# Levelized Cost of Various Resource Scenarios for Serving CCA Customer Load in the City and County of San Francisco (Task 4 of 5)

## (DRAFT REPORT)

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## 1.1 Introduction

> **Purpose and Use of Report**
>
> • This report investigates the levelized cost of various resource portfolio scenarios for serving CCA customer load.
>
> • Prior reports addressed in- and out-of-City renewable resources and the potential economic impact on the CCA program.
>
> • A subsequent report will address recommendations relative to the CCA program based on this research.

The San Francisco Public Utilities Commission (SFPUC) retained George E. Sansoucy, P.E., LLC (GES) to prepare this Task 4 report which compares various supply resources and energy efficiency measures that could be used to serve Community Choice Aggregation (CCA) customer load. The results of the analysis presented in this report are intended to assist the SFPUC in assessing the cost of various portfolios and resource mixes associated with the CCA program which call for either the City and County of San Francisco (CCSF) or its Energy Service Provider (ESP)[1] to utilize a wide range of resources both within and outside of the CCSF. The CCA Draft Implementation Plan (CCA DIP) calls for a specific mix of 360 megawatts (MW) which includes renewable, distributed generation or energy efficiency measures with approximately 210 of the total 360 MW preferred within the jurisdictional boundaries of the CCSF.

The CCA DIP sets forth various directives regarding the type, location, and amount of renewable resources and energy efficiency to be used in satisfying CCA customer electric demand. The analysis presented within this report compares the estimated cost of serving CCA customer demand under the CCA DIP relative to the cost of Pacific Gas and Electric Company (PG&E) generation or supply services as well as two other scenarios that address the cost of alternative options. The information and analyses presented in this report draw up information developed in the prior reports (Tasks 1 through 3) as well as information on the cost of market purchases and energy efficiency and demand response measures. The four supply scenarios presented in this report are summarized as follows:

1. PG&E's cost of generation service in the CCSF.

2. Portfolio based on the CCA DIP utilizing in-City renewable energy resources and 51% renewable energy mix.

[1] An ESP is an individual or company that contracts directly with its customers to provide electric supplies. ESPs may serve only selected markets, such as large commercial and industrial customers, or all customers including residential.

3. Portfolio utilizing out-of-City renewable resources to satisfy 51% renewable energy mix. This scenario relies on construction and purchase of out-of-City resources to serve the CCA customer load.

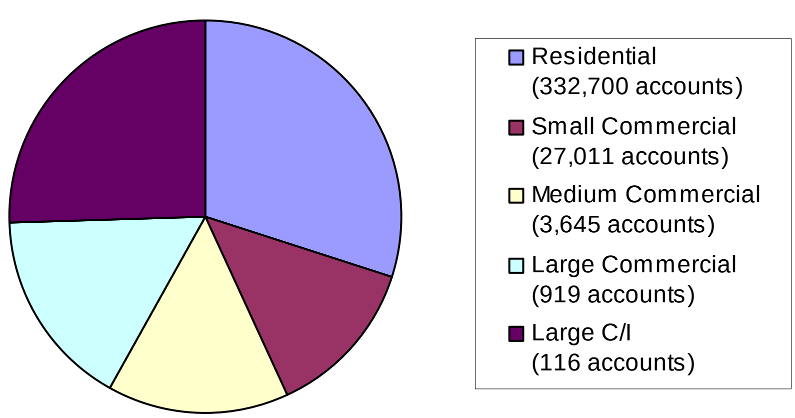
4. Portfolio utilizing out-of-City resources to satisfy a 20% Renewables Portfolio Standard (RPS).

## 1.2 Current and Future Supply Costs

The CCSF is part of PG&E's service territory and electricity is provided pursuant to regulations established by the California Public Utilities Commission (CPUC) that address pricing and level of service. The retail rates charged by PG&E include the bundled or total cost of providing electricity throughout this service territory. Current PG&E customers in the CCSF that choose to become customers of the CCA program will no longer pay for the generation component of PG&E's bundled rates and will instead pay the CCA program for the resources necessary to satisfy electric demand. The supply scenarios addressed in this report are intended to quantify the current and expected PG&E rates and compare these to three additional supply scenarios available in the marketplace to CCA customers. A comparison of the three supply scenarios with PG&E's expected rates provides a range of possible options and pricing levels associated with the CCA program's potential supply portfolio relative to service from PG&E.

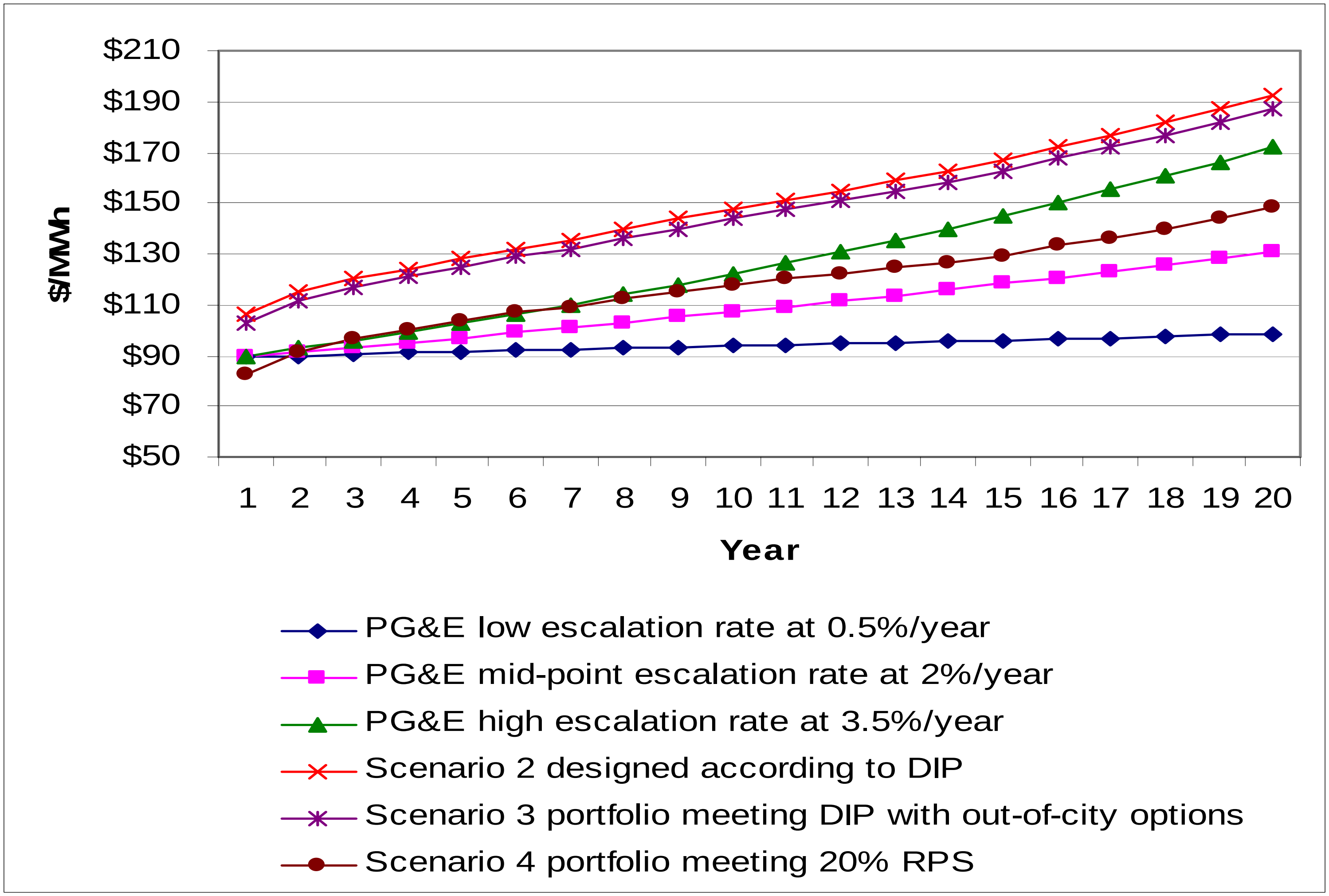
The cost of meeting customer demand in all of the scenarios addressed was based on existing customers within the CCSF eligible to participate in the CCA program. These customers represent those currently taking service from PG&E under its bundled service rates and do not include Direct Access (DA) customers or the municipal electric demand of the CCSF. Figure ES-1 illustrates the number of accounts by major rate class and relationship of annual consumption.

