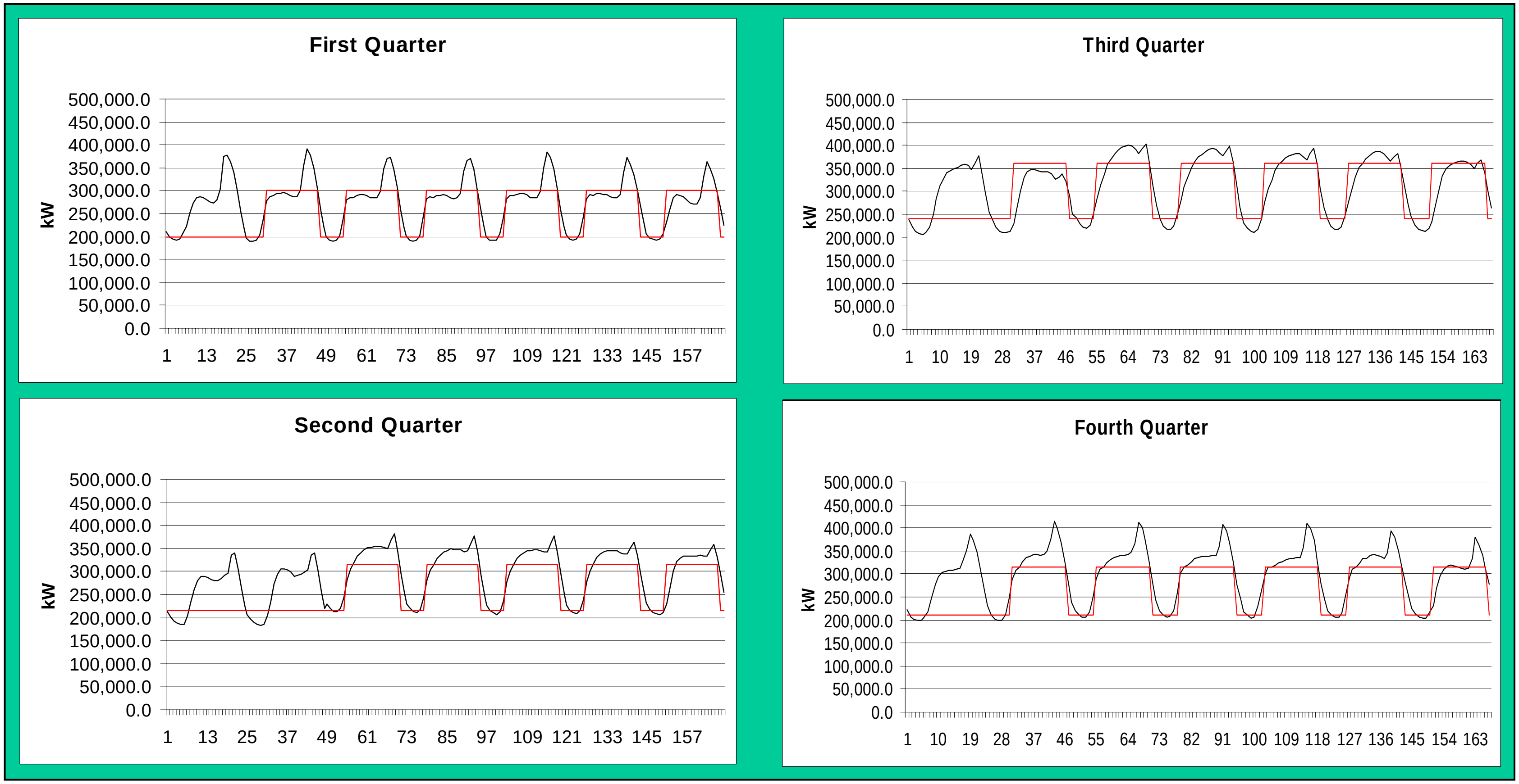


CCA Load Characteristics Compared to SDG&E System-Wide





San Diego County CCA Load Plots and Power Blocks



Quarter	7X24	6X16	Dumped kWh	Req. kWh	Qtr % kWk
1	200000	100000	9,140,300	604,736,164	1.51%
2	215000	100000	19,684,654	616,296,685	3.19%
3	240000	120000	20,376,170	726,926,202	2.80%
4	210000	105000	4,021,273	669,518,448	0.60%
			53,222,396	2,617,477,499	1.99%

Energy Purchases (kWh)

7X24	1,895,160,000	71.0%
6X16	520,640,000	19.5%
Spot On-Peak	106,879,626	4.0%
Spot Off-Peak	148,020,270	5.5%
Total	2,670,699,895	100.0%

Total Energy	Spot Purchases
2,617,477,499	9.5%

Appendix H – Implementation Schedule

In order to begin providing electric service to customers in the community in early 2006, the County would need to follow an aggressive timeline for decision-making and implementation activities. A timeline that would allow for operations to begin in May 2006 is shown below. A key decision on the critical path is the decision to develop the Implementation Plan. Delays in the decision to develop an Implementation Plan would cause one-for-one delays in the program start date.

