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PROGRESS REPORT ON RESOURCE ADEQUACY AMONG PUBLICLY OWNED LOAD-SERVING ENTITIES IN CALIFORNIA

JOINT COMMITTEE REPORT

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ABSTRACT

This is a statewide report on the status of resource adequacy conventions, protocols, and official standards as they exist throughout California among 54 publicly owned load-serving entities. This staff report was prepared following Assembly Bill 380 (Núñez, Chapter 367, Statutes of 2005), adding Sections 380 and 9620 to the Public Utilities Code. These sections give the California Energy Commission the responsibility to report, every two years as part of its *Integrated Energy Policy Report*, on what publicly owned electric utilities are doing to plan for and procure resources to meet the needs of their end-use customers.

Keywords: Resource adequacy, electricity resource plans, publicly owned load-serving entities, planning reserve margins

Executive Summary

Assembly Bill 380 (Núñez, Chapter 367, Statutes of 2005), gives the California Energy Commission the responsibility to report to the Legislature, as part of its biennial *Integrated Energy Policy Report*, on the progress of the state's 54 publicly owned load-serving entities in meeting resource adequacy by planning for and procuring adequate resources to meet the needs of their end-use customers. This document supports this reporting requirement.

These 54 publicly owned load-serving entities range in size from more than 6,100 megawatts (MW) to less than 1 MW in annual peak load. The sum of their non-coincident annual peak loads in 2006 was 18,921 MW, in contrast to 47,119 MW in aggregate load for the state's investor-owned utilities. The 54 publicly owned load-serving entities are located in 9 of the state's 10 control areas, four of which are administered by a publicly owned load-serving entity.

Resource adequacy requirements specify the amount of generating capacity that a load-serving entity[1] must have under its control, through ownership or contract, to ensure reliable service. This quantity is usually expressed as an amount of capacity (megawatts) in excess of peak load obligations, and is called a "planning reserve margin." Historically, these requirements have not been directly imposed on the state's load-serving entities. By introducing a class of wholesale generators without the obligation to serve loads, deregulation of the electricity sector in the 1990s increased the likelihood of periodic shortages in generation capacity. Resource adequacy requirements are, in part, a mechanism to ensure that sufficient capacity exists and is available to the control area operators responsible for administering the transmission grid.

Only the load-serving entities in the California Independent System Operator's control area are subject to formal resource adequacy requirements. These requirements are summarized in Chapter 3. Load-serving entities in this control area that are under the California Public Utilities Commission's jurisdiction, which include the state's investor-owned utilities and energy service providers, must adhere to a specific set of procurement and reporting requirements set forth by the California Public Utilities Commission and codified in the California Independent System Operator tariff. These detailed requirements include counting conventions for generation capacity, forward procurement obligations, and local and zonal capacity requirements.

Publicly owned load-serving entities in the California Independent System Operator's control area (36 of the state's 54 publicly owned load-serving entities) are also subject to tariff provisions relating to resource adequacy proposed in March 2006;

[1] A load-serving entity has obligations to provide electricity to end-use customers and includes utilities, both investor-owned and publicly owned, energy service providers, and community choice aggregators. The term came into being with the creation of "non-utility" providers of retail electric service following the deregulation of the electricity sector in California.

but, under a ruling by the Federal Energy Regulatory Commission in May 2006, they do have latitude as to how they comply with the requirements. This latitude extends to their choices of planning reserve margins, counting conventions for qualifying capacity, and non-coincident peak demand forecasts and method and coincidence adjustment. The remaining 18 publicly owned load-serving entities, which are not located in the California Independent System Operator control area, are not subject to formal resource adequacy requirements.

Thirteen of the state's 16 largest publicly owned load-serving entities submitted 10-year resource plans to the California Energy Commission for this report. Based upon aggregate data for 12 of these load-serving entities, those with annual peak loads greater than 200 MW appear to have adequate resources. In 2008, these utilities have existing resources totaling 116 percent of their aggregate non-coincident peak loads. Capacity from utility-owned generation equals 97 percent of their aggregate loads, while long-term contracts and demand-side resources equal 22 percent and 5 percent, respectively. The corresponding value in 2012 is 113 percent. One of the remaining three load-serving entities, the California Department of Water Resources, has generation and demand-side resources under its control equal to 204 percent of its forecasted coincident peak demand.

All publicly owned load-serving entities submitted narratives on their resource adequacy protocols and policies in support of this report, as well as detailed information on other aspects of their operations and planning. Chapters 4 - 6 contain summaries of these submittals. They demonstrate the load-serving entities' diversity in the specifics of their resource adequacy policies including size, the nature of their load obligations, generation and transmission assets, and their relationships with other entities including energy suppliers, transmission providers, control area operators, and other load-serving entities.

Assembly Bill 380 mandates the ongoing reporting of the progress of individual publicly owned load-serving entities toward resource adequacy as part of the *Independent Energy Policy Report*. There is also additional information that should be collected and summarized for the next reporting cycle. This relates to the relationship between the control area operators and load-serving entities outside the California Independent System Operator's control area, the manner in which local reliability and transmission constraints are assessed in these control areas, and planning activities by smaller publicly owned load-serving entities over time horizons longer than one or two years.

CHAPTER 1: Introduction

Assembly Bill 380 (Núñez, Chapter 367, Statutes of 2005), (AB 380) gives the California Energy Commission (Energy Commission) the responsibility of reporting to the Legislature, as part of its biennial *Integrated Energy Policy Report (IEPR*), on the progress of the state's 54 publicly owned electric utilities toward meeting resource adequacy by planning for and procuring adequate resources to meet the needs of their end-use customers. This document supports this reporting requirement.

Background

Resource adequacy requirements specify the amount of generation capacity that a load-serving entity (LSE)[2] must have under its control through either ownership or contract, to ensure reliable service to its end-use customers.[3] Before the deregulation of California's electricity sector, there was no need to impose such requirements on the state's investor-owned (IOU) or publicly owned utilities (POU). In their capacities as control area operators, the state's large utilities were required to meet operating reliability standards (with reserves equal to 5 to 7 percent of daily forecasted peak loads). These standards were imposed by the Western Electricity Coordinating Council (WECC), the regional reliability body for the western states. In addition, California's large utilities voluntarily established planning reserve criteria, which resulted in procurement of capacity roughly equal to 115 - 117 percent of their forecasted annual peak loads. As is the case today, the acquisition of resources by investor-owned utilities was subject to approval by the California Public Utilities Commission (CPUC). Publicly owned utilities, with the approval of their governing authorities, either procured equivalent amounts or negotiated contracts with other utilities to meet their load obligations.

The deregulation of the electricity sector in California in the 1990s was accompanied by the appearance of merchant generators and a concurrent substantial rise in the share of wholesale energy sold through power marketers. These developments had two important implications. First, in creating a class of generators without the legal obligation to serve customer load, the construction and retirement of generation facilities could no longer be realistically forecasted, much less controlled, thereby creating the potential of periodic capacity shortages. Second, an increasing share of wholesale energy transactions involved sellers that did not own generation or even necessarily have the rights to capacity for the delivery period specified in the contract; this raised the possibility that, when delivery was required, the seller would be unable able to find a source of energy to fill it.

[2] A load-serving entity has obligations to provide electricity to end-use customers and includes utilities, both investor-owned and publicly owned, energy service providers (ESPs), and community choice aggregators (CCAs). The term, also used in AB 380, came into being with the creation of "non-utility" providers of retail electric service upon the deregulation of the electricity sector in California.
[3] The purpose and structure of resource adequacy requirements is discussed in detail in Chapter 2.

In response to these uncertainties, the CPUC imposed resource adequacy requirements on the LSEs under its jurisdiction: the state's IOUs and energy service providers (ESPs). The CPUC developed these requirements, which continue to evolve, in consultation with the California Independent System Operator (California ISO). In March 2006, the California ISO proposed a set of tariff revisions under the Interim Reliability Requirements Program (IRRP), which included a set of resource adequacy requirements for the 36 non-CPUC jurisdictional, publicly owned LSEs in the control area. In May 2006, the Federal Energy Regulatory Commission (FERC) approved, with modifications, these tariff revisions. As a result, publicly owned LSEs in the California ISO control area must now meet basic requirements related to resource adequacy and reporting but have been granted more latitude than their CPUC-jurisdictional counterparts as to how they meet those requirements. There are 18 publicly owned LSEs outside the California ISO control area that not subject to formal requirements.

Publicly Owned Load-Serving Entities

There are 54 publicly owned LSEs in the state, including 31 municipalities, 4 municipal utility districts, 2 public utility districts, 5 irrigation districts, 4 rural cooperatives, and 2 joint power authorities (that include one or more of these agencies). The category also includes a community aggregator,[4] a resort improvement district, and two utilities owned by Native American tribes. The service territories of these LSEs, along with those of the IOUs, are presented in **Figure 1**.[5]

In 2006, the sum of these individual 54 LSE non-coincident peak loads totaled 18,921 megawatts (MW) as shown in Appendix Table A-1. The size ranges from 6,165 MW to less than 1 MW. In comparison, the sum of the non-coincident peak loads of California's seven IOUs, listed in Appendix Table A-2, was 47,119 MW. Appendix Table A-3 shows that the 20 largest LSEs with annual peak loads over 200 MW account for 98 percent of all non-coincident peak loads in the state. The 12 smallest LSEs of all types, while interesting in their uniqueness and diversity, account for only 0.07 percent of that statewide total. The 25 smallest LSEs account for 0.53 percent of the statewide total.

[4] The city of Cerritos established by statute, a community aggregator is distinct from a "community choice aggregator," an entity that is under the jurisdiction of the California Public Utilities Commission (CPUC).

[5] The seven IOUs in California are Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), PacifiCorp, Sierra Pacific Resources, Bear Valley Electric, and Mountain Utilities. A map of the service territories of California's investor-owned electric utilities can be found on the Energy Commission website; see [http://www.energy.ca.gov/maps/ELECTRIC_INVESTOR_OWNED_UTILITIES.PDF]. The LSEs without a designated service area on Figure 1 are Western, DWR, Power & Water Resources Pooling Authority, and Eastside Power Authority.

Figure 1. California Electric Utility Service Areas

Source: California Energy Commission, Cartography Office, September 2007

The state's 54 publicly owned LSEs are located in 9 of 10 "balancing authority areas," commonly known as control areas. Five of these control areas have a footprint entirely (or almost entirely) within the state, four of which are operated by publicly owned LSEs. As noted earlier, 36 of these 54 publicly owned entities serve or meet loads in the California ISO control area. Three small publicly owned LSEs serve loads in multiple states: Surprise Valley (in California, Oregon, and Nevada), Valley Electric (in Nevada and California), and Aha Macav (in Arizona, Nevada, and California).

Other Governmental Entities

This report includes resource adequacy information about two governmental agencies that do not meet AB 380's definition of a local publicly owned electric utility or an LSE. These two entities have project loads and have acquired generating resources to serve those loads, but they have no obligation to serve other end-use customers.

The Metropolitan Water District of Southern California (MWD) provided information on resource adequacy considerations and contract arrangements for its Colorado River Aqueduct (CRA) load. Southern California Edison (SCE) serves as the scheduling coordinator for MWD, and SCE includes MWD's CRA pumping load in its aggregated resource adequacy submittals. Therefore, MWD is discussed in this report as an end-user, and its peak pumping loads are counted with those of SCE in the appendix tables to avoid double counting.

The California Department of Water Resources (DWR) is responsible for the operation and maintenance of the State Water Project (SWP). The SWP does not fall within the definition of a publicly owned utility (POU). Further, Assembly Bill 380 expressly exempts SWP's wholesale pump loads from the definition of a load-serving entity (LSE). Because of DWR's role as steward for the SWP, which constitutes a public services infrastructure for flood control, local assistance, water supply, environmental mitigation, and electricity generation, the DWR SWP is included in this report for a more complete picture of how resource adequacy obligations are being met by public entities. DWR serves as its own scheduling coordinator at the California ISO for the SWP. DWR provides information to the California ISO and the Energy Commission on its resource adequacy protocols and planning considerations to meet its own project loads.

The report also includes information provided by the Western Area Power Administration (Western) on resource adequacy agreements and protocols on forecast customer loads. For organizational simplicity, and for a more complete inventory of resource adequacy responsibilities by public entities with load obligations, DWR and Western are included throughout this report in the category of publicly owned load-serving entities. A recent FERC decision has affirmed that for federal purposes, DWR and Western both must meet the resource adequacy filing requirements that have been developed for LSEs[6]

Report Outline

Chapter 2 provides a brief definition and summary of the purpose of resource adequacy requirements and how they relate to reliability and operating reliability standards. These relationships are important because these standards are often used as the basis for determining an "adequate" amount of generation. They are also important because AB 380 mandates the use of any resource adequacy requirement developed by the WECC, which has historically focused on operating reliability standards.

Chapter 3 provides an overview of the comprehensive resource adequacy program that applies to all LSEs in the California ISO control area. Most of this regulatory program has been developed by the CPUC for the LSEs under its jurisdiction to stimulate new investments and improve reliability, both locally and throughout the California ISO control area. As noted above, much of this program, including its reporting requirements, has been incorporated in FERC-approved tariff sheets that now apply to publicly owned LSEs.

Since no other control area has developed a comparable set of resource adequacy requirements, there is a tendency to view CPUC and California ISO programs for resource adequacy as the benchmark by which to judge other control areas. This chapter provides information on progress to date.

Chapters 4 and 5 present a summary of resource adequacy protocols, policies, planning reserve margins, and procurement activities of every publicly owned LSE in California. A majority of these LSEs, both inside and outside the California ISO control area, have adopted formal resource adequacy policies through their governing boards and city councils. Nearly all LSEs have established resource adequacy protocols that guide planning, procurement, scheduling, and commitment of resources that ensure reliable electric service. Chapter 4 begins with a summary of the aggregate loads and resources of California's large and mid-size publicly owned LSEs (those with a peak load of 200 MW or more). It is followed by a summary of resource adequacy protocols, policies, planning reserve margins, and

[6] "Given that the State Water Project is the CAISO's single largest transmission user representing five percent of load, we agree with the CAISO that exempting the State Water Project from resource adequacy requirements would significantly hamper the CAISO's ability to reliably operate the grid, and find that such a result would be unjust and unreasonable. Therefore, we find the State Water Project is a LSE and subject to the resource adequacy requirements of the MRTU Tariff. We also find that the State Water Project is its own Local Regulatory Authority and therefore can establish its own planning reserve margin and determine how it will meet its reserve requirements, including counting curtailable load towards resource adequacy requirements." (FERC decision in Docket No. ER06-615-000, *et al*., ordering paragraph 1138, September 21, 2007, published at [http://www.ferc.gov/whats-new/comm-meet/092106/E-1.pdf]).

procurement activities of the individual LSEs. Using data from 10-year resource plans submitted to the Energy Commission, the figures and tables illustrate how each POU will use a mix of both existing and planned capacity resources to meet annual peak demand through 2016. Chapter 5 covers the state's publicly owned LSEs with annual peak loads of 200 MW or less.

In this project, a few entities were identified that do not have a load-serving obligation requiring procurement plans for electricity resources. Chapter 6 presents background information on these non-LSEs, which include four end-users, two end-use aggregators, and two entities organizing to become LSEs in the near future (an existing irrigation district and a newly formed community choice aggregator).

Chapter 7 provides a discussion of areas in which more information needs to be gathered. The mechanisms by which control area operators outside the California ISO control area obtain an adequate amount of capacity also need to be better understood, as do the manner in which local reliability and transmission issues are assessed and managed in these control areas. AB 380 requires that the Energy Commission report on the progress of the state's publicly owned LSEs on an ongoing basis; therefore the time horizon over which smaller LSEs evaluate and report their procurement decisions and resource planning policies is also of interest.