**Figure ES-1**
**Annual Energy Consumption by Customer Class**



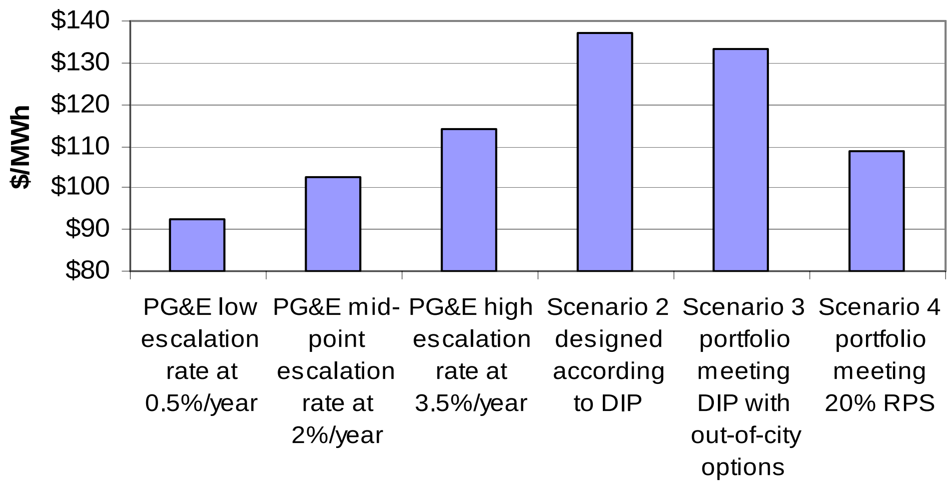
The customer data presented above was used to estimate hourly, monthly, and annual electric energy demand necessary to be procured under each of the four scenarios. In the case of PG&E's rates (Scenario 1), the current rates were applied to the customer data to estimate the average annual cost in the CCSF. In Scenarios 1 through 3, various resource mixes were utilized to estimate the annual cost over a 20-year period. The results of these analyses are presented in Figure ES-2.

**Figure ES-2**
**Comparison of Supply Costs**
**Under Scenarios Addressed in This Report**



The levelized cost of electricity (LCOE) associated with each scenario is set forth below in Figure ES-3 and demonstrates the cost of each portfolio scenario relative to PG&E's cost of serving customer load.

**Figure ES-3**
**Comparison of 20-Year LCOE**
**of Various Portfolio Scenarios**




In all but the highest escalation rate case for PG&E, the LCOE associated with its generation supply costs are lower than all of the alternative scenarios. The scenario with the highest LCOE is that developed around the CCA DIP due to the requirements associated with in-City renewable development, energy efficiency, and a 51% RPS by 2017. The least cost alternative (Scenario 4) in the table above is the minimum state requirement for RPS with no in-City requirements. As of November 2009, PG&E is unlikely to achieve the 20% RPS by 2010 as required by California law.

In all of the instances, no costs are included for non-bypassable surcharges associated with departing customers as these are beyond the scope of this analysis. However, it is likely, given the low cost of short-term supply utilized in the alternative scenario, that PG&E will claim that departing load has caused its costs to be stranded and seek relief at the CPUC. Therefore, the actual cost to CCA customers may be more than that presented above once these non-bypassable surcharges are addressed before the CPUC.

## 2.1 Introduction

This report (Task 4) is the fourth in a series of five reports that will address the cost and rate consequences associated with the 210 MW of in-City resources and a 51% renewable energy requirement by 2017. The San Francisco Public Utilities Commission (SFPUC) retained George E. Sansoucy, P.E., LLC (GES) to prepare this Task 4 report which compares various supply resources and energy efficiency measures that could be used to serve Community Choice Aggregation (CCA) customer load. The results of the analysis presented in this report are intended to assist the SFPUC in assessing the cost of various portfolios and resource mixes associated with the CCA program which call for either the City and County of San Francisco (CCSF) or its Energy Service Provider (ESP)[2] to utilize a wide range of resources both within and outside of the CCSF. The CCA Draft Implementation Plan (CCA DIP) calls for a specific mix of 360 megawatts (MW) which includes renewable, distributed generation or energy efficiency measures with approximately 210 of the total 360 MW preferred within the jurisdictional boundaries of the CCSF.

**Purpose and Use of Report**

- This report investigates the levelized cost of various resource scenarios for serving CCA customer load.
- Prior reports addressed in- and out-of-City renewable resources and the potential economic impact on the CCA program.
- A subsequent report will address recommendations relative to the CCA program based on this research.

The previous and subsequent tasks are summarized as follows:

- Task 1 included the theoretical and technical potential for renewable resources within the CCSF.
- Task 2 included the economic potential of those resources considered theoretically and technically viable within the CCSF. This task addressed the cost of these resources to CCA program customers using the estimated capital cost, O&M expense, and financial incentive for each of the resources selected, and analyzed the use of for-profit and not-for-profit capital structures and financing.
- Task 3 included the availability and levelized cost of out-of-City renewable energy resources that could be utilized to serve CCA customer load.

[2] An ESP is an individual or company that contracts directly with its customers to provide electric supplies. ESPs may serve only selected markets, such as large commercial and industrial customers, or all customers including residential.

- Task 5 is a report setting forth any recommendations that could enhance the CCA program based on the investigations and analyses set forth in Tasks 1 through 4.

## 2.2 CCA Program Resource Requirement

The implementation of the CCA program will require that, among other things, sufficient electric resources are available to serve electric customers. Pacific Gas and Electric Company (PG&E) will no longer be responsible for supplying the generation and demand reduction resources necessary to serve the electric requirements of customers that become part of the CCA program. Instead, customer electric requirements will be satisfied by the CCA program resource portfolio. This portfolio is expected to utilize a wide range of renewable and non-renewable resource options to ensure that the electrical supply and demand-side resources are cost effective, reliable, and meet the criteria set forth by the CCA program directives.

## 2.3 Purpose and Scope of the Analysis

The purpose of this report is to assess how various resource portfolios compare with PG&E's current and expected costs of providing supply and demand-side resources in the CCSF. The scope of our analysis is to provide an estimate of the annual and levelized cost of these various portfolios associated with serving the CCA electric load relative to the expected PG&E rates.

### 2.3.1 Information Developed in Prior Tasks

The estimated cost of serving the CCA program electric requirements was developed from the research and analyses presented in the Tasks 1 through 3 reports as well as information gathered in conjunction with this report. The information developed in prior reports and utilized in this Task 4 report includes:

- Availability and cost of in-City renewable resources (Tasks 1 and 2)
- Availability and cost associated with out-of-City renewable energy resources (Task 3)

### 2.3.2 Information Developed for this Task

Research and analyses associated with the following:

- CCA customer mix and electric demand in the CCSF
- Current and expected PG&E generation rates

- Availability and cost of wholesale electric purchases
- Energy efficiency measures capable of eliminating or reducing customer load
- Availability and cost of other resources potentially available to the CCA program such as electricity produced by the Hetch Hetchy Reservoir system

### 2.4 Scenario Summary

The cost of serving customer load over a 20-year period was developed using four scenarios that are summarized as follows:

1. PG&E's cost of generation service in the CCSF.
2. Portfolio based on the CCA DIP utilizing in-City renewable energy resources and 51% renewable energy mix.
3. Portfolio utilizing out-of-City renewable resources to satisfy 51% renewable energy mix. This scenario relies on construction and purchase of out-of-City resources to serve the CCA customer load.
4. Portfolio utilizing out-of-City resources to satisfy a 20% Renewables Portfolio Standard (RPS).

In Scenarios 2 and 3, the annual and levelized cost of electricity necessary to satisfy the total potential CCA customer load was developed for a 20-year period using the supply resources, energy efficiency, and demand reduction options available in- and out-of-City. The levelized cost of electricity (LCOE) for each scenario is compared with PG&E's current and future rates to estimate the economic potential of each scenario. Actual results will be a function of future fuel and electric commodity prices, customer retention, and other economic events that are impossible to predict at this time. Therefore, GES does not make any representations about the future price estimates which may be different than those set forth in this report.

It is anticipated that future work performed on behalf of the CCA program will address a more detailed analysis of actual customer electric demand and the cost of serving this demand based on the selection of an ESP.

## 2.5 Report Organization

The report is organized into the following sections.

- Section 3.0 Methodology and Assumptions

  This section describes the general approach employed in this report, the extent of the information gathered, and general assumptions regarding customer load and resources used to satisfy this demand.

- Section 4.0 Resource Scenarios

  This section sets forth the assumptions and results of the four scenarios addressed in this report.

## 3.1 Introduction

The CCA DIP sets forth various directives regarding the type, location, and amount of renewable resources and energy efficiency to be used in satisfying CCA customer electric demand. This report analyzes the estimated cost of serving CCA customer demand under the CCA DIP relative to the cost of PG&E generation or supply services as well as two other scenarios that address the cost of alternative options.

> **Summary of Four Scenarios**
>
> • PG&E generation rates
>
> • Generation costs under the Implementation Plan
>
> • Generation costs using out-of-city resources to satisfy the Implementation Plan
>
> • Out-of-city resources to meet 20% RPS

The information and analyses presented in this report draw up information developed in the prior reports (Tasks 1 through 3) as well as information on the cost of market purchases and energy efficiency and demand response measures. The cost of serving customer demand was estimated based on four scenarios, summarized as follows:

1. PG&E's cost of generation service in the CCSF.
2. Portfolio based on the CCA DIP utilizing in-City renewable energy resources and 51% renewable energy mix.
3. Portfolio utilizing out-of-City renewable resources to satisfy 51% renewable energy mix. This scenario relies on construction and purchase of out-of-City resources to serve the CCA customer load.
4. Portfolio utilizing out-of-City resources to satisfy a 20% RPS.