COMMUNITY CHOICE AGGREGATION IMPLEMENTATION PROCESS AND TIMELINE

TASK	ESTIMATED START DATE
1 Feasibility Assessment and Evaluation	**6/1/05 – 7/7/05**
1.1 Review Final Feasibility Report	6/1/05
1.2 Conduct Public Workshop(s) and council sessions to consider proceeding to implementation	6/21/05
1.3 Decision to Develop CCA Implementation Plan	7/7/05
2 Implementation Plan Development	**7/14/05 – 10/30/05**
2.1 Obtain Billing Data From Utility	7/14/05
2.2 Issue Request For Qualifications/Offers To Suppliers	8/4/05
2.3 Identify uncommitted generation projects and negotiate participation, if applicable	8/4/05
2.4 Develop program structure, organization, operations plans and funding	8/11/06
2.5 Document participant rights and responsibilities	8/11/05
2.6 Select Preferred electric supplier(s) and partners; Evaluate and document their financial, technical and operational capabilities	8/25/05
2.7 Develop preliminary energy supply resource portfolio	8/25/05
2.8 Perform Rate Design (cost allocation methodology and disclosure)	9/2/05

TASK	ESTIMATED START DATE
2.9 Complete Draft Implementation Plan	9/9/05
2.10 Conduct Public Workshop(s) on Draft Implementation Plan	9/16/05
2.11 Issue Resolution Adopting Implementation Plan	9/30/05
3 CPUC Implementation Plan Filing	**10/6/05 – 1/5/06**
3.1 File Implementation Plan and Statement of Intent with CPUC	10/6/05
3.2 Respond to information requests from CPUC or intervenors	10/13/05
3.3 Participate as required in CPUC process to support implementation plan	10/13/05
3.4 Monitor CPUC decisions	1/5/06
4 Initiate CCA Startup Activities	**10/13/05 –2/10/06**
4.1 Conduct Recruiting and Staffing	
4.2 Develop informational and program marketing materials	10/13/05
4.3 Establish call center for customer inquiries	10/20/05
4.4 Develop in house capabilities or execute contracts for performance of operational services:	10/20/05
- Electronic data interchange with utility	-
- Customer bill calculations	-
- Scheduling coordinator services	-
- Application of statistical load profiles and submittal of hourly usage data for CAISO settlements	-
- Resource planning, portfolio and risk management	-
- Ratemaking	-
- Load forecasting	-
- Wholesale settlements	-
- Credit and finance	-
- Information Technology	-

TASK	ESTIMATED START DATE
- Legal and regulatory support	-
4.5 Contact key customers to explain program, obtain commitment, and release customer information	10/27/05
4.6 Execute contracts for electric supply	1/12/06
4.7 Update program rates	1/12/06
4.8 Obtain financing for program capital requirements	1/12/06
4.9 Execute service agreement with utility[31]	1/19/06
4.10 Complete utility technical testing	1/26/06
4.11 Establish account with utility	2/3/06
4.12 Register with CPUC, post bond or demonstrate insurance	2/10/06
5 Customer Notification and Enrollment	**2/17/06 – 4/19/06**
5.1 Send first opt-out notice to eligible and ineligible customers	2/17/06
5.2 Send second opt-out notice to eligible and ineligible customers	3/21/06
5.3 Process customer opt-out requests and enroll customers	3/28/06
5.4 Submit notification certification to CPUC	4/5/06
5.5 Notify utility when CCA service will begin to initiate account transfer	4/5/06
5.6 Obtain updated billing data from utility	4/12/06
5.7 Update load forecasts and supply plan	4/19/06
6 CCA Operations	**5/2/06 – Ongoing**
6.1 Activate energy supply resource plan	4/2/06
6.2 Commence mass account transfer	5/3/06
6.3 Manage supply portfolio and risk management (ongoing)	5/3/06
- Prepare daily load forecasts	5/3/06

[31] The County, as a CCA operator, will need to establish a legal relationship with SDG&E. It is anticipated that a service agreement will include processes for information exchange including electronic data interchange, procedures for settling financial transactions, treatment of customer bill payment funds transfer, credit terms, access to confidential customer information, audit provisions, and regulatory oversight and complaint processes.

TASK	ESTIMATED START DATE
- Balance portfolio with purchases and sales	5/3/06
- Schedule loads and resources	5/3/06
- Monitor credit of suppliers and mark to market exposure	5/3/06
- Maintain risk controls on supply portfolio	5/3/06
6.4 Perform Account Management and Settlements (ongoing)	5/3/06
- Process customer transfers into and out of program	5/4/06
- Receive and respond to customer inquiries	5/4/06/
- Pay electric suppliers	5/19/06
- Obtain customer meter data from IOU	6/2/06
- Prepare bill calculations	6/2/06
- Provide bill amounts to IOU	6/2/06
- Apply statistical load profiles to meter data and submit to ISO for settlement	6/2/06
- Pay IOU transaction fees	6/2/06
- Receive remittances from IOU from customer collections	6/19/06
- Verify ISO settlement statements and pay ISO charges	7/6/06
6.5 Distribute third opt-out notice	6/2/06
6.6 Complete mass account transfer	6/2/06
6.7 Process opt-outs	6/3/06
6.8 Prepare operating statements and financial reports (ongoing)	6/19/06
6.9 Distribute fourth opt-out notice	7/6/06
6.10 Process opt-outs	7/7/06