CHAPTER 2: Resource Adequacy and Resource Adequacy Requirements

Resource adequacy requirements specify the amount of generation capacity that an LSE must have under its control through either ownership or contract. As these requirements are meant to ensure that the electricity system operates reliably to meet customer demand, a definition of “reliability” is necessary. This chapter presents a discussion of electric reliability, how reliability standards are set, and how reliability and resource adequacy are related to one another.

Resource Adequacy and Reliability

Reliability is traditionally measured in terms of the frequency, duration, and/or quantity of involuntary curtailment of load; that is, how often and to what extent customers experience power outages. For example, a commonly used reliability standard is that power outages due to supply shortages occur in the system only one day in every 10 years. Other reliability standards measure the volume of “unserved energy” in the system expected during a particular year. Still other standards of reliability set limits on the frequency and/or duration of outages from all causes as experienced by customers on a distribution circuit.

The choice of a reliability standard reflects the value of uninterrupted service: the more costly an outage, the more customers are willing to pay for the additional capacity needed to prevent it. As will be evident from the discussion on resource adequacy among the state’s individual LSEs in this report, both those entities and those that impose resource adequacy requirements upon them[7] may choose from a myriad of possible reliability standards. No standard, much less a single specific standard, is required by either federal or state law.

The reliability standard is typically translated into a planning reserve margin (PRM) for purposes of establishing resource adequacy requirements. The PRM is the amount of generation capacity and interruptible demand under the control of the LSE that exceeds its forecasted peak demand obligations; it is most often expressed as a percentage of the latter.[8] A commonly used PRM in LSE resource planning is 15 - 17 percent, which is often assumed to provide the “one day in 10 years” level of reliability described above. The relationship between the PRM and “loss of load probability” depends upon the LSE’s portfolio of resources, transmission constraints that hamper delivery of energy to customers, and assumptions regarding the availability of energy from resources owned and operated by other parties. These

[7] Those LSEs subject to the authority of the CPUC may be subject to a resource adequacy requirement based on one standard, while an LSE not under the jurisdiction of the CPUC can select a standard of its own choosing. However, those LSEs within the California ISO control area must each have a standard that meets the ISO tariff requirements for resource adequacy.

[8] For example, an LSE with a forecasted peak demand of 200 MW and 235 MW of generation under its control has a PRM of 35 MW or 17.5 percent ([235-200]/200).

factors make it difficult to estimate with any precision. Nevertheless, resource adequacy requirements are expressed in terms of the PRM that an LSE is required to maintain.

Control Areas and Operating Reliability

While LSEs commit and dispatch generation under their control to meet their load obligations, they are not solely responsible for ensuring reliable service on a real-time basis. It is the responsibility of the control area operator to ensure that real-time demand is balanced by supply plus operating reserves in a way that ensures the stability of the transmission grid; these operators are ultimately responsible for "reliability." A control area is a portion of the transmission grid over which a single entity has "balancing authority." Balancing requires dispatching generating units to balance supply and demand within the control area in real time; control area operators respond to changes in demand and supply, including the sudden loss of generation and/or transmission, to continually maintain the stability of the transmission grid. Failure to do so constitutes failure to meet the operating reliability standards required by the North American Electric Reliability Corporation (NERC), and can result in financial penalties. Though there are no legislated reliability standards per se, there are established operating reliability standards that control area operators must meet.

There are 10 control areas in California; as a rule, several LSEs provide electricity to meet the load in each control area. This document is primarily concerned with four of these control areas: the California ISO, the Sacramento Municipal Utility District (SMUD), the Los Angeles Department of Water and Power (LADWP), and Turlock Irrigation District (TID).[9] In three of these areas, the control area operator is also an LSE with control of its own generation.

As balancing authorities, control area operators have three basic alternatives to interrupting load during times of supply shortages:

1. An LSE that operates a control area can use the commitment and dispatch of its own generation resources.
2. The control area can secure effective control of the dispatch of generation from other LSEs in the control area through either formal or informal agreements.
3. The control area can purchase additional energy from merchant generators, power marketers, or from organized energy markets.

[9] Four of the remaining five are small portions of larger control areas that are predominantly in Nevada, Arizona and Oregon. The other control area, Imperial Irrigation District (IID) contains only one LSE.

The California ISO is not an LSE and does not own generation. Its resource adequacy program therefore specifies that it control the dispatch of a share of the generation procured by the LSEs in its control area. The California ISO also has “backup procurement authority” to procure generation on its own initiative for reliability during specified circumstances.

As defined by NERC, a “balancing authority” is the responsible entity that integrates LSE resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time.

Resource Adequacy and Forward Procurement

Resource adequacy requirements may not only dictate the PRM that an LSE maintain and mandate control of generation capacity to the control area operator. Those requirements may also specify the amount of capacity that an LSE must procure before real time operation: one month ahead, one year ahead, or five years ahead, for example. As discussed in the next chapter, the resource adequacy program of the California ISO has these forward requirements. Forward requirements of one year or less are largely designed to assure the control area operator that there are sufficient resources under LSE control to meet loads. Three-year and longer forward requirements, not currently imposed by the California ISO, are intended to stimulate development of new generation capacity.

The resource adequacy program designed by the CPUC for the LSEs under its jurisdiction is designed to accomplish the additional objectives of a reliable, economical, and fairly structured system. As set forth in AB 380, CPUC works with the California ISO and LSEs under CPUC jurisdiction to achieve five additional objectives:

1. Facilitate development of new generating capacity.
2. Retain existing and needed existing generating capacity.[10]
3. Equitably allocate costs of resource adequacy generating capacity.
4. Prevent cost shifting among customer classes.
5. Minimize requirements and enforcement costs.

As discussed in more detail in Chapter 3, the CPUC’s resource adequacy program also requires that LSEs under its jurisdiction procure capacity in specific locations (California ISO-defined “local reliability areas”) to meet local reliability requirements.[11]

[10] AB 380 actually lists the first two objectives as #1. They may be two sides of the same coin. However, different proceedings tend to address one objective well, and the other objective less well, so these two objectives are listed separately here for clarity.
[11] AB 380, Section 2.

AB 380 does not define parallel practical objectives for public utility resource adequacy or for the Energy Commission. Instead, the mandate squarely placed upon each “publicly owned electric utility” is to “prudently plan for and procure resources that are adequate to meet its planning reserve margin and peak demand … [for] service to its customers.” AB 380 defines only one clear standard by which to measure adequacy: to “meet the most minimum planning reserve and reliability criteria approved by the WECC (Western Electricity Coordinating Council).” As discussed in the next section, the WECC has not established “planning reserve and reliability criteria” for LSEs; it has only established such criteria for control area operators. However, those LSEs within the California ISO control area are subject to the ISO’s criteria as discussed in Chapter 3.

NERC, WECC, and Resource Adequacy Standards

AB 380 requires that California’s publicly owned electric utilities meet planning reserve criteria mandated by the WECC; Section 2 of the legislation adds Section 9620(b) to the Public Utilities Code:

> Each local publicly owned electric utility serving end-use customers shall, at a minimum, meet the most recent minimum planning reserve and reliability criteria approved by the Board of Trustees of the Western Systems Coordinating Council or the Western Electricity Coordinating Council.

After spending two years developing a resource adequacy program for the Western Interconnection, it appears that the WECC does not intend for the program to lead to mandatory forward commitment obligations for LSEs. The proposals to date emphasize assessment protocols, guidelines, and possible benchmarks that would provide information to the industry about the state of readiness of various parts of the Western Interconnection, perhaps down to individual control areas, to reliably serve customer load. It therefore appears unlikely that the WECC will adopt a resource adequacy standard that would translate directly into a procurement obligation for either POUs or other LSEs. Written comments received in this proceeding from SMUD support this assessment:

> NERC (North American Electric Reliability Council) or WECC will only focus on requirements for reliably serving load, including how to plan in the long-term for meeting load. Although reliability is related to Resource Adequacy, Resource Adequacy (when and which resources to procure) is the purview of the state and local regulatory bodies, so SMUD doesn’t expect NERC to enact explicit Resource Adequacy standards.” (SMUD, May 31, 2007)

Participants in the WECC Loads and Resources Subcommittee believe that the WECC and NERC will remain focused on reliably serving load. These two organizations recognize that state and local regulatory bodies have the primary responsibility to determine when and how resources are procured. While the WECC does not have a formal requirement for a planning reserve margin, the power supply assessment studies conducted by the WECC have used a 15 percent planning reserve margin to determine if an area within the Western Interconnection is likely to have adequate resources. The current power supply assessment, however, is using a “building blocks” approach that is specific to each control area instead of the traditional 15 percent rule-of-thumb planning reserve margin.

CHAPTER 3: Resource Adequacy Requirements for LSEs in the California ISO Control Area

Only one control area has a comprehensive set of formal resource adequacy requirements: the California ISO Balancing Authority Area. This resource adequacy program has been developed over the past five years by the CPUC[12], in collaboration with the California ISO, and with the support of the Energy Commission and the active participation of other stakeholders. It was initially developed as a procurement obligation for investor-owned utilities (IOUs) and energy service providers (ESPs) that fall under CPUC jurisdiction. In 2006, through the California ISO's Interim Reliability Requirements Program, the program was extended, strengthened, and adapted to apply to all publicly owned LSEs in the California ISO control area.

Because 36 of California's 54 publicly owned LSEs are located in the California ISO control area, an understanding of the ISO's resource adequacy protocols and requirements is necessary to illuminate the many issues and concerns relating to the resource adequacy of publicly owned LSEs. These 36 LSEs are identified individually in Appendix Table A-2. As shown in Appendix Table A-4, two-thirds of the 54 LSEs are publicly owned LSEs, but 36 LSEs serve slightly less than 10 percent of peak loads in the control area. Only five publicly owned LSEs in the California ISO control area have peak loads greater than 200 MW: the California Department of Water Resources, Silicon Valley Power, Riverside, Anaheim, and Pasadena. There are 4 IOUs and 14 ESPs serving load in the California ISO control area. These CPUC-jurisdictional entities serve about 90 percent of peak loads in the control area, as shown in Appendix Table A-4.

The CPUC's resource adequacy program has two primary and related purposes. The first is to assure reliability by making adequate capacity available to the California ISO to serve the aggregate of control area load and to meet system, zonal, and local reliability needs. Part of this effort entails contracting with sufficient generation to ensure that the retirement of uneconomic facilities does not threaten system or local reliability. The second purpose is to spur investment in new capacity. The regulatory foundation of this program as developed by the CPUC has been adopted and implemented in large measure by the California ISO and incorporated in federally approved rules that regulate wholesale competitive energy markets in California.

The Interim Reliability Requirements Program

On March 13, 2006, the California ISO proposed a set of tariff revisions under the Interim Reliability Requirements Program (IRRP). On May 12, 2006, this proposal

[12] See CPUC decisions D.04-01-050, D.04-10-035, D.05-10-042, D.06-06-064, and D.06-07-031.

was approved by FERC, with minor modifications. The California ISO published revised tariff sheets on June 12, 2006.

In the May 2006 FERC order that approved the California ISO tariff sheets on resource adequacy, FERC established some reporting obligations on publicly owned LSEs that are identical to those for CPUC-jurisdictional LSEs. For example, "Other than for good cause, the form of the Resource Adequacy Plan and the date for submission for the CPUC Load-Serving Entities and the Non-CPUC Load-Serving Entities should be identical" (section 40.2.1).

Annual and Monthly Resource Adequacy Plans

The first impact on publicly owned LSEs came soon after the May 12, 2006, FERC order. LSEs were required to file, through their scheduling coordinators, monthly resource adequacy plans. The first one was due by May 25, 2006, for July 2006. Thereafter, for every month of the year, each LSE is required to file a monthly resource adequacy plan by the last calendar business day two months in advance -- for example, by March 31 for the month of May for each year.

LSEs are also required to file an annual resource adequacy plan by October 25 of each year. The annual plan covers May through September of the following year. Both the monthly and annual filings must include a monthly peak-hour demand forecast, along with a showing of how this demand will be met by named capacity resources including utility-owned generation, resources under contract, and demand-side programs. Once named in a monthly or annual plan, these resources are obligated to be available to the California ISO, with exceptions only for forced outages.

For CPUC-jurisdictional LSEs, annual and monthly capacity obligations are based upon LSE non-coincident demand forecasts, which are reviewed by the Energy Commission for plausibility and basic forecast assumptions including load migration. An adjustment is applied by the Energy Commission to yield a forecast of equivalent coincident peak demand.[13] Then the aggregate of LSE coincident peak forecasts is adjusted to match Energy Commission TAC-area forecasts within 1 percent tolerance. The final Energy Commission coincident peak load forecasts for IOUs and ESPs includes allocations of DR resources that can be used to satisfy their resource adequacy filing requirements with the CPUC and at the California ISO.

[13] An LSE's "actual coincident peak load" is its demand that is being served in the hour in which the load of a larger entity to which it contributes (for example, the control area in which it resides) is at its maximum. An LSE's non-coincident peak load is the LSE's highest hourly load during an entire month or year, independent of loads in the larger entity. Non-coincident peak is larger than coincident peak unless the LSE's non-coincident peak load occurs at the same time as that of the larger area, in which case the two values are equal.

Local Regulatory Authorities

The FERC order also established specific legal responsibilities for the scheduling coordinator and the local regulatory authority for each LSE. For publicly owned LSEs in the California ISO Balancing Authority Area, governing boards and city councils are local regulatory authorities. For all active IOUs, ESPs, and community choice aggregators (CCAs), according to the California ISO tariff, the CPUC is the designated local regulatory authority. Local regulatory authorities for rural electric cooperatives are neither entirely clear nor well established. Rural cooperatives are publicly owned and locally governed, but these non-profit corporations fall in some respects under CPUC jurisdiction.

Each designated local regulatory authority has responsibilities and discretion in three areas of the resource adequacy program. The first is setting the planning reserve margin (PRM) for the LSE. The second is setting performance and availability criteria for each type of generation and demand-side resource (thereby establishing the amount of capacity for each to be credited to a resource adequacy requirement or "qualifying capacity"), in addition to setting limits on how resources with limited availability can be aggregated in an LSE's portfolio. The third responsibility of each local regulatory authority is to provide a demand forecast and to establish a forecasting method. If a local regulatory authority does not adopt a specific PRM or qualifying capacity criterion, the LSE must use a 15 percent PRM and the default qualifying capacity criteria specified in the IRRP.

For the monthly resource adequacy plans, each CPUC-jurisdictional LSE must demonstrate procurement sufficient to meet 100 percent of its forecasted peak monthly *coincident* demand, plus a 15 percent PRM. For the annual resource adequacy plans, each CPUC-jurisdictional LSE must demonstrate procurement sufficient to meet 90 percent of its forecast summer month peak coincident demand, plus a 15 percent planning reserve margin. This equals 103.5 percent of the forecast monthly peak for each IOU and ESP.

California ISO Verifications, Studies, and Allocations

The California ISO is authorized to verify the qualifying capacity of all resources listed in a resource adequacy plan. It is responsible for determining the net qualifying capacity of a generating unit through an annual deliverability analysis (Section 40.5.2.1). For the interim resource adequacy program, the California ISO is also required by tariff to estimate the import capacity of transmission paths and branch groups and allocate that capacity, to both LSEs and other market participants, according to a complex formula.

In general, the California ISO has been able to allocate import capacity by first honoring, as much as possible, existing transmission contracts and encumbrances, then distributing the remaining import capacity among CPUC and non-CPUC jurisdictional entities using load share ratios (Section 40.5.2.2) developed by the Energy Commission Demand Analysis Office staff.