The four scenarios identified above address only the procurement of generation resources, energy efficiency, and/or demand response measures. The estimates in this report do not include costs that customers will bear irrespective of their ESP such as distribution, transmission, administrative, and public benefit charges which may continue to be paid to PG&E. In addition, the potential "Cost Responsibility Surcharge"[3] associated with costs incurred by PG&E that will become "stranded" should certain customers leave the system are not included. These charges levied

[3] The Cost Responsibility Surcharge (CRS) assures that the utilities' remaining bundled customers will remain financially indifferent to the departure of load from bundled service to a CCA Program's procurement portfolio. Essentially, the departure of customers from the utility to a CCA should not result in stranded costs that the utility's remaining bundled customers would have to pay. California Public Utilities Commission *Community Choice Aggregation Report to the California Legislature*, January 1, 2006 at: http://docs.cpuc.ca.gov/published/REPORT/52563.htm.

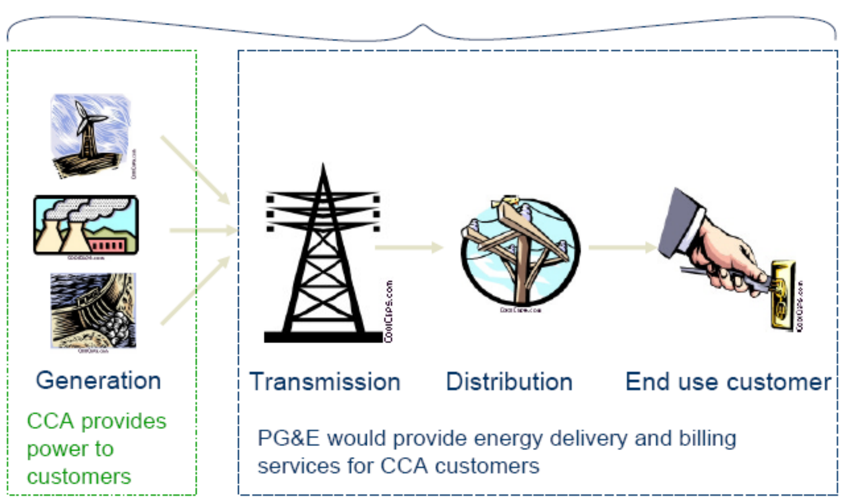
against departing customers would be determined by an analysis performed by the California Public Utilities Commission (CPUC) pursuant to Sections D-04-12-048 and D-06-07-029 and are anticipated to be addressed in future work performed on behalf of the CCA program.

### 3.2 Resources Necessary to Serve the CCA Customer Program

The implementation of the CCA program will require that, among other things, sufficient electric resources are available to serve the program customers. PG&E will no longer be responsible for supplying the resources necessary to serve the customers that are part of the CCA program. The expectation is that the CCA program supply mix will utilize a wide range of renewable and non-renewable supply-side resources as well as energy efficiency and demand-side management programs to ensure that the electricity delivered to its customers is cost effective, reliable, and meets the criteria set forth by the CCA program directives.

In order to understand the range of potential supply- and demand-side resources required to serve the CCA program customers' electric requirements, it is helpful to understand the basics of electric delivery and the responsibility of both the CCA program and PG&E in ensuring reliable and cost effective service to customers within the CCSF. The electric system can be broken down into three basic components which are 1) supply or generation, 2) transmission, and 3) distribution. All three of these components are necessary for reliable electric delivery to the customer. Figure 3-1 is an illustration of the components necessary for the operation of a complete electric system and the responsibility of both the CCA program and PG&E.

**Figure 3-1**
**Illustration of Electric System Components**




Source: SFPUC Power Enterprise *Community Choice Aggregation Program Status Update, February 10, 2009*, p. 5

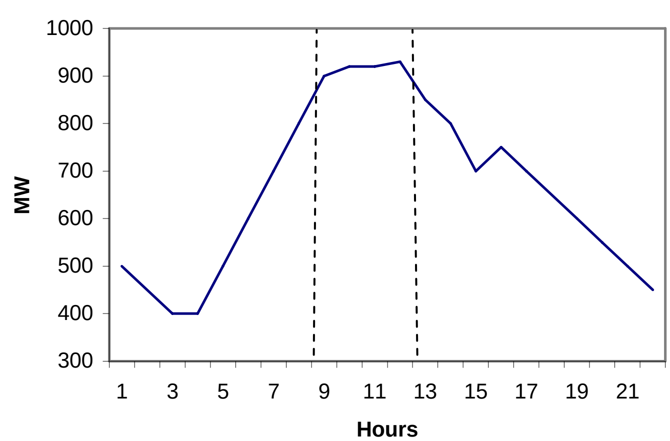
In providing electric customers with generation or demand response resources, the CCA program will have to ensure that its mix of resources meets both the physical requirements of the customer and the goals of the CCA program. This will require that the selected resource mix matches the demands of electric customers instantaneously over the course of a day, month, and year. In providing this service, the resource mix required will need to have various performance characteristics that ensure this balance between customer demand and corresponding supply meets the stringent physical requirements of the electric system.

**Electric Units of Measure**

- **Watt** – Basic measure of electricity (think of 60 or 100 Watt light bulbs
- **Kilowatt (kW)** - 1,000 Watts or enough electricity to power ten 100 Watt light bulbs
- **Megawatt (MW)** – 1,000 Kilowatts or enough energy to operate a medium-sized office tower
- **Kilowatt-hour (kWh)** – Represents one kW operating for one hour
- **Megawatt-hour (MWh)** – Represents one MW operating for one hour

To illustrate this point, an illustrative daily load profile for the CCSF is shown in Figure 3-2 and shows the megawatt demand for electricity over the course of a day and the magnitude of the megawatts or resources necessary to satisfy these demands. In this example, a peak system requirement of approximately 750 MW plus a reserve, to ensure against unexpected plant outages, will be necessary to serve customer demand in the hours of 8:00 AM to 12:00 PM. This example also illustrates how this "peak demand" only lasts for several hours and that the resources being utilized must be able to increase and decrease their output to match this demand.

**Figure 3-2**
**Illustrative Hourly Loads**
**for a High Usage Electric Day**



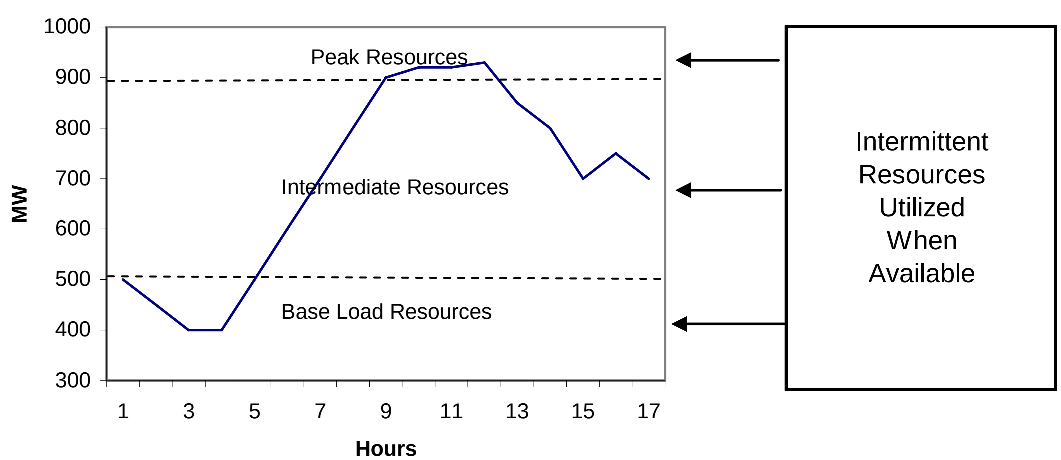
In order to serve this type of load, the resource mix will have to rely upon several types of generating technologies, demand-side resources, and peak shaving or storage resources as it is typically not physically possible or economically feasible for a single resource or supply to meet these variations.

In satisfying the customer demand as set forth in Figure 3-2, the CCA program resource mix will employ base load, intermediate, peaking, and intermittent supply-side resources and demand-side measures, each designed and priced to match a particular component of the hourly customer load. These resources could be owned by the CCA program or contracted on a short- or long-term basis, depending on the cost and benefits associated with each option.

### 3.2.1 Discussion of Supply-Side Resources

Supply-side resources refer to the use of power generating equipment of various design, fuel, and technology mix that satisfy customer demand. Supply resources utilized to provide electric service typically include a wide range of generating equipment used to meet particular system requirements based on its physical and economic characteristics. The demand and resources that are utilized to satisfy this demand are illustrated in Figure 3-3 and discussed below.

**Figure 3-3**
**Illustrative Hourly Loads and**
**Corresponding Supply Resource**




The base load electric requirements are those experienced around-the-clock, as illustrated in Figure 3-3, and represent approximately 500 MW of power demand in this example. These types of resources typically include nuclear, certain hydroelectric projects, biomass, combined heat and power (CHP), and other fossil-fired plants that run continuously in most hours of the year. These resources typically have high upfront capital costs but low operating costs as each is expected to operate a significant percentage of the year, typically greater than 80%.

Intermediate or cycling units are those units operated daily but typically only during the peak hours[4] to satisfy the electric demand during hours when usage is elevated. These units are not expected to operate every day and often are not operated during weekends when electric demand is low. These resources are typically fossil-fired units that operate approximately 30% of the year and can be depended upon to start and follow electric demand over the course of the day and shut down during times of low demand.

Peaking resources are those units necessary for only a few minutes or hours each day that can be relied upon at the height of electric demand. These units are also almost always fossil-fired and operate less than 5% of the year.

**Supply Resource Categories**

- **Base Load Units** – Resources capable and intended to operate at or near full load around-the-clock
- **Intermediate Units** – Resources that cycle daily to meet changing load requirements
- **Peaking Resources** – Operate infrequently to meet high electric demand
- **Intermittent Resources** – Cannot store a fuel source and therefore have limited operating hours.

In addition to these three general categories of resources, a fourth category is used in this report to characterize those resources that operate intermittently and includes most renewable resources. The Federal Energy Regulatory Commission (FERC)[5] has defined an intermittent resource as "an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints."[6]

Intermittent resources are intended to be available to operate 100% of the time but due to environmental constraints such as the lack of wind or sun are at the mercy of Mother Nature for the generation of electricity.[7] Therefore, these resources provide some level of capacity in meeting electric demand but almost

[4] Peak hours typically represent the hours Monday through Friday 6:00 AM to 10:00 PM, or 16 hours per day.
[5] The FERC regulates the price, terms, and conditions of power sold in interstate commerce and regulates the price, terms, and conditions of all transmission services. FERC is the federal counterpart to state utility regulatory commissions.
[6] FERC Inbalance Provision for Intermittent Resources, Docket No. RMO5-10-000.
[7] Wind, photovoltaic (PV) solar, tidal power, and some hydroelectric resources are considered intermittent resources as these units cannot store their fuel to coincide with times of peak demand in the electric system.

always will require back-up resources, usually fossil-fired, to compensate for potential failures to operate.

The supply-side resources used to meet customer demand are addressed in Tasks 1 through 3 and include in- and out-of-City renewable resources as well as market-based purchases. The costs of these are further addressed in Section 4 under each scenario which addresses how customer demand is satisfied utilizing these supply-side resources.

### 3.2.2 Discussion of Demand-Side Resources

In addition to supply-side resources, measures that eliminate or lower demand can be used to satisfy electric customer requirements and are generally referred to as demand-side resources. The demand side resources addressed in this analysis include a wide range of options from resources that create permanent efficiency to those that reduce demand during periods of peak energy consumption.

The CCA DIP calls for "107 Megawatts of local energy efficiency and conservation measures" as part of its resource mix used to satisfy CCA customers' electric demand which, for purposes of this report, includes a wide range of options.

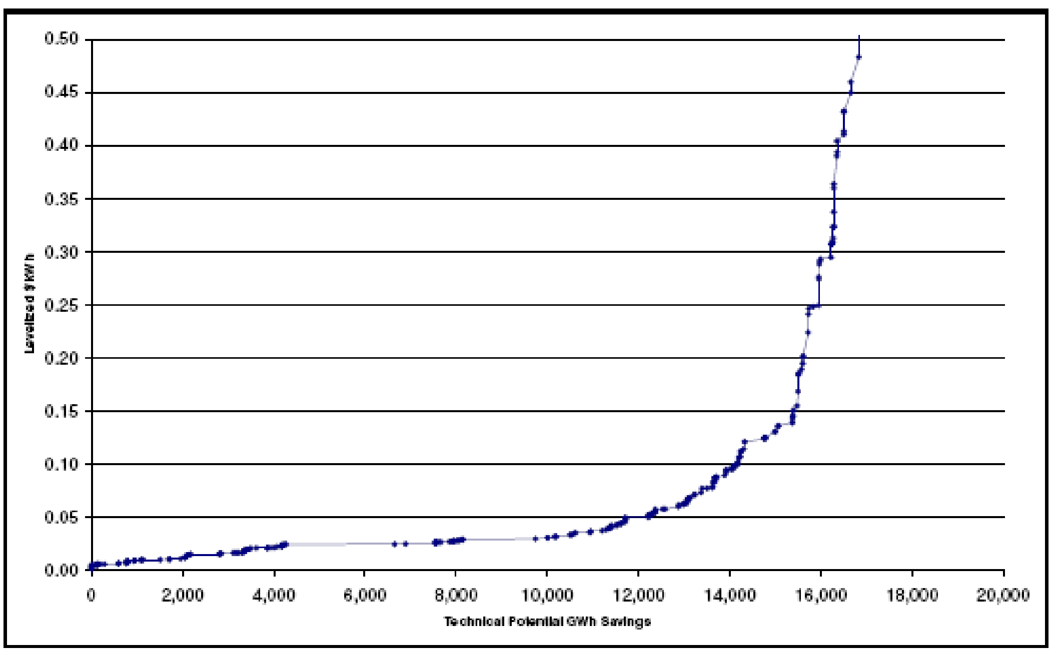
The use of energy efficiency or demand-side management is a long standing practice in the utility industry as a source of offsetting existing or future demand and managing pending loads. California Assembly Bill (AB) 2021, passed in 2006, requires utilities to engage in energy efficiency as a means of reducing consumption by 10% over a ten-year period, or 1% per year. This goal of energy efficiency is considered typical and illustrates how ambitious the CCA goal of 107 MW of energy efficiency is as it would represent approximately 14% of the total demand in the CCSF.

As with any resource or commodity, the cost of energy efficiency increases relative to the demand for these services. Therefore, a small amount of energy efficiency may be obtained at a modest cost with higher levels of energy efficiency requiring greater levels of investment to develop and implement in the marketplace. The availability and cost of energy efficiency measures were not addressed in prior reports prepared by GES. Therefore, in assessing the availability and cost, additional research was performed with respect to these resources based on existing or proposed measures. However, no study or analysis was undertaken to determine if it is possible to utilize 107 MW of demand reduction in the CCSF and the cost associated with these types of resources. The following is a summary of potential costs and availability of such measures. GES makes no representation beyond those identified below as to the cost or availability of such measures.

The cost of energy efficiency measures varies by type of installation, technology, and age of infrastructure to which the measures are applied. Typically, energy efficiency has the greatest cost benefit in new construction where design and systems can maximize the energy savings. For example, the use of more insulation in new construction can reduce the size of the heating, ventilating, and air conditioning (HVAC) system and lead to lower energy demand and increased energy efficiency. These same savings and/or opportunities are unavailable in existing or older buildings and typically result in higher costs.

An illustration of this is PG&E's estimated cost of energy efficiency from a 2008 study performed by Itron, Inc. which is shown in Figure 3-4.

**Figure 3-4**
**PG&E Supply Curve Technical Energy Efficiency Potential 2007-2016 (GWh)**




Source: Itron, Inc. *California Energy Efficiency Potential Study*, September, 10, 2008 p. 4-35 at: http://www.calmac.org/publications/PGE0264_Final_Report.pdf

This curve illustrates how steeply the energy efficiency cost rises as the less expensive measure or "low hanging fruit" is utilized. In addition, these levelized costs do not include PG&E program costs or the administrative costs associated with each of the measures.

These PG&E program costs are a significant component of the programs and include all of the administrative costs associated with designing, tracking, and reporting on the programs. The cost of the energy efficiency plus the PG&E program cost for a sample of PG&E's measures is illustrated in Table 3-1. In some instances, the PG&E program costs are twice as much or more than the cost of the energy efficiency measure.

**Table 3-1**
**PG&E Electric Supply Curve Data, 2016**

| Technology Description | Sector | Levelized Supply Cost ($/kWh) | Levelized Supply Cost with Program Cost ($/kWh) | Technical GWh 2016 |
|---|---|---|---|---|
| Screw-in CFL greater than 24 watts | Existing Commercial | 0.007 | 0.035 | 305.09 |
| ENERGY STAR Transformers | Existing Industrial | 0.024 | 0.028 | 1.10 |
| Fans efficient motor practices (6-100 HP) | Existing Industrial | 0.028 | 0.035 | 10.23 |
| Window Film - Chiller | Existing Industrial | 0.064 | 0.071 | 12.37 |
| Small Copier ENERGY STAR | Existing Commercial | 0.093 | 0.104 | 34.82 |
| Air Conveying Systems | Existing Industrial | 0.144 | 0.149 | 0.28 |

Source: Itron, Inc. *California Energy Efficiency Potential Study*, September 10, 2008, Appendix B, Table B-1at: http://www.calmac.org/publications/PGE0264_Final_Report.pdf

The information presented above on the PG&E supply curve for efficiency measures and the supply plus the program costs demonstrates the range of costs associated with these measures can range from less than 1¢/kWh (without program costs) to as much as $1.425/kWh for the most expensive measures.