The Obligation to Remain Available

With certain exceptions, all resource adequacy resources named by LSEs in their annual and month-ahead filings must be available to serve aggregate load in the control area. This obligation to offer capacity begins with the day-ahead list of resources filed by the LSE's scheduling coordinator. If the capacity resource is not scheduled a day ahead, the LSE must offer to sell to the California ISO's real time market for imbalance energy in all hours (Section 40.6A.4). Exceptions are made for resources participating in the California ISO's ancillary services markets.

Wind and solar resources satisfy this scheduling obligation through enrollment in the California ISO's Participating Intermittent Resources Program, since at any given moment a wind resource may produce more or less energy than predicted in its final hour-ahead schedule. Hydroelectric facilities and qualifying facilities are exempt from the general requirement to be available to the California ISO. Also exempt are resources serving load in areas covered by Metered Subsystem agreements.

Metered Subsystem Reporting Obligations

A few publicly owned LSEs have contractual integration agreements with the California ISO that predate the Interim Reliability Requirements Program (IRRP) tariff revisions. Under these Metered Subsystem (MSS) agreements, each LSE provides annual filings to the California ISO about peak loads and available generation that serve loads in its exclusive service area. Anaheim, Vernon, Silicon Valley Power, and Plumas-Sierra all have MSS agreements in place. The Northern California Power Authority (NCPA) has a Metered Subsystem Aggregator (MSS-A) agreement that covers nine of the 10 LSEs in its power pool (not including Plumas-Sierra).

Under the IRRP tariff, LSEs with MSS agreements are not required to file annual or monthly resource plans on the standard Excel templates adopted by both the CPUC and the California ISO. Instead, the California ISO uses MSS reporting terms and standards to obtain "equivalent information" (Sections 40.2.1, 40.2.2, and 40.6). For LSEs with MSS agreements, generating unit outages must be coordinated and approved by the California ISO. If the LSE demonstrates to the California ISO that it has its own peaking resources to meet forecast demand (plus a 15 percent planning reserve margin), the LSE is exempt from certain reliability charges.

These agreements generally give the LSE some autonomy – within a specified range – to follow its load-using generation that would only become available to the California ISO, on a mandatory basis, during declared emergency conditions. An LSE with an MSS agreement is not obligated to participate in rotating outages caused by a resource deficiency unless emergency conditions threaten grid reliability.

LSEs with an MSS agreement have significant financial incentives to closely match their loads and resources during their scheduling and real-time operations. These MSS agreements typically impose costly penalties for overscheduling or underscheduling beyond a 3 percent margin of error. In these ways MSS agreements resemble the interconnection agreements between POUs and PG&E that expired on August 31, 2002. Terms of MSS agreements typically limit cost components of the grid management charge (GMC) billed to the LSE for uninstructed deviations, energy transmission services, and intrazonal congestion.

Qualifying Capacity: Default Counting Conventions

The IRRP tariff established default qualifying capacity criteria in cases where a local regulatory authority does not establish its own criteria. The CPUC has adopted these default criteria for all the ESPs and large IOUs under its jurisdiction. Most publicly owned LSEs in the California ISO control area have adopted most of these counting conventions, except as noted in Chapters 4 and 5.

The default qualifying capacity for a nuclear or thermal generating unit is considered to be net dependable capacity as defined by NERC and the Generating Availability Data System (GADS) information. Several LSEs reference GADS in their resource adequacy policies.

As a default criterion, firm energy contracts with liquidated damages (LD) provisions are eligible as qualifying capacity only until the end of 2008. In 2006, only 75 percent of an LSE's portfolio could be supplied by LD contracts. In 2007, the limit is 50 percent, and in 2008 the limit will be 25 percent. The local regulatory authorities for several publicly owned LSEs have specifically adopted criteria treating all LD contracts as qualifying capacity. For example, the City of Industry uses LD contracts to serve 100 percent its 6.0 MW annual peak load, with dispatchable demand response resources serving its 15 percent planning reserve margin. Western has adopted criteria treating its LD contracts as qualifying capacity, including supplies from Corral Energy and PG&E (Western may purchase firm energy to supply U.S. Department of Energy facilities such as NASA Ames or to ensure adequate resources in January at times when pumping loads exceed hydroelectric generation from the Central Valley Project).

For pond or pumped storage hydroelectric units, the qualifying capacity is equal to GADS-defined dependable capacity, minus a "derate" for variable head for an "average dry year reservoir" level. All run-of-river hydro units use GADS-defined dependable capacity minus a derate for average dry year flows. An "average dry year" reflects a one-in-five year scenario, such as the fourth driest year in the last 20 years on record. (Modesto and Turlock have adopted criteria for hydro capacity that rely on actual snowpack measurements, runoff forecasts, and predicted reservoir levels for New Don Pedro and other resources.) Rather than rely on historical data and one-in-five probabilities, Western uses a rolling 12-month average of forecast capacity for its Central Valley Project facilities.

Wind and solar units must use a three-year rolling average of hourly output during the hours of noon to 6 p.m. in any particular month. The CPUC compared this criterion to actual hourly generation during the five peak days of the July 2006 heat wave. During the hours of 3 p.m. to 4 p.m. on those five days, actual wind generation was about 48 percent of the net qualifying capacity, as established by this criterion.

Demand response resources, called “participating load resources” in the tariff, must be available at least 48 hours in a year to be counted. Their qualifying capacity is determined by the average reduction in demand (on a per-dispatch basis) over a three-year period.

Resource Adequacy Under Market Redesign and Technology Upgrade (MRTU)

Scheduling coordinators for all load-serving entities in the California ISO will have highly specific filing requirements under MRTU. On September 21, 2007, FERC approved much of revised tariff sheets that were submitted by the California ISO on August 3, 2007.

> As noted in the IRRP Order, we reiterate that, in order to ensure short-term reliability and prudent operation of the grid, it is critical that the CAISO collect annual and monthly resource adequacy information from each Scheduling Coordinator representing an LSE in the CAISO Control Area. [14]

FERC also found it reasonable to require standard reporting templates, and to use CPUC templates as a reasonable starting point. In this ruling, FERC addressed some concerns about the “confluence” of state and federal jurisdiction, stating

> … we recognize the states’ historical role in ensuring resource adequacy. The fact that we must, to fulfill our statutory responsibilities, be assured of a workable approach to resource adequacy does not mean that we should ignore the states’ traditional role in this area. Rather, we can fulfill our jurisdictional responsibilities while also respecting the states’ traditional role in this area. As a general matter, it is our responsibility to ensure that a workable resource adequacy requirement exists in a market such as that operated by the CAISO.

[14] FERC Order Conditionally Accepting Conditionally Accepting the California ISO’s Electric Tariff Filing to Reflect MRTU, Docket ER06-615-000, Ordering paragraph 1324, [http://www.ferc.gov/whats-new/comm-meet/092106/E-1.pdf]

> This does not mean that we must determine all the elements of such a program in the first instance. Rather, we can, in appropriate circumstances, defer to state and Local Regulatory Authorities to set those requirements." (Ordering paragraph 1117)

FERC specifically rejected the California ISO proposal for a minimum 15 percent planning reserve margin that would be applied to all LSEs, unless the local regulatory authority for an LSE failed to adopt a planning reserve margin (Ordering paragraph 1153).

Pending Issues for Small CPUC-Jurisdictional LSEs

The CPUC is presently engaged in rulemaking (R.05-12-013, Phase 2, Track 3) to establish resource adequacy requirements for small and multi-jurisdictional utilities (SMJUs). The December 22, 2006 ruling and scoping memo required these LSEs to submit proposals that would refine and further develop the CPUC's Resource Adequacy Requirements Program and to comment on "whether, and if so to what extent, any of" the SMJUs "should be subject to resource adequacy program requirements that are different from those that have been adopted to date."

PacifiCorp, Sierra Pacific, Bear Valley, and Mountain Utilities provided individual proposals for customizing resource adequacy requirements for their unique physical and regulatory circumstances. These four IOUs also filed joint comments, asserting that "the Commission [CPUC] should not impose a 'one-size fits all' approach on the SMJUs by applying the same RAR template that is required of the large IOUs, Energy Service Providers and Community Choice Aggregators." (Joint comments filed May 18, 2007). These joint parties make the argument that AB 380 requires the CPUC to establish an efficient and equitable program for resource adequacy, but that "AB 380 does not mandate that the Commission [CPUC] impose the same rules on all LSEs to meet these objectives."

Bear Valley Electric Service (BVES) is the only small IOU located in the California ISO control area. It serves customers in the Big Bear Lake area of the San Bernardino Mountains, and includes a ski resort. BVES' peak demand occurs over the Christmas holiday season. During the summer months, BVES' non-coincident peak load occurs on weekends and holidays (July 4 and Labor Day), both times when coincident peak loads in the California ISO control area are low. BVES has requested that it be allowed to provide its own estimate of its California ISO coincident peak demand, since this service has not been provided for LSEs with lower than a 200 MW annual peak demand. BVES has also requested that its 15 MW LD contracts be credited as full value through 2008 and exempted from the 50 and 25 percent respective portfolio limits for those years (May 18, 2007, filing by BVES).

Mountain Utilities (MU) is off the grid in the high Sierra. MU proposes to incorporate its resource adequacy reporting program into its annual reporting requirements to the CPUC (under General Order 104). MU has 5.2 MW of generating capacity from six diesel units. MU has no transmission connection to the grid and no specific or formal reserve margin. Peak load in 2006 was 3.8 MW. When a diesel generator wears out (and its life is short), it is replaced. In practice, some diesel units can often be kept in "non-spinning reserve;" this informal approach aims to operate with a non-spinning reserve margin of 10 percent. MU proposes that a simple chart comparing annual peak loads with generating capacity for current and forecast years is sufficient for its planning purposes. MU believes that "[G]reater complexity of reporting can impose excessive costs on ratepayers without a commensurate benefit." (May 18, 2007 filing by MU).

Sierra Pacific provides retail service in northern Nevada and the Lake Tahoe area of California. Only 6 percent of its load is in California. Except for a 12 MW emergency diesel generator at Kings Beach, all its generating resources are in Nevada. Sierra Pacific claims that it has been and will continue to be resource adequate in its bi-state service territory, and that the CPUC should continue to rely upon the Public Utilities Commission of Nevada (PUCN) for regulation of its comprehensive resource planning, procurement, and resource adequacy. Sierra Pacific prepares an integrated resource plan every three years, which is submitted for approval to both the PUCN and CPUC. This coordinated plan integrates information on generation, transmission, procurement, environment, finance, renewables, and energy efficiency while ensuring that customer needs will be adequately met. In a spirit of regulatory cooperation, Sierra Pacific requests that the CPUC accept its integrated resource plan as its multi-year demonstration of resource adequacy (May 18, 2007 filing by Sierra Pacific).

PacifiCorp also requests that the CPUC accept its integrated resource planning process "as the best approach for complying with AB 380 and advancing the goals of the Commission's [CPUC] RAR [resource adequacy reporting] program." With operations in six states, PacifiCorp biennially submits an integrated resource plan to six different state commissions. PacifiCorp serves its Northern California loads entirely with systemwide resources. PacifiCorp plans "to a coincident peak-hour capacity planning reserve margin of 12 to 18 percent on a system and control area basis" (May 18, 2007 filing by PacifiCorp). With a systemwide total of 23 topology load pockets, "The planning reserve margin requirement is enforced at the topology load pocket level to ensure that individual load centers, as well as PacifiCorp as a whole, meet the planning reserve margin requirement." (May 18, 2007, filing by PacifiCorp)

The CPUC has also invited proposals from three rural electric cooperatives: Plumas-Sierra (part of the NCPA power pool), Surprise Valley (a full requirements customer[15] of Bonneville Power Administration [BPA]), and Anza Electric (a full requirements customer of Arizona Electric Power Cooperative). The California ISO tariff on resource adequacy defines rural electric cooperatives as local POUs, which creates

[15] Full requirements customers of BPA are LSEs for which BPA is obligated to meet all wholesale energy needs under contract or law.

some confusion as to which local regulatory authority is responsible for establishing resource adequacy protocols (under AB 380).

CHAPTER 4: Resource Adequacy Protocols of Large and Mid-Sized Publicly Owned LSEs

This chapter provides a detailed description of the resource adequacy protocols and adopted policies and procurement activities of California's large- and mid-sized POUs. Large POUs have peak loads of 1,000 MW or more, and mid-sized have peak loads of between 200 MW and 1,000 MW. Most of these entities provided detailed 10-year resource plans to the Energy Commission in early 2007, and all of them provided narrative descriptions of their resource adequacy protocols and policies.

Details of the peak loads and control areas for each of the state's publicly owned LSEs are included in Appendix A.

Sources and Filings on Resource Adequacy Policies

Thirteen of the state's large and mid-sized POUs provided 10-year forecasts of their capacity needs and the resources expected to meet them, as well as narrative descriptions of their resource adequacy policies. These were provided following a request for data issued in the *2007 Integrated Energy Policy Report* proceeding.[16] Two other entities of similar size – the California Department of Water Resources and the Western Area Power Administration – volunteered information about their policies, upon request. The Northern California Power Authority also provided information for its power pool.

For publicly owned LSEs with annual peak loads less than 200 MW, there was no regulatory obligation to provide the information requested by the Energy Commission for this report on resource adequacy. The small publicly owned LSEs were requested to provide this information voluntarily if it was available. These Energy Commission instructions and requests to publicly owned LSEs outlined the scope and purpose of this collaborative project.

Proposed regulations for the ongoing implementation of AB 380 were submitted to the Office of Administrative Law in early 2007. On July 2, 2007, the Office of Administrative Law approved the amendments to the Energy Commission's regulations governing the rules of practice and procedure, data collection, and the disclosure of public records. In future years, these amended regulations will facilitate a more standardized approach for the reporting of resource adequacy progress by all publicly owned LSEs.

The breadth and depth of the narratives submitted to the Energy Commission provide a wealth of information about publicly owned LSE resource adequacy

[16] Instructions for large and mid-sized POUs were adopted by the Energy Commission on January 3, 2007. See http://www.energy.ca.gov/2006publications/CEC-100-2006-002/CEC-100-2006-002-CMF.PDF

policies and their development. As examples of comprehensive yet diverse approaches to resource adequacy, the complete submittals of the Los Angeles Department of Water and Power, Anaheim Public Utilities, and the Turlock Irrigation District are contained in Appendix B.

California Publicly Owned Load-Serving Entities and Resource Adequacy

To a large extent, it appears that publicly owned LSEs in California are doing their part to provide forward contracting[17] or the procurement of utility-owned generation to serve their respective loads. **Table 1** shows that, during 2003 - 2006, California POUs brought 1,647 MW of new thermal generation online with an additional 160 MW under construction and expected to be on line in 2007. This 1,807 MW exceeds their non-coincident peak-load growth during the period.

Table 1: New Resource Construction, California POUs, 2003 – 2007

Resource Name	Owner	Status	MW	On-line Date
Woodland II	Modesto Irrigation District	Operational	80	06/06/2003
Donald Von Raesfeld	Silicon Valley Power	Operational	147	03/24/2005
Kings River	Kings River Conservation District	Operational	97	09/19/2005
Magnolia	SCPPA, operated by Burbank	Operational	328	09/22/2005
Malburg	City of Vernon	Operational	134	10/17/2005
Cosumnes Unit 1	Sacramento Municipal Utility Dist.	Operational	500	02/24/2006
Walnut	Turlock Irrigation District	Operational	250	02/28/2006
Riverside Energy Center	City of Riverside	Operational	96	06/01/2006
Ripon	Modesto Irrigation District	Operational	95	06/21/2006
Total			1,647	
Roseville Combined Cycle	Roseville Electric	Under Construction	160	November 2007
Niland Peaker	Imperial Irrigation District	Under Construction	93	June 2008
Total			253	

Source: California Energy Commission, October 2007.