The potential cost of energy efficiency measures and demand reduction costs used in assessing the CCA program supply costs are based on the annual energy efficiency program costs associated with publicly-owned utilities (POUs) in the State. In 2006/2007, POUs spent $63 million on energy efficiency programs for a reduced peak of 57 MW and approximately 254,000 MWh of energy savings. The 2007 and 2008 budget for energy efficiency was $146 million and reduced demand by 118 MW and saved 541,000 MWh of energy.[8]

These program costs and energy savings indicate that it cost approximately $1,100 to $1,200/kW of reduced peak per year, or about $250/MWh, to reduce energy consumption in the magnitude addressed in the CCA DIP. These costs are similar to the costs incurred by PG&E and other utilities if total program

[8] California Energy Commission *Achieving Cost-Effective Energy Efficiency for California: An AB 2021 Progress Report*, December 2008, CEC-200-2008-007, p. 11.

costs are included with the actual costs for the efficiency and demand reduction measures.

The costs incurred by the State's POUs indicates the magnitude of the money that is necessary to reduce demand on an annual basis and how aggressive a 107 MW requirement is relative to all of the State's POUs' savings of 57 and 118 MW for 2006 through 2008. These POUs include 39 entities that range in size from the Los Angeles Department of Water and Power (LADWP) to small entities serving less than 100 customers. The largest in this group include the LADWP and the Sacramento Municipal Utility District (SMUD).

In estimating the scenario costs for the CCA program, it was assumed that 107 MW of energy efficiency and demand reduction could be captured for $1,000 to $1,200/kW per year. However, actual results may increase these figures due to the large amount of energy efficiency and demand-side management which would have to be developed within the CCSF.

## 3.3 CCA Program Electric Demand Requirements

The CCSF currently is host to three types of electric customers. These include those taking bundled service from PG&E, Direct Access (DA) customers that only utilize PG&E for transmission and distribution, and the CCSF municipal load which is supplied either at the direction or control of the SFPUC. The customers considered most probable to participate in the CCA program are those taking bundled service from PG&E. It is assumed that DA customers and municipal load will not participate in the CCA program. As discussed above, the CCA program will require that under each scenario there is sufficient electric capacity, energy, and green attributes of this energy to satisfy CCA customers. Since it is impossible to tell exactly the number of customers and associated load that will ultimately encompass the CCA program, an estimate was made utilizing 100% of the load and associated energy requirements of the customers eligible to participate in the CCA program.

The customer load data utilized in this report is based on estimates prepared by GES and the SFPUC and is considered to represent a reasonable estimate of the potential number of customers, load profile, and energy consumption of the CCA program in the CCSF. This customer and load data is utilized for each of the four scenarios to provide a consistent basis for procuring the necessary energy resources to satisfy the CCA program. Actual CCA customers and loads will vary based on the number of customers retained and actual mix of resources utilized to satisfy this demand. However, for purposes of this analysis, the information presented below is considered to be a reasonable representation of the potential CCA customer load.

A summary of the major customer classes is provided in Table 3-2 below. These five major classes represent the majority of customer load. Approximately 1% of the load is not represented and includes seasonal and electric vehicle service, streetlights, standby service, and agricultural.

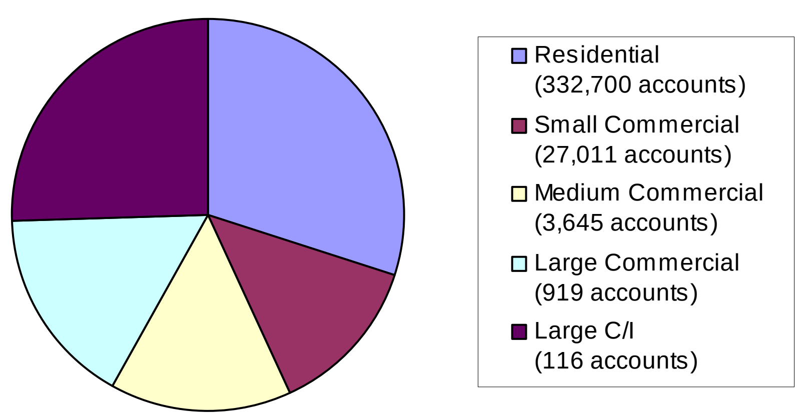
**Table 3-2**
**PG&E Bundled Service in the CCSF in 2008**

| Customer Class | Accounts | Yearly Aggregate Consumption (MWh) |
|---|---|---|
| Residential | 332,700 | 1,383,488 |
| Small Commercial | 27,011 | 608,927 |
| Medium Commercial | 3,645 | 688,962 |
| Large Commercial | 919 | 759,593 |
| Large C/I | 116 | 1,186,231 |
| **Total** | **364,391** | **4,627,201** |

Source: SFPUC

The average annual energy consumption by customer class from Table 3-2 is shown in Figure 3-5 which illustrates how large commercial/industrial customers account for 116 accounts but consume almost 25% of the electricity in the CCSF.

**Figure 3-5**
**Annual Energy Consumption by Customer Class**



The information presented above represents the estimated annual energy consumption an ESP would be required to serve if all eligible customer accounts become part of the CCA program. In addition to the annual energy consumption, the ESP must assure that the peak demand associated with these consumption figures are met and in compliance with California ISO (CAISO) requirements.

In serving this customer load, the resource utilized would have to satisfy certain physical and regulatory requirements. The CPUC's capacity standards require that an ESP or the CCA itself demonstrate that it has physically secured 90% of its projected peak load for the months of May to September one year in advance of commencing service. In addition to 90% of its peak load, it must also demonstrate a 15% reserve margin. The requirements also state that on a month ahead basis, 100% of peak load plus a minimum 15% reserve margin must be owned or controlled by the ESP or CCA. A portion of the CCA program's load must be procured locally. In this case, in the greater Bay Area as defined by the CAISO.

The local capacity requirement is a percentage of the total PG&E service area load capacity requirement adopted by the CPUC. The formula for calculating this requirement is as follows:

*Local Capacity Requirement = (Local Capacity Requirement ÷*
*Total PG&E Service Area Capacity Requirement × Total Local*
*Capacity Requirements in PG&E Service Area*

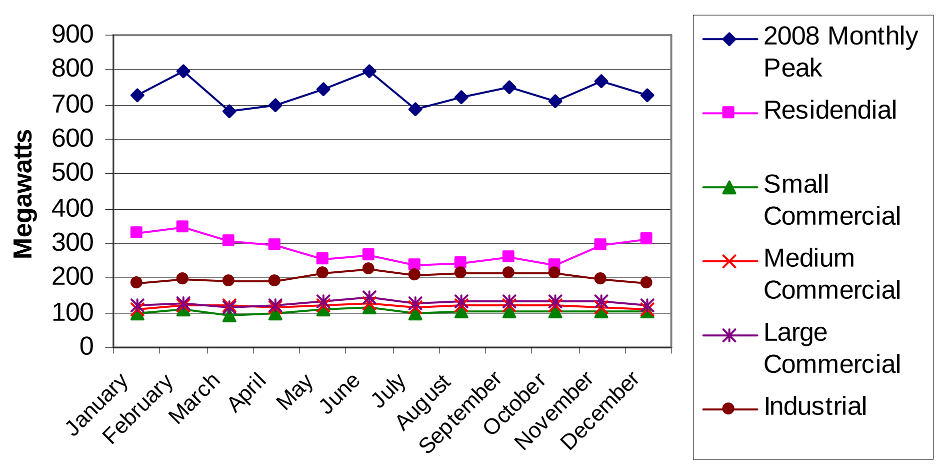
The ESP or CCA itself must demonstrate compliance with the local load requirement of CPUC requirements or request a waiver that local load is not necessary. In addition, certain resource adequacy filings must be made on behalf of customer load. The estimated hourly load and monthly peak demands for the CCA program were developed for the total potential CCA customers identified in Table 3-2. These estimates were based on the 2008 customer data and work previously performed by the SFPUC with respect to the anticipated shape on hourly demand of this load. The combination of these two sources was used to develop the hourly demand and energy requirements that the CCA program would have to procure. The estimated monthly on- and off-peak consumption along with the estimated peak demand is illustrated in Table 3-3.