In addition, projects submitted for siting approval by the cities of Vernon and Victorville are currently under review by the Energy Commission. Vernon's proposed power plant project is 943 MW, and Victorville's is 563 MW.

The 10-year resource plans described in this chapter show that large and mid-sized POUs continue to conduct periodic integrated resource planning to serve their respective native loads.

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[17] Forward contracting is an agreement to provide a specified commodity at a set price to a certain location over a period.

Supply and Demand Balances of Large and Mid-Sized Publicly Owned Utilities

This section characterizes the aggregate resources that 12 of California's large and mid-sized POUs plan to use to meet their annual peak energy needs in aggregate, as reported individually in 10-year outlooks filed with the Energy Commission in February 2007. **Figure 1** and **Table 2** indicate that, in aggregate, the state's large and mid-sized POUs have largely procured the resources they need to meet their forecasted peak loads through the end of this decade.

The 12 POUs for which data is summarized, below, represent 73 percent of the statewide aggregate of POU peak loads. The remaining four large or mid-sized publicly owned LSEs have, in aggregate, procured resources well in excess of their capacity needs for the next 10 years (see below).

Figure 1 illustrates that, in aggregate, procurement to date by the state's large and mid-sized POUs exceeds the sum of their non-coincident 1-in-2 peak demand plus a 15 percent planning reserve margin through 2011. These POUs primarily rely upon utility-owned resources[18] for capacity, referred to as "power plants" in the figure.

Table 2 indicates that the total capacity of utility-owned resources is equal to 92 percent of POU-forecasted aggregate peak load in 2008. The capacity associated with these resources increases by roughly 1,000 MW to slightly more than 13,000 MW over 2007-2016 because of the assumed construction of several plants, discussed below.

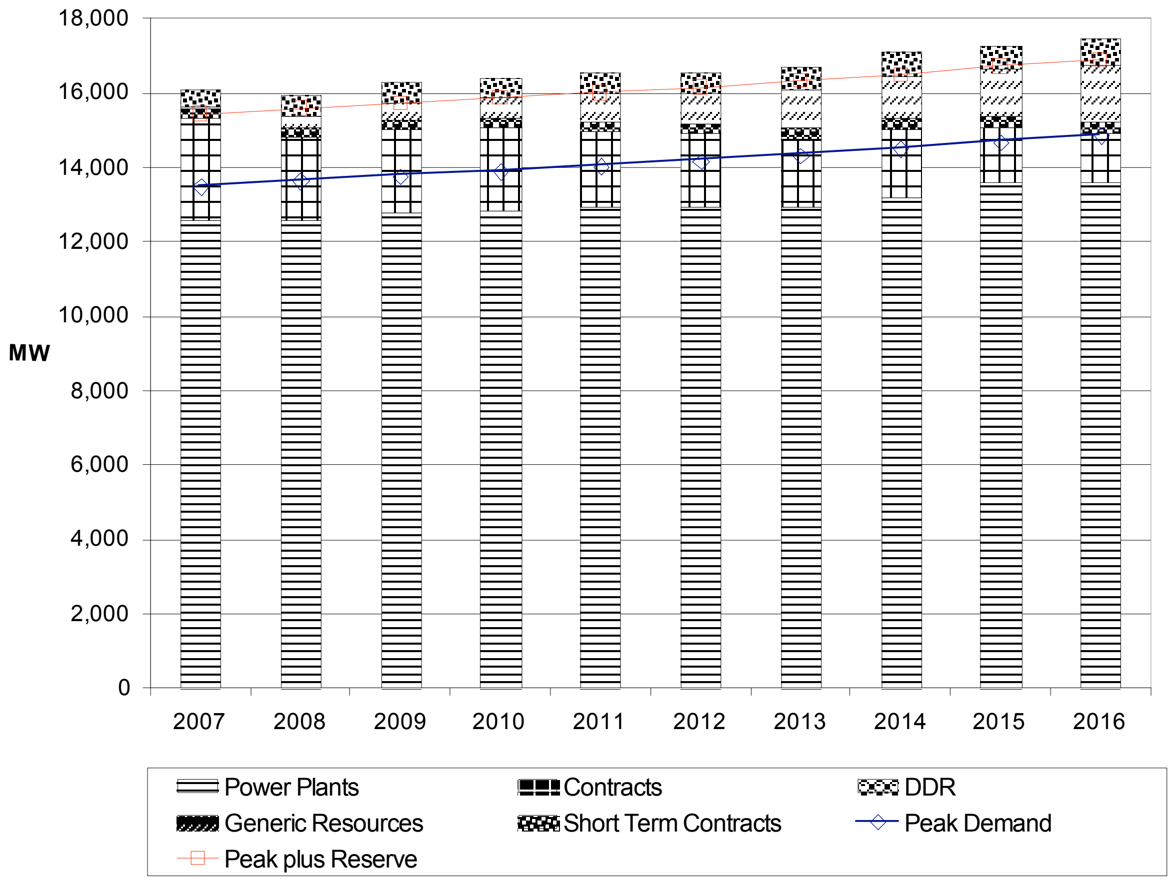
Table 2 shows that the capacity associated with long-term (longer than one year) contracts with conventional (thermal or unspecified) resources falls from 17 percent to 9 percent of forecasted aggregate peak load. Long-term renewable contracts fall from 5 percent of peak demand in 2008 to 4 percent in 2016. This reflects the expiration of existing contracts and the fact that contracts with renewable resources tend to have longer terms. "Generic resources" are also reported by several POUs. This term is used to indicate the need for additional capacity and the expectation that it will be met with new utility-owned generation. It is likely that the utilities did not uniformly interpret the meaning of "generic resource additions" in the absence of a fixed resource adequacy requirement (for example, maintaining a 15 percent PRM). These numbers, in aggregate, are probably of little value.

The values in **Table 2** are based upon aggregated non-coincident peak loads. They therefore understate the extent to which the represented POUs, in aggregate, are resource adequate. This factor applies particularly to the majority of POUs in the large and geographically diverse California ISO control area, (provided that they are *not* covered by Metered Subsystem Agreements discussed above). When coincident

[18] "Utility-owned" resources include those held by joint powers authorities and for which the utility has a long-term right to output.

peak demand is at its highest in the California ISO control area, the expected aggregate demand faced by these POUs could be 2 to 3 percent lower.

Figure 2: Aggregate Procurement, Selected California POUs[1] with Annual Peak Loads of 200 MW or Greater, 2007 -2016[2]



Source: Electricity Analysis Office, California Energy Commission.

[1] LADWP, SMUD, Modesto, Anaheim, Riverside, Turlock, Silicon Valley Power, Roseville, Glendale, Pasadena, Burbank, and Redding.

[2] The figure does not include four large or mid-sized entities listed in **Table 1**. IID requested confidentiality for selected values in its filing for 2007 – 2009 and was thus excluded. DWR submitted a five-year resource plan for the State Water Project. Western and NCPA did not submit 10-year resource plans to the Energy Commission. A discussion of DWR, Western, and NCPA resource adequacy plans can be found later in this chapter.

Table 2: Aggregate POU Procurement as a Share of Forecasted Non-Coincident Peak Load (Percent)

Type of Resource	2008	2012	2016
Utility-Owned Resources	92	92	93
Long-Term Conventional Resource Contracts	17	14	9
Long-Term Renewable Resource Contracts	5	5	4
Dispatchable Demand-Side Resources*	2	2	2
Total	116	113	108

Source: Electricity Analysis Office, California Energy Commission.

*Interruptible and emergency load and dispatchable demand response programs

Large Load-Serving Entities — Over 1,000 MW

Los Angeles Department of Water and Power

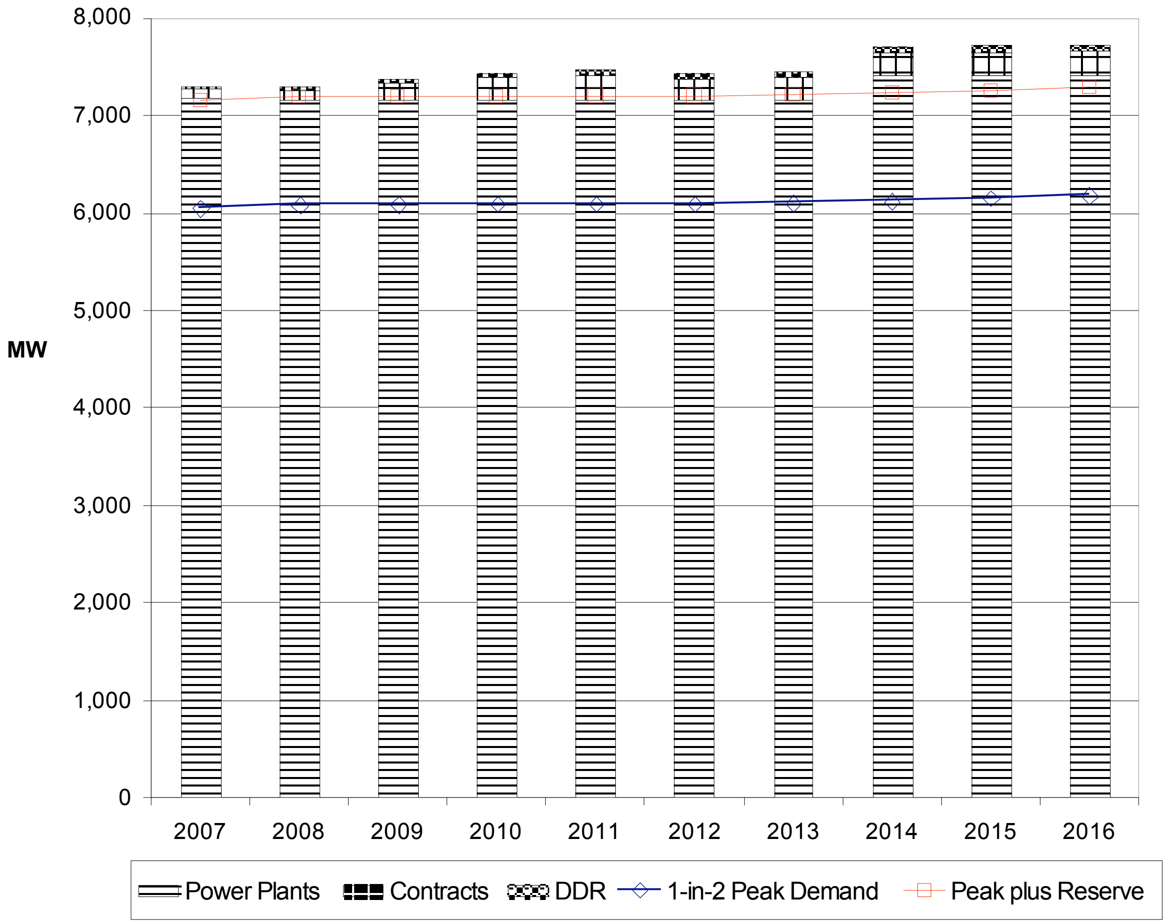
The Los Angeles Department of Water and Power's (LADWP) annual peak load in 2006 was 6,165 MW. Forecasted peak-hour load in 2007 is 6,065 MW in August. LADWP operates a control area that serves the LADWP utility and the cities of Burbank and Glendale.

LADWP determines its reserve margin by using the WECC rule concerning the loss of the so-called "most severe single contingency." For LADWP, the forced outage of Haynes Units 8-10, which operate as a single combined cycle generator, is the most severe single contingency, in most cases. The second most severe single contingency, again in most cases, is the loss of one unit of the Intermountain Power Project. These contingencies define capacity amounts needed for contingency and replacement reserves, so that the total reserve requirement (under peak load conditions) is 1,106 MW.

The complete narrative statement on LADWP's resource adequacy is included in Appendix B-1.

Figure 3 shows that LADWP has sufficient resources to exceed its annual 1-in-2 peak demand peak, plus the 1,106 MW planning reserve margin, over the entire 10-year planning period.

Figure 3: LADWP 10-Year Load/Resource Balance



Source: LADWP filing, February 21, 2007.

LADWP relies primarily upon utility-owned resources to provide power to its customers. These include the Harbor, Haynes, Scattergood, Valley, Palo Verde, Navajo, Intermountain, and Navajo thermal facilities, along with hydroelectricity from the Hoover, Castaic pumped storage, and LA Aqueduct facilities. The 7,160 MW of capacity from utility-owned resources increase to 7,413 MW in 2014 with the planned replacement of Haynes' Units 5 and 6. Long-term renewable resource contracts increase from 2 percent of peak demand in 2008 to 4 percent in 2016. LADWP's *Draft 2006 Power System Integrated Resource Plan* (IRP) assumes that LADWP will add renewable resources to total 20 percent of its energy retail sales by 2010.[19]

Table 3 illustrates the role of both existing resources and the Haynes replacement in meeting the utility's needs over the long run.

[19] LADWP, Power System Integrated Resource Plan; http://www.ladwp.com/ladwp/cms/ladwp005148.jsp

Table 3: LADWP Procurement Shares of Forecasted Peak Load (Percent)

Type of Resource	2008	2012	2016
Utility-Owned Resources	118	117	120
Long-Term Renewable Resource Contracts	2	3	4
Dispatchable Demand-Side Resources (DDR)	<1	<1	1
Total	120	120	125

Source: LADWP filing, February 21, 2007.

Sacramento Municipal Utility District

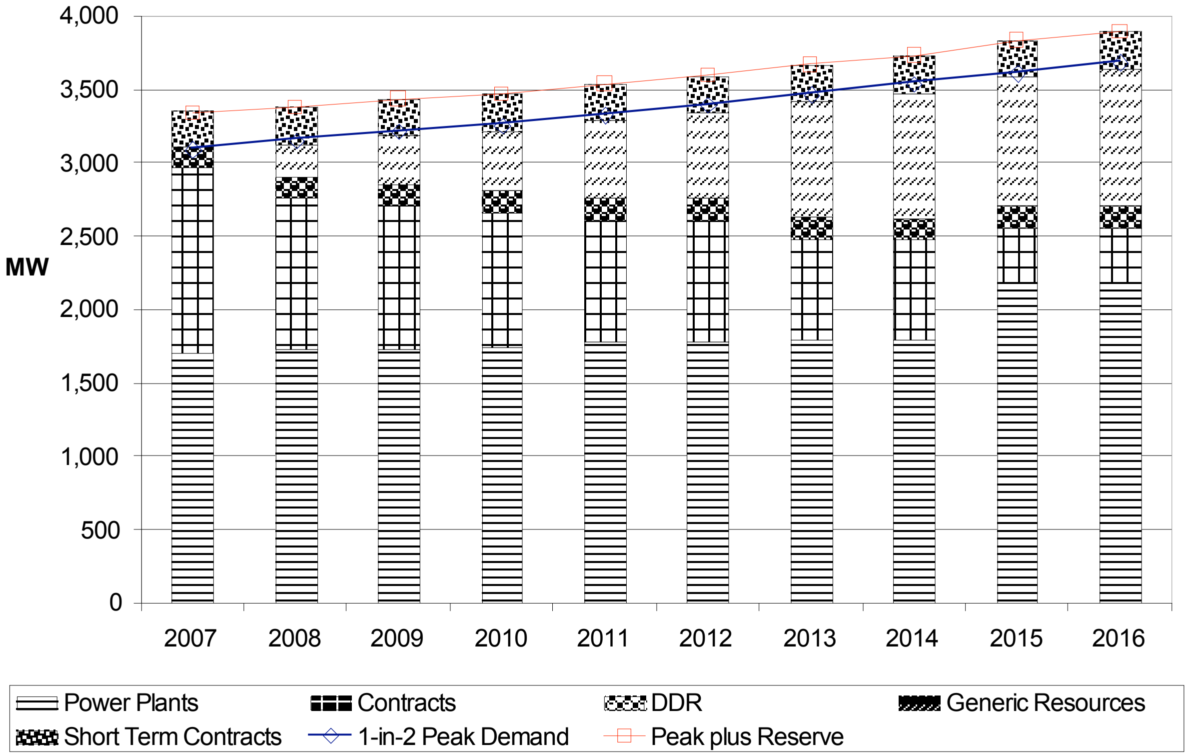
The Sacramento Municipal Utility District's (SMUD) annual peak load in 2006 was 3,280 MW. Forecasted peak-hour load in 2007 is 3,091 MW in July. SMUD is within the SMUD/Western control area; SMUD serves as the control area operator and balancing authority. Five other LSEs are part of the Western sub-control area including Western, Redding, Shasta Lake, Roseville, and Modesto.