**Table 3-3**
**Estimated Monthly Usage and CCA Peak and Peak Demand**
**By Customer Class Using SFPUC Load Shapes**

| Month | Estimated Monthly Usage 2008 On Peak (MWh) | Off Peak (MWh) | Total (MWh) | 2008 Monthly Peak |
|---|---|---|---|---|
| January | 230,938 | 171,897 | 402,835 | 726 |
| February | 219,230 | 176,966 | 396,196 | 797 |
| March | 202,086 | 178,846 | 380,932 | 684 |
| April | 217,960 | 166,299 | 384,259 | 696 |
| May | 211,320 | 171,866 | 383,186 | 743 |
| June | 208,216 | 172,464 | 380,680 | 797 |
| July | 217,116 | 160,619 | 377,735 | 688 |
| August | 204,671 | 179,328 | 383,998 | 719 |
| September | 216,061 | 162,727 | 378,788 | 750 |
| October | 218,055 | 158,014 | 376,069 | 710 |
| November | 201,229 | 185,526 | 386,755 | 766 |
| December | 226,404 | 169,379 | 395,784 | 730 |
| **Total** | **2,573,286** | **2,053,931** | **4,627,218** | **N/A** |

This peak demand is comprised of the cumulative coincidental peak demand of the five major customer classes in the CCSF area taking bundled service from PG&E. The customer class demand and total CCA program demand are shown in Figure 3-6 for the first year of the analysis.

**Figure 3-6**
**CCA Peak Demand and Peak Demand**
**By Customer Class Using SFPUC Load Shape Estimates**



These demands are expected to stay relatively constant over the 20-year forecast period due to efforts by the CCSF and CCA program to promote energy efficiency and the overall trend in the marketplace to limit the growth in electric consumption.

### 3.4 Renewables Portfolio Standards

CCA programs are required by the CPUC regulation to procure a minimum percentage of its retail electric sales from qualified renewable energy resources. According to the RPS policies established in the State's Energy Action Plan, a CCA must include a renewable energy standard of no less than 20% of its load by 2010. The CPUC has ruled so far that the California CCA programs must comply with certain fundamental aspects of the RPS program. These include: a 20% requirement by 2010, increasing the renewable sales by at least 1% per year, reporting their progress to the CPUC, using short-term purchases for compliance, and being subject to penalties assessed by the CPUC.

It is anticipated that future resource procurement plans by the CCA program should assume that they will be subject to the same CPUC rulemaking as the investor-owned utilities (IOUs) in the State and may choose more stringent requirements than those set forth in State regulations. The renewable resources included in the various scenarios are assumed to comply with State requirements and satisfy the CPUC regulations with respect to CCA programs.

## 4.1 Introduction

The CCSF is part of PG&E's service territory and electricity is provided pursuant to regulations established by the CPUC that address pricing and level of service. The retail rates charged by PG&E include the bundled or total cost of providing electricity throughout this service territory. Current PG&E customers in the CCSF that choose to become customers of the CCA program will no longer pay for the generation component of PG&E's bundled rates and will instead pay the CCA program for the resources necessary to satisfy electric demand. The following scenarios are intended to quantify the relationship between these PG&E rates and three additional supply scenarios available in the marketplace. The assumptions used in developing the PG&E generation rates and supply costs associated with the other three scenarios are discussed below.

The annual supply costs, which include energy efficiency and demand-side management, of the various scenarios addressed in this report are set forth below in Figure 4-1 on a dollar per megawatt-hour basis over a 20-year forecast period. This figure illustrates how the various supply portfolios compare to the estimated generation-related charges associated with the PG&E rates using high, mid-point, and low price escalation. The scenarios considered are summarized as follows:

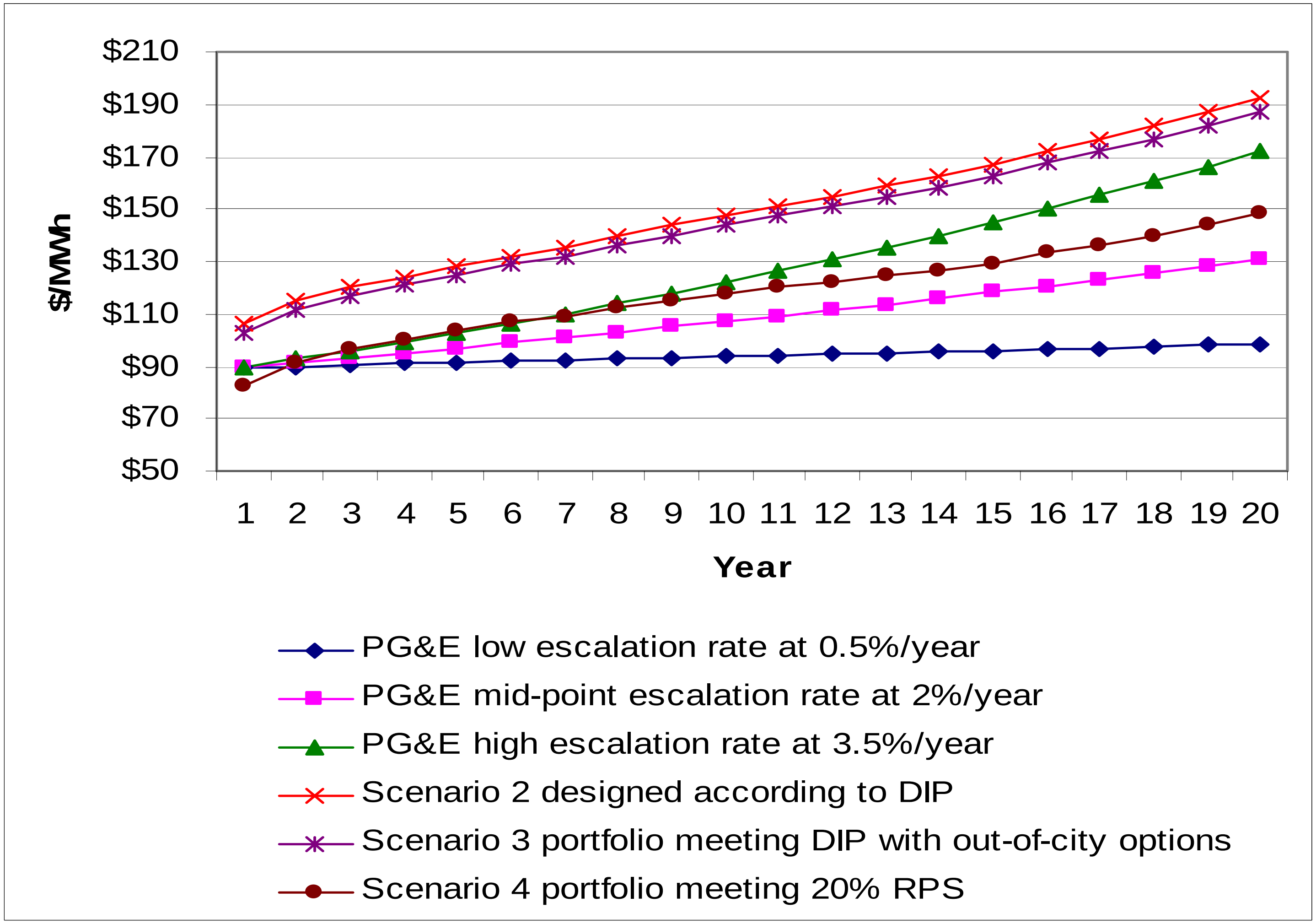
1. PG&E's cost of generation service in the CCSF.

2. Portfolio based on the CCA DIP utilizing in-City renewable energy resources and 51% renewable energy mix.

3. Portfolio utilizing out-of-City renewable resources to satisfy 51% renewable energy mix. This scenario relies on construction and purchase of out-of-City resources to serve the CCA customer load.

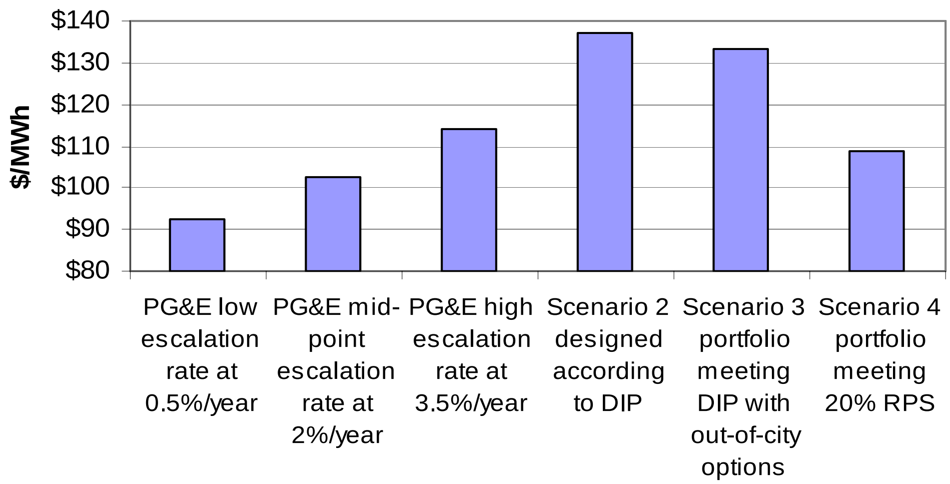
4. Portfolio utilizing out-of-City resources to satisfy a 20% RPS.