The following paragraphs are excerpted from SMUD's narrative on its resource adequacy protocols:

> SMUD has adopted a 15 percent planning reserve margin [above SMUD's forecast 1-in-2 peak load] as a minimum requirement, and employs a procurement plan including timing and targets similar to what the CPUC has set for the IOUs. This plan requires SMUD to procure 90 percent of its projected monthly peak, including a 15 percent planning reserve margin, by October of the prior year; the remaining peak requirement (10 percent) can be procured monthly, provided the summer months (May through September) must be procured no less than 30 days prior to the first of the month.
>
> SMUD formally uses WECC/NERC reliability standards and ensures it can meet these during peak conditions. SMUD plans to have sufficient physical capability to serve adverse condition (1-in-10 year) loads while meeting these reliability standards.

SMUD meets its July 1-in-2 peak demand plus 15 percent planning reserve margin through utility-owned or controlled resources, long- and short-term contracts, and generic resources (planned but not yet specified). SMUD currently has initiatives for loads and resources not reflected in the February 2007 filing. Subsequent to this filing, SMUD's Board of Directors established an energy efficiency reduction target of 15 percent in 10 years. Based on this previously uncommitted energy efficiency program, SMUD's estimated peak reduction demand is 19 MW in 2008, 101 MW in 2012, and 185 MW in 2016. SMUD is developing solar generation goals that would further reduce peak demand by 3 MW in 2008, 9 MW in 2012, and 17 MW in 2016. On the supply side, "Beyond 2011, SMUD fully expects to pursue additional renewables that will allow SMUD to both maintain its RPS goals and to assist in reducing carbon impacts" (SMUD supplemental filing, May 31, 2007, page 4).

Figure 4: SMUD 10-Year Load/Resource Balance



Source: SMUD filing, February 12, 2007.

The decreasing share of both conventional and renewable resources provided by the long-term contracts in SMUD's portfolio will be substantially replaced by new utility-owned hydroelectric and renewable generation. In 2008, utility-owned generation will include Campbell Soup, Carson Ice, Cosumnes, McClellan, Proctor & Gamble, and various hydroelectric facilities. The 2008 capacity total of 1,737 MW increases to 2,187 MW with the assumed addition of the Iowa Hill pumped storage facility (390 MW) and an increase in SMUD-owned renewable generation. Long-term contracts with the California Department of Water Resources SWP, Klamath Falls, PacifiCorp, PPM, UC Med Center, and Western will provide 830 MW of capacity in 2008. SMUD assumes that 369 MW of generic renewable resources will be added to its portfolio by 2016, replacing expiring renewable contracts and contributing to its renewable energy goals.

Table 4 illustrates SMUD's existing resources and the additions of Iowa Hill and utility-owned renewable projects as a share of its forecasted peak loads.

Table 4: SMUD Procurement Shares of Forecasted Peak Load (Percent)

Type of Resource	2008	2012	2016
Utility-Owned Resources*	57	54	64
Long-Term Conventional Resource Contracts	27	20	11
Long-Term Renewable Resource Contracts	6	4	0
Dispatchable Demand-Side Resources (DDR)	5	4	4
Total	95	82	79

Source: SMUD filing, February 12, 2007.

*Does not include generic resources.

Other Governmental Entities — Over 1,000 MW

California Department of Water Resources

DWR provided a 2006 peak load estimate of 2,030 MW for the State Water Project (SWP). This represents the non-coincident peak pumping load for the SWP, which by design occurs during off-peak hours. At the time of the annual peak load for the California ISO control area, SWP's pumping loads were about 1,350 MW. Forecasted peak pumping load for SWP in 2007 is 1,940 MW during off-peak hours in June and in September. Forecasted peak load during on-peak hours in 2007 is 1,234 MW in July.

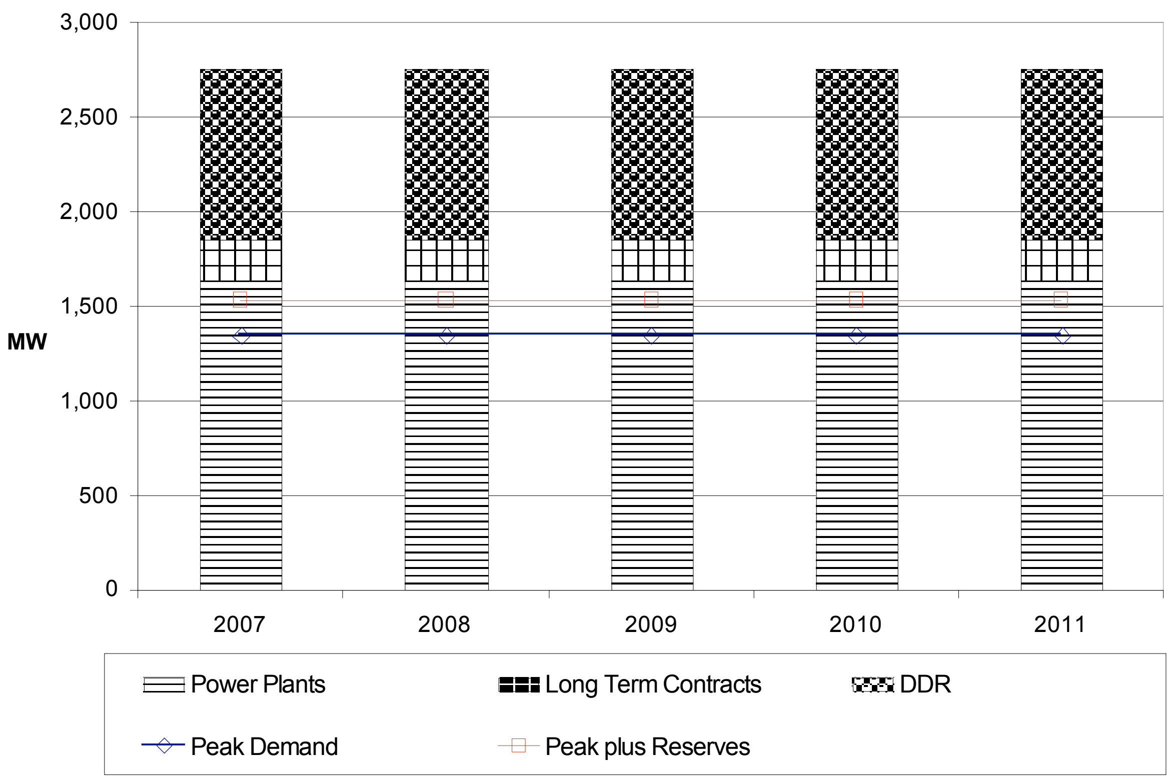
It is noteworthy that not all of SWP's load is firm:

> The SWP differs from most other LSEs in that it is not obligated to serve its entire load at all times. While a portion of this load is firm, the majority of SWP load in any given hour could be deferred, freeing energy for others to use in the immediate period. … Demand response is not exactly a free service for SWP because of the increased wear on the units, but the SWP's customers are not otherwise disadvantaged … assuming the pumping is made up in a reasonable time. (DWR filing, January 31, 2007).

Pumping loads and southward water conveyance have not grown with population. DWR SWP must prepare for year-to-year variations in energy demand that are unlike those experienced by any other LSE. DWR SWP's worst-case scenario in terms of energy demand is the normal water year because that means that water demand exists and water is available. In the alternative cases, either the water year is below normal, reducing available water supply, or the water year is above normal, reducing water demand. Either alternative case therefore reduces the energy demand for pumping.

Figure 5 illustrates both DWR SWP's surplus capacity at the time of the control area coincident annual peak and DWR SWP's ability to shift pumping loads during peak hours. DWR depends upon self-scheduling its hydroelectric resources and bilateral contracts to meet its pumping requirements and its contractual obligations. In addition to these resources, SWP has 898 MW of dispatchable demand response due to flexibility in the timing of pumping demand.

Figure 5: DWR SWP Five-Year Load/Resource Balance



Source: DWR filing, January 31, 2007.

Table 5 represents DWR SWP's existing resources, as shares of its forecasted peak load.

Table 5: DWR SWP Procurement Shares of Forecasted Peak Load (Percent)

Type of Resource	2008	2009	2010	2011
Utility-Owned Resources	121	121	121	121
Long-Term Conventional Resource Contracts	16	16	16	16
Dispatchable Demand-Side Resources (DDR)	67	67	67	67
Total	204	204	204	204

Source: DWR filing, January 31, 2007.

Mid-Sized Load-Serving Entities — 200 MW to 1,000 MW

Imperial Irrigation District

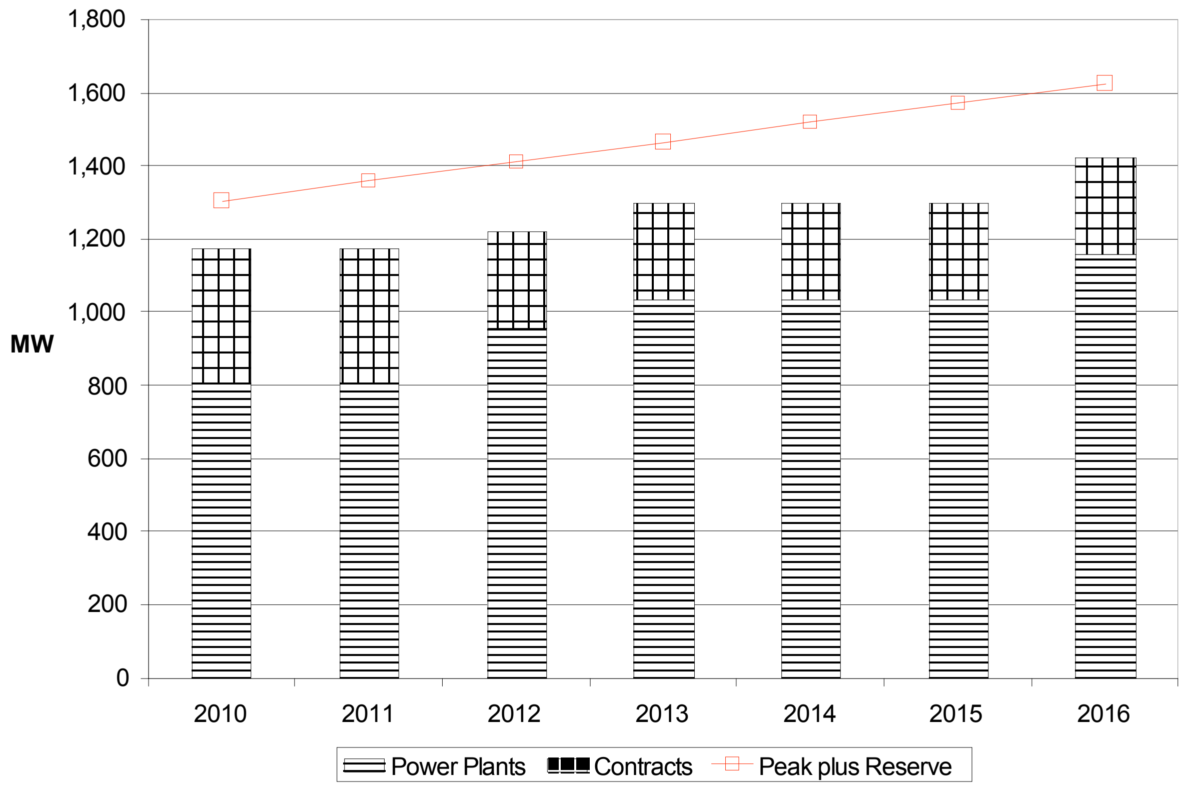
The Imperial Irrigation District's (IID) annual peak load in 2006 was 993 MW. IID operates its own control area.

The IID filing reveals that it does not currently have a board-adopted resource adequacy policy. However, the IID energy staff has developed a resource adequacy plan that has been approved by the IID Risk Oversight Committee. And IID energy staff is drafting resource adequacy protocols for formal IID board approval. IID has been using a 15 percent planning reserve margin for several years. To date IID has never had any supply shortages during real-time operations, even though IID experiences extreme demand variances due to weather-driven load.

The lack of an adopted resource adequacy policy by IID has so far not been identified as a statewide or regional concern, most likely due, in part, to the unique circumstances of IID's electricity geography. IID operates its own control area, and no other LSEs serve loads within that control area. If IID is short on supply during real time operations, IID's customers alone suffer from load shedding; except in specific emergencies, IID cannot rely upon other LSEs or control area operators to provide additional resources for its operational reliability. Failure to meet NERC reliability standards for the control area, therefore, can only be a result of either IID action or inaction; any financial penalties imposed are borne solely by IID and its customers. IID and its board are committed to meeting and exceeding NERC Reliability Criteria. (IID filing September 26, 2007)

Figure 6 shows the need for additional resources by 2010 (and continuing through 2016) to serve forecasted annual peak load plus a 15 percent planning reserve margin. IID estimates demand growth at 42 percent over the planning period, a growth rate that is comparable to that forecasted by Energy Commission staff. The final revised Energy Commission staff forecast for IID's peak load under 1-in-2 conditions in 2010 and 2016 is 1,097 MW and 1,327 MW, respectively. IID relies primarily on utility-owned resources and long-term contracts to provide power.

Figure 6: IID Load/Resource Balance



Source: Imperial Irrigation District filing, February 1, 2007.

IID requested confidentiality for several reported values listed in its 10-year resource plan. This summary, therefore, does not contain information on generic resource additions, spot contracts, or near-term loads and resources through 2009. **Table 6** illustrates the role of utility-owned generation and long-term contracts in meeting the utility's needs over the long run.

Table 6: IID Procurement Shares of Forecasted Peak Load (Percent)

Type of Resource	2010	2013	2016
Utility-Owned Resources	78	78	82
Long-Term Conventional Resource Contracts	28	15	14
Long-Term Renewable Resource Contracts	7	5	5
Total	113	98	101

Source: Imperial Irrigation District filing, February 1, 2007.