**Figure 4-1**
**Comparison of Supply Costs**
**Under Scenarios Addressed in This Report**



The levelized cost of electricity (LCOE) associated with each scenario is set forth below in Figure 4-2 and demonstrates the cost of each portfolio scenario relative to PG&E's cost of serving customer load.

**Figure 4-2**
**Comparison of 20-Year LCOE**
**of Various Portfolio Scenarios**




In all but the highest escalation rates for PG&E, the LCOE associated with its generation supply costs are lower than the three alternatives addressed in this report. The scenario with the highest LCOE is that developed around the CCA DIP due to the requirements associated with in-City renewable development, energy efficiency, and a 51% RPS by 2017. The least cost alternative is that which approximates the PG&E portfolio and meets a 20% RPS with no specific in-City requirements.

In all of the scenarios, no costs are included for non-bypassable surcharges associated with departing customers as these are beyond the scope of this analysis. However, it is likely given the low cost of short-term supply utilized in the alternative scenarios that PG&E will claim that departing load has caused its costs to be stranded and seek relief at the CPUC. Therefore, the actual cost to CCA customers may be more than that presented above once these non-bypassable surcharges are addressed before the CPUC.

The following sections describe the assumptions used in each of the scenarios presented above and provide additional discussion and support of the associated LCOE.

### 4.2 Scenario 1 – PG&E Rates

The PG&E electric customers in the CCSF currently purchase electricity pursuant to either the bundled rates, in the case of full service customers, or unbundled rates, in the case of DA customers. The generation or cost of supply associated with these bundled rates is the first scenario analyzed in this report as these rates will provide a benchmark against which to assess alternative resource scenarios.

The PG&E generation rates are based on the differences between the rates PG&E charges its bundled customers for full requirement services, which include the cost of providing energy, capacity, meeting the State's RPS requirements, and transmitting and distributing the electricity, and the cost to its DA customers for just the distribution and transmission of electricity. The rates used in this report are based on information provided to the CPUC in Advice Letter 3518-E dated September 1, 2009 which summarizes the current bundled and unbundled rates for the various PG&E rate classes.

PG&E's rates are intended to reflect the cost of service associated with serving each class of customer and include various tariffs for Residential; Small, Medium, and Large Commercial; and Large Commercial and Industrial. In addition, there are rates or tariffs for streetlights, agricultural, and other special rate classes. In estimating the rates for the CCSF under Scenario 1, PG&E's rates were based on an average PG&E rate for each major category and the estimated electric profile of the CCSF. While actual rates and profits may differ, this approach is considered to provide a reasonable estimate of the current PG&E rates for generation.

A summary of the average PG&E rates by general category for bundled and DA customers, along with the generation charges that the customer would avoid as part of the CCA program, is set forth in Table 4-1. These avoided charges are considered to reflect the cost of generation service associated with these rates.

**Table 4-1**
**Summary of PG&E Rates and Generation Rates**
**Avoided by CCA Customers**

| A | B | C | D |
|---|---|---|---|
| Title | Bundled Rates (kWh) | (Unbundled) Direct Access Rates (kWh) | Generation Service Charge (kWh) [B - C] |
| Residential | $0.16784 | $0.08486 | $0.08298 |
| Small Commercial | $0.16920 | $0.08190 | $0.08730 |
| Medium Commercial | $0.15174 | $0.04531 | $0.10643 |
| Large Commercial | $0.13805 | $0.04685 | $0.09120 |
| Large C/I | $0.13130 | $0.04348 | $0.08782 |

Source: CPUC Advice Letter 3518-E, 9/1/09.

The generation service charges in Column D of Table 4-1 above represent that portion of the PG&E bill that could be avoided by taking service from the CCA program prior to any non-bypassable charge specifically assigned to CCA program customers. The surcharges that may be assessed to CCA customers would be based on filings with the CPUC and are intended to compensate PG&E for previously incurred costs associated with serving customers. The figures below do not account for these surcharges which are beyond the scope of this analysis

As discussed previously, PG&E's customer data for 2008 was made available to the SFPUC and utilized in its recent solicitation for an ESP to serve customer load. This CCSF customer and load data combined with the generation charges in Table 4-1, Column D provide an estimate of the generation charges current CCSF customers pay as part of the PG&E bundled rates.

Table 4-2 is a summary of the customer data for the CCSF and the estimated PG&E generation rates by customer class. These calculations set forth in Table 4-2 illustrate that PG&E collects approximately $415 million in generation-related charges in the CCSF. The average rate for the CCSF load profile from Table 4-2 is approximately $0.09/kWh and represents the weighted average generation charges for the 2010 time period.

**Table 4-2**
**Summary of Customer Data and Related Costs of PG&E Generation Supply**

| A | B | C | D | E |
|---|---|---|---|---|
| **Customer Class** | **Accounts** | **Yearly Aggregate Consumption (MWh)** | **PG&E Generation Component of Rates (kWh) [Table 4-1]** | **Annual $ ($ in 000) [C × D]** |
| Residential | 332,700 | 1,383,488 | $0.08298 | $114,802 |
| Small Commercial | 27,011 | 608,927 | $0.08730 | $53,159 |
| Medium Commercial | 3,645 | 688,962 | $0.10643 | $73,326 |
| Large Commercial | 919 | 759,593 | $0.09120 | $69,275 |
| Large C/I | 116 | 1,186,231 | $0.08782 | $104,175 |
| **Total** | **364,391** | **4,627,201** | | **$414,737** |
| **Weighted Average** | | | **$0.0896** | |

Source: SFPUC

The PG&E generation rates shown in Table 4-2 represent the embedded cost of serving customers in the CCSF and reflect existing investments and contracts entered into by PG&E on behalf of retail customers. Therefore, in estimating future costs, both historic decisions as well as future economic conditions will drive the rate at which these generation components change over a 20-year forecast period.

In estimating the level of change in this analysis, several scenarios were considered and are based on information set forth by Navigant Consulting in association with work it performed for Marin County as well as rebuttal to this work by PG&E.

The range of potential rate increases is from 3.5% on the high end, which is consistent with forecasts made by Navigant Consulting in its analysis of the rates on behalf of Marin County, to 0.5% which is the low end of the range cited by PG&E in response to Marin County's Business Plan. In reviewing potential escalation rates, the high end is considered more reasonable given PG&E's requirement to attract more renewables to comply with existing and proposed RPS requirements. Therefore, an escalation of 2% was selected as representing both the mid-point and a reasonable rate of escalation for PG&E's generation related rates. The 2% escalation rate was used over the 20-year forecast period to develop the LCOE along with the high and low estimates discussed above to illustrate the impact of various rates of change.

The LCOE for the PG&E generation-related rates in the CCSF ranges from a low of $0.0926 to a high of $0.1140 based on a 10% discount rate. These are set forth below in Table 4-3 and provide a benchmark for the CCA program.

**Table 4-3**
**20-Year LCOE**
**of PG&E Generation Rates**

| Rate of Change | LCOE ($/kWh) |
|---|---|
| 0.5% | $0.0926 |
| 2.0% | $0.1025 |
| 3.5% | $0.1140 |

### 4.2.1 Conclusion – PG&E Rates (Scenario 1)

The PG&E generation rates are comprised of a wide range of owned and purchased resources that are paid for by existing PG&E retail customers. When analyzing the CCA program alternatives, it is reasonable to assume that the current rate of approximately $0.09/kWh or $90/MWh will escalate over the next 20 years within a range of 0.5 to 3.5%. This results in levelized costs of electricity which range from $0.0926 to $0.1140/kWh and can be used as a benchmark to measure alternative CCA portfolios.

## 4.3 Scenario 2 – CCA Draft Implementation Plan

The second scenario analyzed estimates the LCOE of providing service utilizing the supply mix set forth in the CCA DIP. This scenario measures the estimated annual and levelized cost of satisfying CCA consumer demand based upon the following resource mix:

- 51% renewable resources by 2017
- 31 MW of in-City solar
- 72 MW of local renewable resources
- 107 MW of local energy efficiency and demand-side management
- 150 MW of wind outside the CCSF

The remainder of the supply resource in this mix is assumed to be comprised of various resources procured on a short or long term basis. The resources are utilized to serve the CCA program's annual and monthly demand plus a 15% reserve margin. The following sections describe the assumptions utilized in estimating the portfolio costs in this scenario.

### 4.3.1 Customer Demand

The customer demand for the CCA program is based on the load and demand data previously presented in this report and the hourly load shapes developed by the SFPUC. This customer data and estimated load shape was used to calculate the on- and off-peak energy requirements and monthly peak demand that would be required to serve the CCA program.

This data provides the basis of the capacity and energy requirements the CCA program would have to procure along with the demand-side resources used to lower this electric demand. The on-peak hours were based on estimated hourly load data for the hours ending 7:00 AM to 11:00 PM Monday through Friday. All other hours were considered off-peak. The estimated CCA energy requirements and monthly peak load are set forth in Table 4-4.

**Table 4-4**
**CCSF Monthly Load Profile**

| Month | On Peak (MWh) | Off Peak (MWh) | Monthly Peak |
|---|---|---|---|
| January | 203,644 | 152,941 | 659 |
| February | 193,456 | 157,718 | 725 |
| March | 176,833 | 158,363 | 597 |
| April | 191,138 | 147,414 | 631 |
| May | 184,442 | 151,783 | 642 |
| June | 180,978 | 151,787 | 688 |
| July | 188,446 | 140,904 | 594 |
| August | 177,554 | 157,446 | 618 |
| September | 187,970 | 143,135 | 648 |
| October | 188,741 | 137,946 | 609 |
| November | 175,931 | 163,648 | 687 |
| December | 199,642 | 150,277 | 654 |
| **Total** | **2,248,774** | **1,813,364** | **N/A** |

The load data set forth above is similar to the 2008 data shown previously and is considered to represent a reasonable estimate of electric requirements in the CCSF. These energy and peak requirements are expected to remain constant over the forecast period due to conservation and load reduction measures as discussed previously. In estimating procurement requirements, load losses of 4% were assumed in calculating actual electric needs.

### 4.3.2 Supply- and Demand-Side Resources

The supply resources used to meet the customer demand identified above are based on a combination of resources contracted for via short- and long-term power purchase agreements (PPAs) and spot market purchases. These resources were matched to demand using an Excel spreadsheet which assumes all energy, capacity, reserves, transmission losses, and RPS requirements are met with either supply or demand-side resources.

In the CCA DIP scenario, it is assumed that the CCA program utilizes the resources set forth in Table 4-5 which lists the type and amount of energy delivered, system degradation, capacity contributions, and first-year cost for the various resources.

**Table 4-5**
**Supply Assumptions Used to Meet Demand**

| Resource | Amount (MW) | First Year On-Peak (MWh) | First Year Off-Peak (MWh) | Degradation % | First-Year Cost |
|---|---|---|---|---|---|
| In-City Ground-Mounted Solar | 31 | 735 | 0 | 0.5% | $256.00 |
| In-City Cogen | 72 | 24,703 | 27,857 | 0.0% | $94.38 |
| In-City Energy Efficiency Demand Response | 107 | 29,291 | 9,764 | 0.0% | N/A |
| Out-of-City Wind-Class 3/4 plus Transmission | 150 | 20,586 | 27,594 | 0.0% | $64.65 |

The resources presented in the previous table were those identified in Tasks 1 through 3 or, in the case of energy efficiency and demand response, estimated for this Task 4 report. The resources were selected to satisfy the scenario requirements and minimize cost to CCA customers. For example, solar resources were based on the least cost alternative and most reasonable resources for satisfying a 31 MW requirement. The 72 MW of in-City renewable was based on using combined heat and power (CHP) technology burning gas produced with anaerobic digestion.

The remainder of demand was satisfied using market purchases during on- and off-peak periods based on price estimates provided by Platts.[9] These are summarized in Table 4-6 below on an annual basis, while monthly prices were used to calculate the LCOE.

[9] Platts is a division of The McGraw-Hill Companies, Inc. and is the world's largest provider of energy information and research.

**Table 4-6**
**On-Peak and Off-Peak Energy and Capacity Prices**

| Hub | Year | On-Peak Avg ($/MWh) | Off-Peak Avg ($/MWh) | Annual $/kW-year |
|---|---|---|---|---|
| North Path 15 | 2010 | $59.00 | $42.50 | $50.75 |
| North Path 15 | 2011 | $68.13 | $49.88 | $59.01 |
| North Path 15 | 2012 | $71.25 | $51.25 | $61.25 |
| North Path 15 | 2013 | $71.08 | $53.29 | $62.19 |
| North Path 15 | 2014 | $71.98 | $54.01 | $63.00 |
| North Path 15 | 2015 | $73.20 | $55.62 | $64.41 |
| North Path 15 | 2016 | $74.20 | $56.39 | $65.30 |
| North Path 15 | 2017 | $76.73 | $57.80 | $67.27 |
| North Path 15 | 2018 | $77.61 | $58.84 | $68.23 |
| North Path 15 | 2019 | $78.79 | $60.35 | $69.57 |
| North Path 15 | 2020 | $78.68 | $61.69 | $70.19 |
| North Path 15 | 2021 | $78.55 | $62.50 | $70.53 |
| North Path 15 | 2022 | $78.94 | $62.57 | $70.76 |
| North Path 15 | 2023 | $77.99 | $63.85 | $70.92 |
| North Path 15 | 2024 | $79.43 | $64.94 | $72.19 |
| North Path 15 | 2025 | $81.95 | $67.10 | $74.53 |
| North Path 15 | 2026 | $82.50 | $67.72 | $75.11 |
| North Path 15 | 2027 | $84.44 | $68.96 | $76.70 |
| North Path 15 | 2028 | $86.14 | $70.88 | $78.51 |
| North Path 15 | 2029 | $80.14 | $67.07 | $73.61 |

Source: Platts

### 4.3.3 Conclusion - Portfolio Matches CCA Draft Implementation Plan (Scenario 2)

The specific resources utilized to meet the first-year customer demand included approximately 1.6 million MWh of specific resource generation with an additional 3 million MWh purchased for the marketplace. The renewable component was over 40% through 2017. This was then increased to 51% using out-of-City wind purchased at a cost of about $86/MWh.

The capacity associated with specific in- and out-of-City resources include 107 MW of energy efficiency and demand measures with a total nameplate capacity rating of 360 MW and a claimed rating of 217 MW due to the intermittent nature of the resource. The remainder of the capacity needed to satisfy the CCA program was estimated using market purchases that ranged from approximately 470 to 620 MW per month, depending on the monthly peak, plus a 15% reserve.

In addition to the generation charges, transmission and administrative costs were included in the LCOE. The transmission costs were included on all market purchases of $4/MWh. The cost of scheduling, billing, losses, and CAISO charges were estimated at approximately $15/MWh.

The result of utilizing these resources to satisfy CCA customer demand is a portfolio with a first-year resource cost of approximately $0.106/kWh or $106/MWh and levelized cost of $0.1372/kWh or $137/MWh. The low first-year cost is attributed to low short-term market purchases available in the current economic environment. It is unlikely that these low energy prices are sustainable as fossil fuel prices move higher and economic activity improves.

## 4.4 Scenario 3 – Out-of-City Resources to Satisfy Draft Implementation Plan

The third scenario analyzed estimates the LCOE of providing service utilizing the supply mix set forth in the CCA DIP with the exception that supply resources are based on out-of-City installations. This scenario measures the estimated annual and levelized cost of satisfying CCA consumer demand based upon a more flexible resource mix and assumes that the only in-City resources are those associated with the 107 MW in-City efficiency program. The renewable resources selected assume the least cost out-of-City wind and assumes 250 MW are procured in the first year. The scenario still assumes 51% in-state renewable resources by 2017.

The remainder of the supply resource in this mix is assumed to be comprised of various resources procured on a short or long term basis. The resources are utilized to serve the CCSF's demand which is set forth in Scenario 2 plus a 15% reserve margin. The load and market-based assumptions are identical to those presented in Scenario 2 except that resources are located out-of-City.

### 4.4.1 Conclusion – Out-of-City Resources to Satisfy Draft Implementation Plan (Secnario 3)

The specific resources utilized to meet the first-year customer demand included approximately 1 million MWh of generation from out-of-City wind facilities with an additional 3 million MWh purchased for the marketplace. The renewable component was approximately 30% through 2017. This was then increased to 51% using out-of-City wind purchased at a cost of about $86/MWh.

The result of utilizing these resources to satisfy CCA customer demand is a portfolio with a first-year resource cost of approximately $0.1024/kWh or $102/MWh and levelized cost of $0.134/kWh or $134/MWh. These costs are influenced in the short-term by low cost market purchases and pushed higher in the later years by the high level of renewable resources.

## 4.5 Scenario 4 – Out-of-City Resources to Meet 20% RPS

The fourth scenario analyzed estimates the LCOE of providing service utilizing an out-of-City supply mix and market purchases to satisfy a supply mix that complies with the current RPS. The customer demand and market purchase information was identical to that used in the two prior scenarios. The renewable component was 20% using out-of-City and other renewable resources to satisfy the standards. This scenario is presented to demonstrate how the annual and LCOE cost of a portfolio similar to PG&E's would compare in the current marketplace.

### 4.5.1 Conclusion – Out-of-City Resources to Meet 20% RPS (Scenario 4)

The result of utilizing a 20% RPS compliant portfolio to satisfy CCA customer demand results in a first-year resource cost of approximately $0.0827/kWh or $83/MWh and levelized cost of $0.109/kWh or $109/MWh. This scenario benefits dramatically from low short-term purchases that allow for pricing below two of the PG&E scenarios in the first several years of the analysis. These prices are the result of low fossil fuel prices and poor economic conditions. Therefore, it is reasonable to assume that a significant amount of short-term resources could be obtained at prices below those of PG&E's supply mix.