Modesto Irrigation District

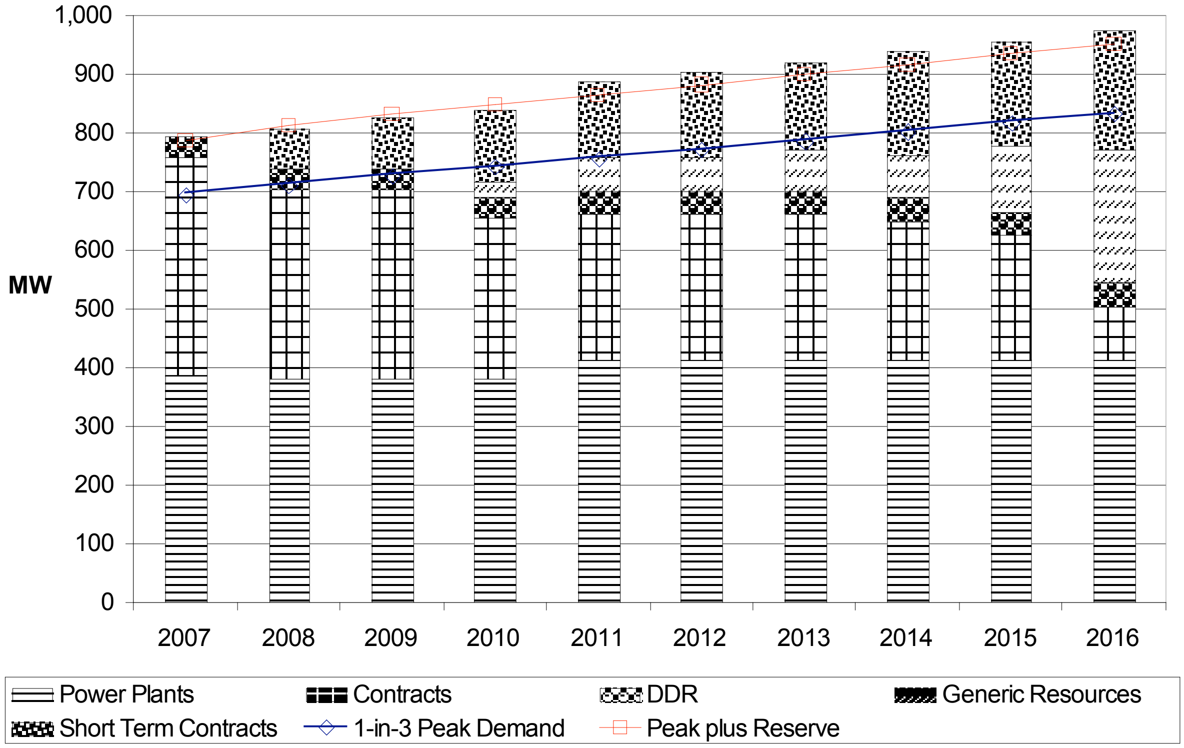
The adjusted annual peak load for the Modesto Irrigation District (MID) in 2006 was 716 MW on July 24. This number includes 29 MW of air conditioner cycling and interruptible load that was curtailed during the peak hour that day and 687 MW of demand that was served during the peak hour that day. The peak load of actual metered deliveries occurred on July 25 and was 697 MW, which does not include 7.4 MW of interruptible load that was called on during that hour. Actual metered deliveries is the value most commonly reported, and is the number listed in Appendix Tables A-1 and A-2. However, the adjusted peak load is used by MID in load forecasting to positively incorporate the benefits of demand side management programs. Forecasted peak-hour load in 2007 is 695 MW in August. MID is located in the SMUD/Western control area, and is part of the Western sub-control area.

MID staff is presently developing a formal resource adequacy policy to submit to its Board for approval. Historically, the utility has used a minimum planning reserve margin equal to 115 percent of its monthly peak-hour demand. By February 2007, MID had capacity equal to at least 116 percent of its peak demand for all months in 2007. MID develops an annual demand and energy forecast and prepares a resource plan twice a year. Unique to MID, its peak demand forecast is based upon a 1-in-3 year peak temperature of 106 degrees or higher.

MID has two basic operations for the procurement of ancillary services. Operating as a member of the Western sub-control area within SMUD's control area, MID is obligated to either self-provide or purchase spinning and non-spinning reserves for its share of the Western sub-control area. MID also pays a monthly regulation fee to Western for the right to operate within a 9 MW regulating band.

Figure 7 illustrates that, in the short term, MID relies on a mix of utility-owned resources, long-term contracts with conventional resources, and demand-side programs to meet its capacity needs. Over the long term, a substantial amount of capacity from other sources will be needed.

Figure 7: MID 10-Year Load/Resource Balance



Source: Modesto Irrigation District filing, February 1, 2007.

Physical assets in Modesto's portfolio include McClure, Ripon, Woodland, and hydroelectric facilities. The current 387 MW of capacity from these resources increase to 414 MW with the expected 2011 completion of a 32 MW reciprocating plant. Long-term conventional resource contracts with Barclays, Calpine, Morgan Stanley, PPM, and UBS provide 235 MW of capacity in 2008. These decrease to 68 MW in 2016. Long-term renewable contracts fall from 9 percent of peak demand in 2008 to 3 percent in 2016. MID does have a board-approved Renewables Portfolio Standard with a target of 20 percent of annual retail energy sales in 2017. MID increases its reliance on short-term contracts and generic resources (planned but not yet specified resources) in its portfolio throughout the planning period.

Table 7 illustrates the role of both existing resources and the above-mentioned addition in meeting the utility's needs over the long run.

Table 7: MID Procurement Shares of Forecasted Peak Load (Percent)

Type of Resource	2008	2012	2016
Utility-Owned Resources*	54	52	50
Long-Term Conventional Resource Contracts	37	23	8
Long-Term Renewable Resource Contracts	9	8	3
Dispatchable Demand-Side Resources (DDR)	2	2	2
Total	102	85	63

Source: Modesto Irrigation District filing, February 1, 2007.

*Does not include generic resources.

City of Anaheim

Annual peak load in 2006 was 593 MW. Forecast peak-hour load in 2007 is 562 MW in August. Anaheim is located in the California ISO control area and is in the LA Basin load pocket.

The Anaheim City Council adopted a resource adequacy program in April 2006. (Appendix B)

Anaheim prepares an annual resource adequacy plan that identifies resources "sufficient to initially meet the greater of 112 percent of Anaheim's forecast monthly peak loads for October through April, and 100.8 percent of Anaheim's forecast monthly peak loads for May through September."

Anaheim plans to achieve a higher planning reserve margin after it installs peaking generation within its service area. "The objective of the plan will be to achieve no less than a 12 percent reserve margin over monthly peak loads transitioning to a minimum 15 percent reserve margin by 2010." The staff recommendation of April 25, 2006, outlined a plan to attain and maintain this higher standard of resource adequacy:

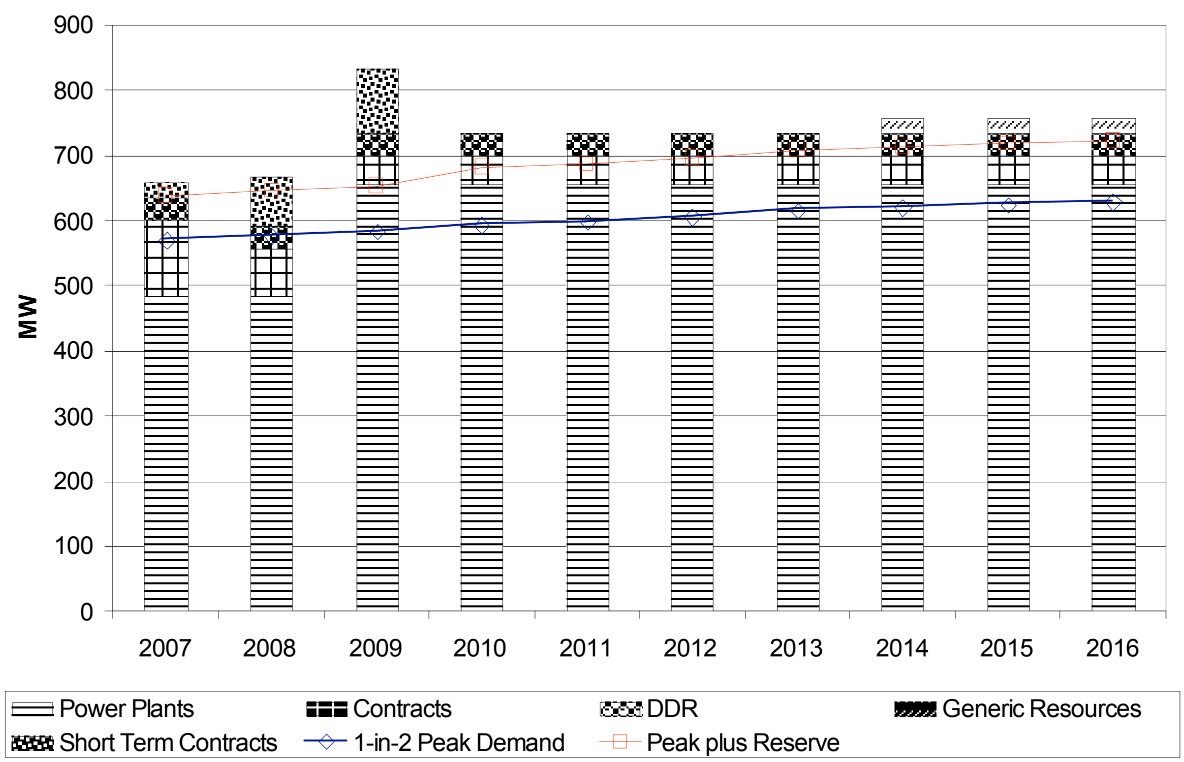
> The longer-term generation plan that the Department plans to bring to the City Council will include the recommendation to install 170 MW - 200 MW of peaking generation inside Anaheim before the end of this decade, which will be enough capacity, appropriately located within Anaheim, to meet future demand and reserve needs for several years. Until that time the Department will utilize short-term contracts to cover the summer requirements, particularly in 2008 when Anaheim's interest in the San Onofre Nuclear Generating Station (SONGS) is

expected to be no longer a part of Anaheim's portfolio as a result of the settlement agreement with SCE.

Like the majority of LSEs that define this term, Anaheim states that a qualifying capacity of thermal generating facilities "will be based on net dependable capacity [as] defined by … GADS" (NERC's Generating Availability Data System). As a metered subsystem, Anaheim will make available to the California ISO all capacity that is not required to serve Anaheim's loads during a system emergency.

Figure 8 shows that resources in Anaheim's procurement plan exceed the August 1-in-2 demand peak plus their adopted planning reserve margin over the entire planning period. Anaheim increases its planning reserve margin from 12 percent in 2008 to 15 percent in 2010.

Figure 8: Anaheim 10-Year Load/Resource Balance



Source: City of Anaheim filing, February 1, 2007.

Anaheim primarily relies on utility-owned generation for its capacity needs. These include the Magnolia, Anaheim, San Juan, and Intermountain thermal facilities. The current 450 MW of capacity from owned resources increases to 622 MW with the expected summer 2009 completion of three new Anaheim-owned plants.

Contracts with Western, IPP, DWR, and Coral provide 50 MW of capacity in 2008. Long-term renewable contracts increase from 4 percent of peak demand in 2008 to 7 percent in 2016. Anaheim includes short-term contracts in its portfolio until the completion of these new plants (and as a precaution should the availability of these resources be delayed). **Table 8** illustrates the role of existing resources and the proposed additions in meeting the utility's needs over the long run.

Table 8: Anaheim Procurement Shares of Forecasted Peak Load (Percent)

Type of Resource	2008	2012	2016
Utility-Owned Resources	84	106	104
Long-Term Conventional Resource Contracts	9	0	0
Long-Term Renewable Resource Contracts	4	7	7
Dispatchable Demand-Side Resources (DDR)	6	6	6
Total	103	119	117

Source: City of Anaheim filing, February 1, 2007

City of Riverside

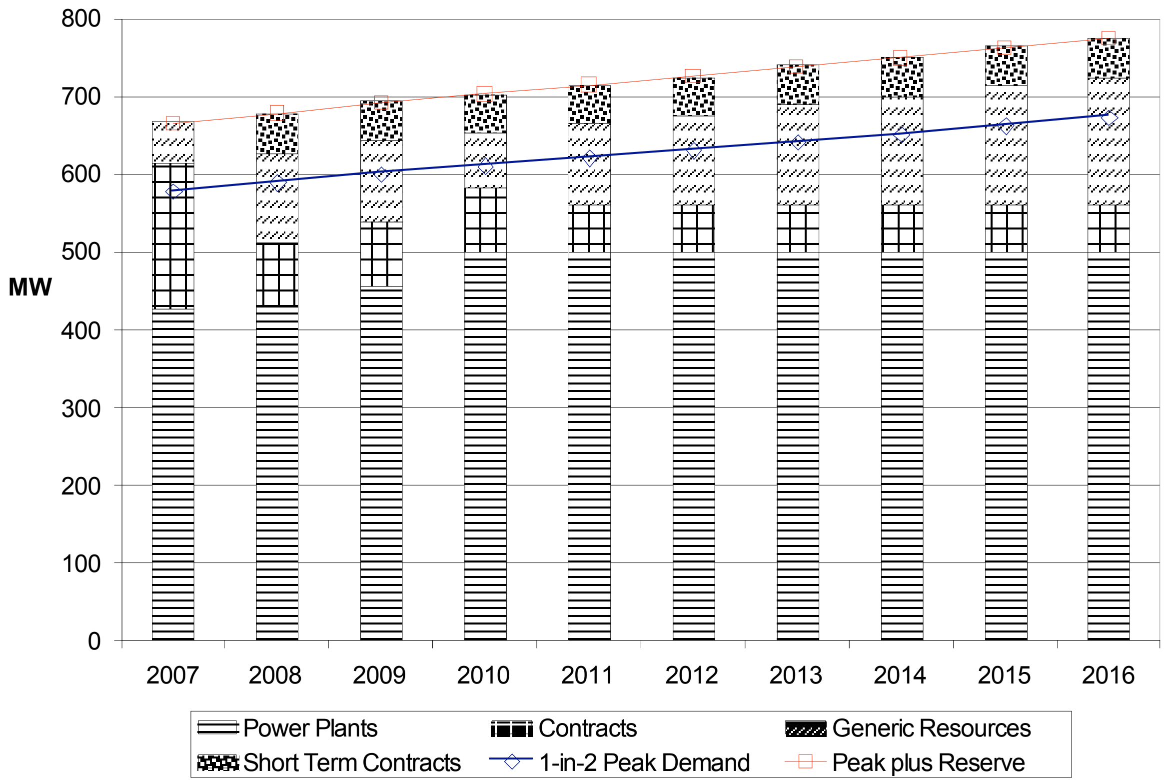
The city of Riverside's annual peak load in 2006 was 587 MW. Forecast peak-hour load in 2007 is 579 MW in August. Riverside is located in the California ISO control area and is in the LA Basin load pocket.

The City of Riverside Public Utilities Department adopted a resource adequacy program in May 2006. This program established capacity counting conventions for resources that are dynamically scheduled, energy limited, or renewable. Riverside has adopted a 15 percent planning reserve margin measured at Vista substation, the take-out point from the California ISO. The value at Vista includes distribution losses. An additional 3 percent is added to the forecasted value to estimate transmission losses to Vista. Riverside's monthly peak forecast is based on 1-in-2 year weather.

Riverside has a transmission plan, summarized on its website, which would add both new substations and new internal transmission lines. Riverside has only one substation for imported power and needs another for the long term, an investment that has been considered and planned for decades.

Figure 9 shows that Riverside will require additional resources to meet its capacity needs during the coming decade. It primarily relies upon the direct ownership of power plants to provide the majority of its capacity needs.

Figure 9: Riverside 10-Year Load/Resource Balance



Source: City of Riverside filing, January 24, 2007.

Physical assets in Riverside's portfolio include the Riverside Energy Resource Center (RERC), Deseret, Springs, Palo Verde, San Onofre, Intermountain, and five renewable facilities. Capacity from utility-owned resources totals 430 MW in 2008 and is expected to increase to 501 MW with the 2010 expansion of RERC and increased capacity from renewable facilities with the termination of the Deseret PSA. Contracts with BPA and DWR provide 83 MW of capacity from 2008 through 2010 and 60 MW through 2016. Riverside includes 50 MW of short-term contracts in its portfolio from 2008 through 2016.

Table 9 illustrates Riverside's existing resources, including the RERC expansion, as a share of forecasted peak loads.

Table 9: Riverside Procurement Shares of Forecasted Peak Load (Percent)

Type of Resource	2008	2012	2016
Utility-Owned Resources	73	77	74
Long-Term Conventional Resource Contracts	14	9	9
Total	87	86	83

Source: City of Riverside filing, January 24, 2007.

Turlock Irrigation District

Turlock Irrigation District's (TID) annual peak load in 2006 was 533 MW. Forecasted peak-hour load in 2007 is 504 MW in July and August.

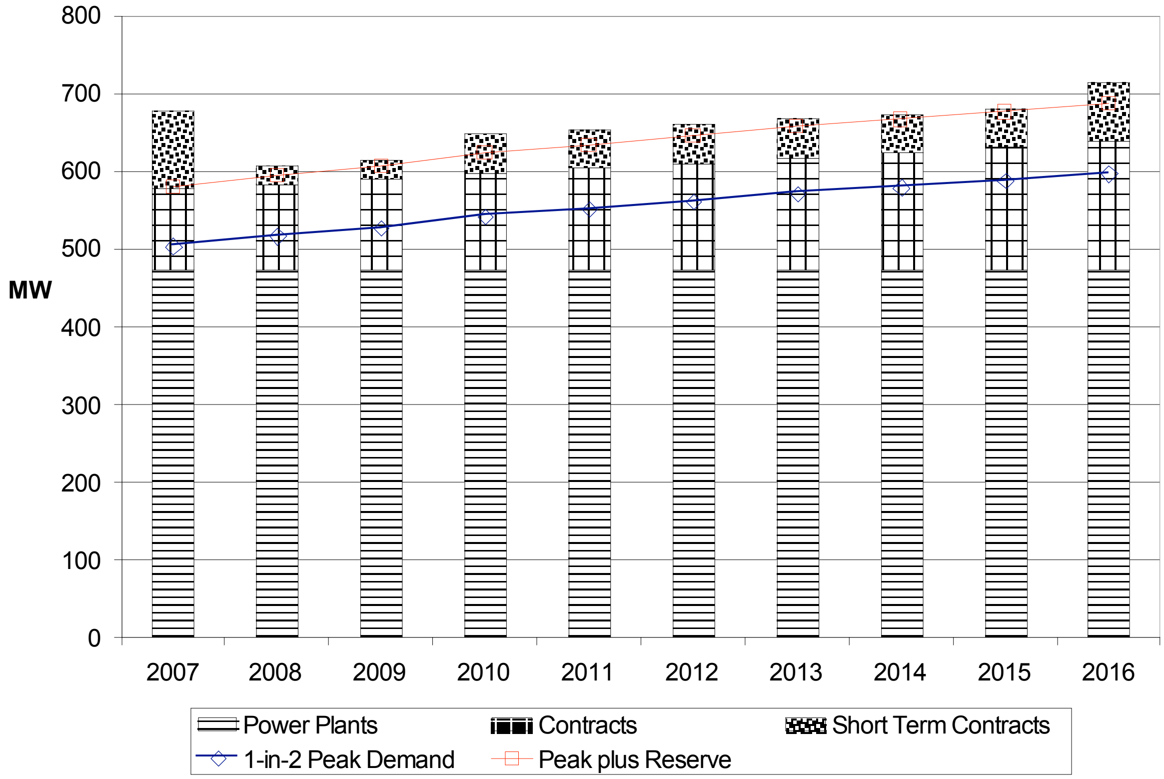
TID operates the newest control area in California for the benefit of both TID and the Merced Irrigation District. TID presently provides nearly all the capacity and energy that Merced needs for its loads, along with ancillary services. A modest supply for Merced from Western is also delivered through TID.

TID produces a demand forecast for the summer months (May through September) by June 1 of the preceding year and acquires the capacity needed to meet 105 percent of those monthly peaks at that time. This month-ahead procurement standard for TID is the same as that imposed by the California ISO tariff: 115 percent by April 30, for example, for the median forecast of peak load in June.

TID's capacity counting conventions for its hydro plants are defined as follows. The utility bases estimates of capacity from its New Don Pedro facility on current reservoir levels and snowpack, and on a 1-in-5 dry year forecast for precipitation. For their run-of-canal power plants, capacity is based on actual or forecasted flows and canal head.

Figure 10 shows that resources in TID's procurement plan exceed August 1-in-2 peak demand plus planning reserve margin over the entire planning period. TID also has a firm sales obligation to Merced ID for 82 MW under two contracts that expire before summer 2008.

Figure 10: TID 10-Year Load/Resource Balance



Source: Turlock Irrigation District filing, February 7, 2007.

TID primarily relies on utility-owned or controlled resources to provide power. These include the Walnut and Almond gas-fired power plants and hydroelectric facilities. The 475 MW of capacity from owned resources is constant over the planning period. Contracts with Boardman, Western, and CCSF provide approximately 80 MW of capacity through 2016. Long-term renewable contracts increase from 4 percent of peak demand (29 MW) in 2008 to 7 percent (87 MW) in 2016. TID includes short-term contracts in its portfolio. **Table 10** shows TID's existing resources as a share of forecasted peak load.

Northern California Power Agency—Power Pool

Annual peak load in 2006 for the Northern California Power Agency (NCPA) power pool was 527 MW. Forecasted peak-hour load in 2007 for the power pool is 480 MW.

Table 10: TID Procurement Shares of Forecasted Peak Load (Percent)

Type of Resource	2008	2012	2016
Utility-Owned Resources	92	82	79
Long-Term Conventional Resource Contracts	16	14	13
Long-Term Renewable Resource Contracts	6	10	15
Total	114	106	107

Source: Turlock Irrigation District filing, February 7, 2007.

NCPA provided resource adequacy policy statements for all 10 members of the NCPA power pool. These policy statements were adopted in 2006 by either the governing board or the city council of each LSE.

NCPA itself is not a load-serving entity with the statutory or regulatory obligation to serve end-use customer load. However, NCPA is authorized to act on behalf of its members who are publicly owned LSEs. In this role, NCPA serves as scheduling coordinator for all 10 members of the NCPA power pool, all of which serve load in the California ISO control area. The 10 LSE members of the NCPA power pool are Plumas Sierra Rural Electric Cooperative and nine small POUs: Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Port of Oakland, and Ukiah.

The POU members of the NCPA power pool have a Metered Subsystem-Aggregator (MSS-A) Agreement with the California ISO. Plumas Sierra has its own Metered Subsystem (MSS) Agreement with the California ISO. The NCPA power pool, including all 10 members, is managed as an aggregate load served by pooled resources. The procurement target is generally 120 percent to 130 percent. This includes 125 MW of pure peakers – combustion turbines (CTs) located in Alameda, Lodi, and Roseville. These CTs have no practical value for generating monthly energy to serve loads. The CTs are almost exclusively used in emergencies, contingencies, or for resource adequacy capacity demonstrations. The CTs in Alameda are still covered by reliability-must-run contracts (RMR). The CTs in Lodi are limited by emissions restraints. NCPA has reserved emission allowances from the Lodi CTs for use during summer hours.

NCPA uses the "pmax" values for qualified capacity, as certified by the California ISO. For geothermal resources, this incorporates some capacity derates. NCPA self provides ancillary services and regularly provides them to the market. Collierville hydro on the Stanislaus River is the workhorse in this respect and has installed automated governor controls.

The NCPA resource portfolio is primarily load following, which is recognized in the terms of the MSS-A Agreement. NCPA has strong financial incentives to match supplies with power pool loads within 3 percent, at all times. Under supply by more than 3 percent results in 200 percent penalties, plus the energy purchase cost (essentially 300 percent). An oversupply of more than 3 percent means the energy is essentially provided to the California ISO for free. The load/resource balances are calculated incrementally in real time every 10 minutes.

NCPA is currently helping Ukiah bring Lake Mendocino back on-line. This 3 MW hydro plant will be dispatched based on water release requirements. Ukiah, as the plant owner, will count the renewable energy generated by this plant. NCPA has two firmed wind energy contracts from the High Winds and Shiloh projects. Power pool members are extremely interested in adding more wind resources to their portfolios.

Instead of a standard year-ahead IRRP filing, NCPA provides an “NCPA IRRP Capacity Reserve Verification” each year to the California ISO. On behalf of pool members, NCPA is formally required to secure enough capacity to meet the coincident peak demand of the power pool plus 15 percent for capacity reserves. Since all NCPA power pool members are in a metered subsystem, by agreement, available capacity resources must be available to the California ISO during an emergency.

The non-coincident peak loads in 2006 for all 10 members of the NCPA power pool are listed in the footnotes to **Table 1** and **Table A-1**. The sum of these 10 non-coincident annual peak loads was 542 MW. The actual coincident peak load for the power pool in 2006 was 527 MW, 2.8 percent lower. This is because the annual peaks for Alameda, Lompoc, and Plumas-Sierra occurred in December.

Silicon Valley Power

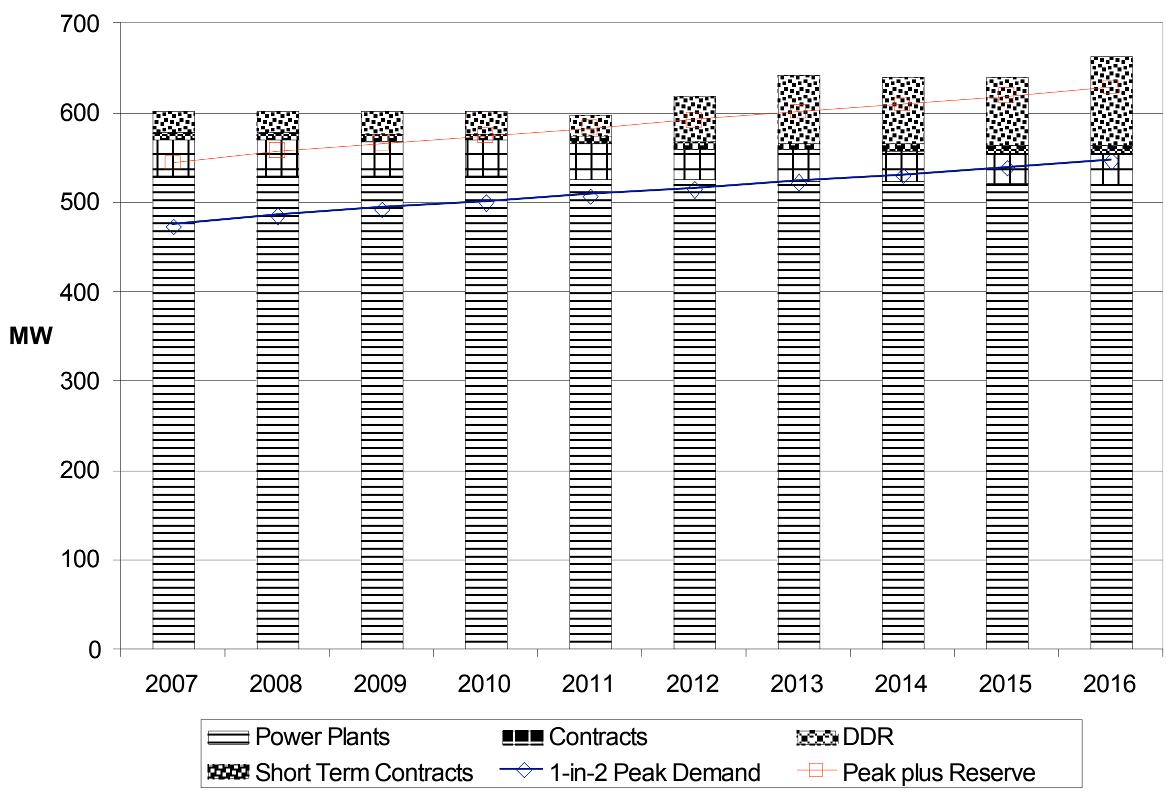
Silicon Valley Power’s (SVP) annual peak load in 2006 was 486 MW. Forecasted peak-hour load in 2007 is 474 MW in August. SVP is located in the California ISO control area and is in the Greater Bay Area load pocket.

NCPA is the scheduling coordinator for SVP. SVP has had a separate MSS agreement with the California ISO since July 2002. By virtue of this agreement, the utility’s generating resources are not subject to the California ISO’s must-offer requirements, though the MSS requires SVP to maintain a capacity reserve. By adopted policy, SVP uses a 15 percent planning reserve margin based on their non-coincident peak demand forecast.

SVP is a member of NCPA, but no longer belongs to the NCPA power pool. The city council for the city of Santa Clara adopted a 12-page Integrated Energy Resource Policy for SVP in April 2006. This document addresses resource adequacy goals, counting conventions, procurement loading preferences, organizational reporting, and risk management, and commits the utility to standards adopted by NERC and the WECC, and to “meet or exceed the standard of care in the industry.”

Figure 11 shows that SVP has existing resources that exceed its August 1-in-2 peak demand plus a 15 percent planning reserve margin through 2010. SVP primarily relies on utility-owned resources to meet its capacity needs.

Figure 11: SVP 10-Year Load/Resource Balance



Source: Silicon Valley Power filing, January 31, 2007.

These include the SVP Cogeneration, SVP Gianera, NCPA, MSR San Juan, geothermal, and hydroelectric facilities. The 531 MW of capacity from utility-owned resources in 2008 decreases to 520 MW in 2016 with the planned derating of geothermal resources. Long-term renewable resource contracts provide 35 MW of capacity; given demand growth their share of peak demand falls from 8 percent in 2008 to 6 percent in 2016. SVP includes short-term contracts in its portfolio. **Table 11** shows SVP’s existing resources as a share of forecasted peak loads.

Table 11: SVP Procurement Shares of Forecasted Peak Load (Percent)

Type of Resource	2008	2012	2016
Utility-Owned Resources	110	102	95
Long-Term Renewable Resource Contracts	8	7	6
Dispatchable Demand-Side Resources (DDR)	<1	<1	<1
Total	118	109	101

Source: Silicon Valley Power filing, January 31, 2007.

Western Area Power Administration

The Western Area Power Administration's (Western) annual peak load for its end-use customers in 2006 was about 500 MW. This includes about 393 MW of end-use load in the California ISO control area and approximately 107 MW of end-load in the SMUD/Western control area. These numbers were estimated by Energy Commission staff and do not include Western's "full requirements" load obligations for LSE customers such as Trinity Public Utility District (PUD) and Lassen Municipal Utilities District (MUD) (described below). End-users in the SMUD/Western control area include loads that are directly connected to Western's transmission, such as Lawrence Livermore Laboratory and a Delta water pumping site.

Western has a role in balancing loads and resources for both itself and the other four LSEs that are part of the Western sub-control area: Redding, Shasta Lake, Roseville, and Modesto.

Western is the local regulatory authority (LRA) for the loads it serves within the California ISO control area. Western does not define itself as an electric retailer. Instead, Western schedules for specific "customers" for which it has different levels of obligation, starting first with Project Use, then First Preference, (for example, Trinity PUD), then Base Resource customers (for example, BART, UC campuses). After those tiers, Western serves 19 Full Load Service customers (for example, Lassen MUD and Pittsburg). Farther still down the load-serving order are the DOE laboratories at Berkeley and Stanford; these loads are sometimes met partly with third-party contracts.

In an "IRRP Resource Adequacy LRA Plan" filed with the California ISO on September 29, 2006, Western committed to "make a year-ahead showing that it has a minimum of 90 percent of the capacity required to meet its forecasted monthly coincident peak load in the California ISO Control Area, as determined by Western, plus its planning reserve margin." That minimum planning reserve capacity will be 10 percent for the months of June through September and 5 percent for the months of October through May. “For its month-ahead showing, Western will demonstrate that it is prepared to meet 100 percent of its forecasted monthly coincident peak load.”

Western’s LRA plan defines how its hydroelectric capacity will be counted for its year-ahead voluntary filing with the California ISO. “Western designates its hydro facilities in the SMUD control area as a system resource, with 100 percent of its forecast capacity as qualifying capacity ... [using] Western’s 50 percent rolling 12 months forecast for the appropriate month.” These 12-month-ahead power operations forecasts of monthly capacity and energy from Central Valley Project facilities are prepared by the U.S. Bureau of Reclamation and posted on-line.[20]

For generation from New Melones on the Stanislaus River in Central California, “Western and the California ISO have agreed to pseudo-tie the generation from New Melones into the SMUD Control Area” electronically and operationally, so that it can be scheduled as firm energy, an imported system resource backed by reserves in the originating control area.

Roseville Electric

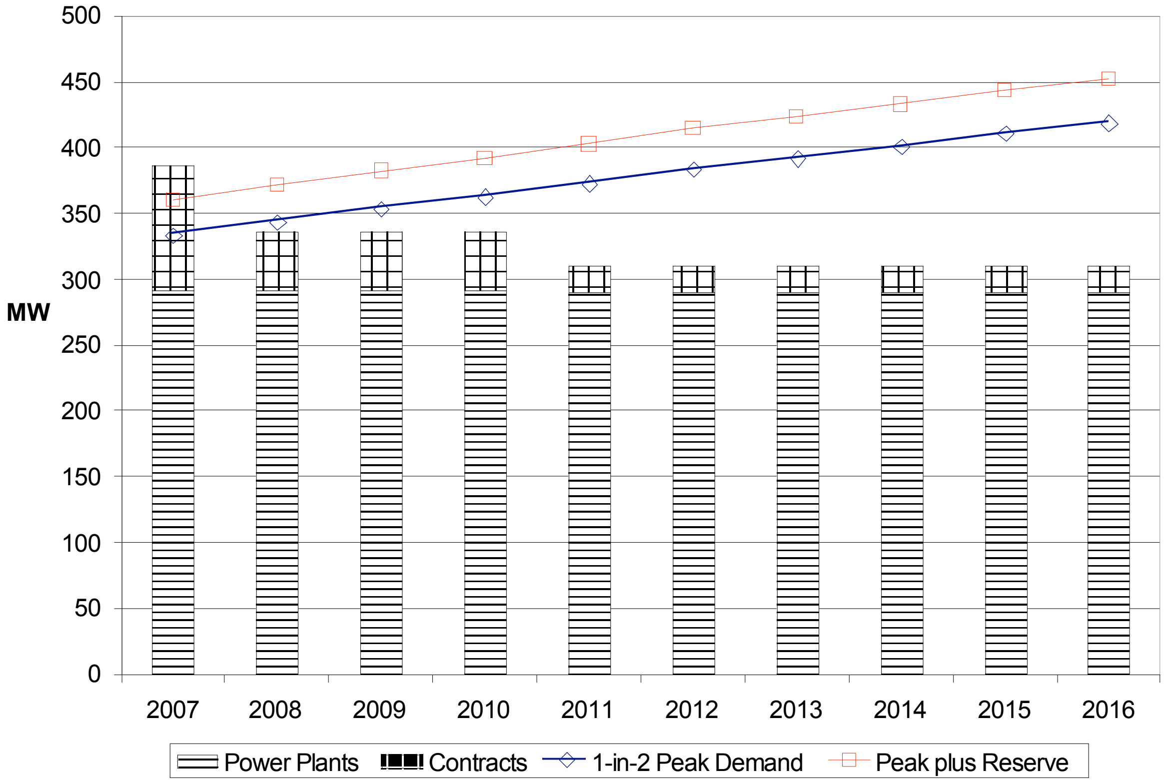
Annual peak load in 2006 was 352 MW. Forecasted peak-hour load in 2007 is 334 MW in August. Roseville is located in the SMUD/Western control area and is part of the Western sub-control area.

The city of Roseville has not yet adopted a formal resource adequacy policy. Roseville provided a 10-year resource plan that included the new 162-plus MW Roseville Energy Park as a dependable long-term supply resource. Since February, Roseville has procured short-term purchases to cover contingencies that may be needed should this new power plant come on-line commercially at a later date than anticipated. This short-term procurement strategy is common when a utility brings a new resource into service, especially when the new capacity represents a substantial share of an LSE’s load.

Figure 12 shows that Roseville primarily relies on utility-owned resources to provide power. These include the Roseville Energy Park, NCPA, and large hydroelectric and geothermal facilities. The 292 MW of capacity available from these resources in 2008 decreases only slightly with the derating of geothermal facilities over the planning period. Contracts with Morgan Stanley (25 MW) and Seattle City and Light (20 MW) provide 45 MW of capacity in 2008. This falls to 25 MW with the expiration of the Morgan Stanley contract after 2010. **Table 12** represents Roseville’s existing resources as a share of its forecasted peak loads.

[20] http://www.usbr.gov/mp/cvo/

Figure 12: Roseville 10-Year Load/Resource Balance



Source: Roseville Electric filing, February 9, 2007.

Table 12: Roseville Procurement Shares of Forecasted Peak Load (Percent)

Type of Resource	2008	2012	2016
Utility-Owned Resources	85	72	69
Long-Term Conventional Resource Contracts	13	5	5
Total	98	77	74

Source: Roseville Electric filing, February 9, 2007.

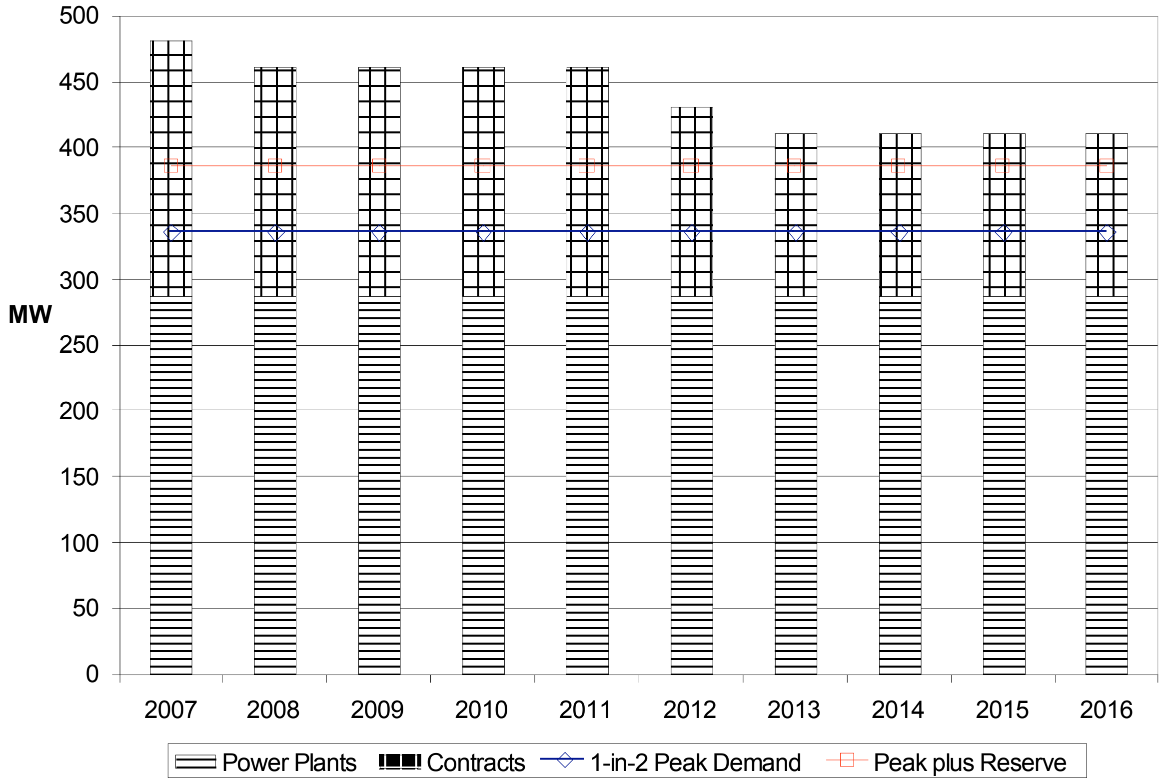
Glendale Water & Power

Glendale Water & Power's annual peak load in 2006 was 336 MW. Forecast peak-hour load for 2007 is 336 MW in July. Glendale is located in the LADWP control area, along with Burbank and LADWP.

Like LADWP and Burbank, Glendale has a planning reserve requirement based on its largest contingency: the loss of Grayson Power Plant's Unit 8 B/C, equal to 74 MW. Thus, Glendale maintains electric resources equal to its forecasted peak load, plus 74 MW. Based on median demand forecasts, this translates to a planning reserve margin of about 23 percent.

Resources in Glendale's procurement plan exceed the July 1-in-2 demand peak plus reserve margin over the entire planning period, as shown in **Figure 13**. Glendale relies on a mix of utility-owned or controlled resources and long-term conventional resource contracts to provide power.

Figure 13: Glendale 10-Year Load/Resource Balance



Source: Glendale Water & Power filing, February 13, 2007.

Utility-owned resources include the 250 MW Grayson gas-fired plant in Glendale. The utility also has a 10 MW share of Palo Verde and a 20 MW share of Hoover. The 280 MW of capacity from these three resources remains constant over the planning period. Glendale also has 160 MW in 2008 from long-term conventional resource contracts with Bonneville, IPA, Magnolia, Portland General Electric, and San Juan. This decreases to 110 MW over the planning period with the termination of the Bonneville and Portland General Electric contracts. The 14 MW of capacity from long-term renewable contracts, consisting of two wind agreements and a geothermal project, remain constant over the planning period. Glendale also has a utility ownership interest of 8 MW in a local landfill.

Table 13 indicates that Glendale's existing resources exceed its forecasted peak load and planning reserve obligations for the next decade.

Table 13: Glendale Procurement Shares of Forecasted Peak Load (Percent)

Type of Resource	2008	2012	2016
Utility-Owned Resources	91	91	91
Long-Term Conventional Resource Contracts	51	41	35
Long-Term Renewable Resource Contracts	4	4	4
Total	147	137	131

Source: Glendale Water & Power filing, February 13, 2007.

Pasadena Water & Power

Pasadena Water & Power's annual peak load in 2006 was 316 MW. Forecast peak-hour load in 2007 is 316 MW in July. Pasadena is in the California ISO control area and is in the LA Basin load pocket.

Pasadena has historically maintained a 15 percent planning reserve margin. It generally makes all on-site generating resources in excess of load available to the California ISO for ancillary services. By purchasing its operating reserve needs from the California ISO, Pasadena meets its operating reserve requirements apart from its resource adequacy obligations.

The majority of Pasadena's long-term energy resource portfolio consists of unit-contingent imports.

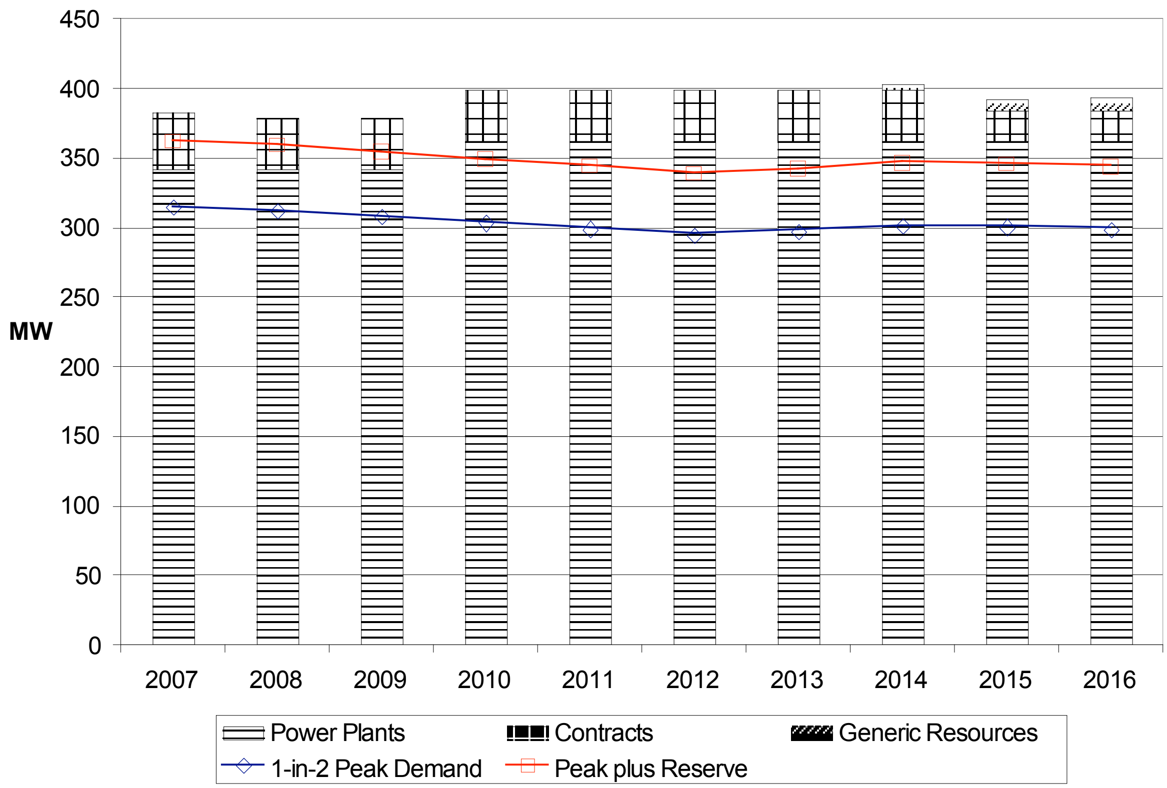
Due to the nature of Pasadena's distribution system, Pasadena has a long-standing policy of maintaining at least 150 MW to 200 MW of generating capacity within its service territory. Pasadena currently has 197 MW of on-site generation, which represents 64 percent of its forecasted peak load for 2007. Pasadena's filing describes Pasadena's intention to repower its oldest and least efficient generating units (110 MW of the 197 MW) by 2010.

For its own draft integrated resource plan, Pasadena prepared an 18-month energy forecast starting with January 2007. Intermountain Power Project (IPP) presently provides about 60 percent of Pasadena's energy supply.

Figure 14 shows that the resources in Pasadena's current portfolio exceed the July 1-in-2 peak demand plus a 15 percent planning reserve margin over the entire forecast period. Peak demand falls over the planning period with uncommitted energy efficiency and uncommitted price-sensitive demand-response programs. Pasadena increases its resulting planning reserve margin from 21 percent in 2008 to 29 percent in 2016.

Table 14 displays the capacity associated with existing SVP resources as a share of its forecasted peak load in subsequent years.

Figure 14: Pasadena 10-Year Load/Resource Balance



Source: Pasadena Water & Power filing, February 15, 2007.

Pasadena primarily relies on utility-owned resources to provide power. These include the Broadway, Glenarm, Magnolia, Palo Verde, and Intermountain facilities; Pasadena has 343 MW of capacity from these resources in 2008. Pasadena proposes to add a locally sited 130 MW facility by 2010, replacing the Broadway facility and two units at the Glenarm facility, resulting in a net increase of 20 MW. Summer-month peaking contracts with BPA provide 15 MW of capacity through 2014. Long-term renewable contracts remain constant over the planning period. **Table 14** shows Pasadena's existing resources, including the planned net addition, as shares of forecasted peak load.

Table 14: Pasadena Procurement Shares of Forecasted Peak Load (Percent)

Type of Resource	2008	2012	2016
Utility-Owned Resources	110	121	122
Long-Term Conventional Resource Contracts	5	5	0
Long-Term Renewable Resource Contracts	7	7	7
Total	122	133	129

Source: Pasadena Water & Power filing, February 15, 2007.

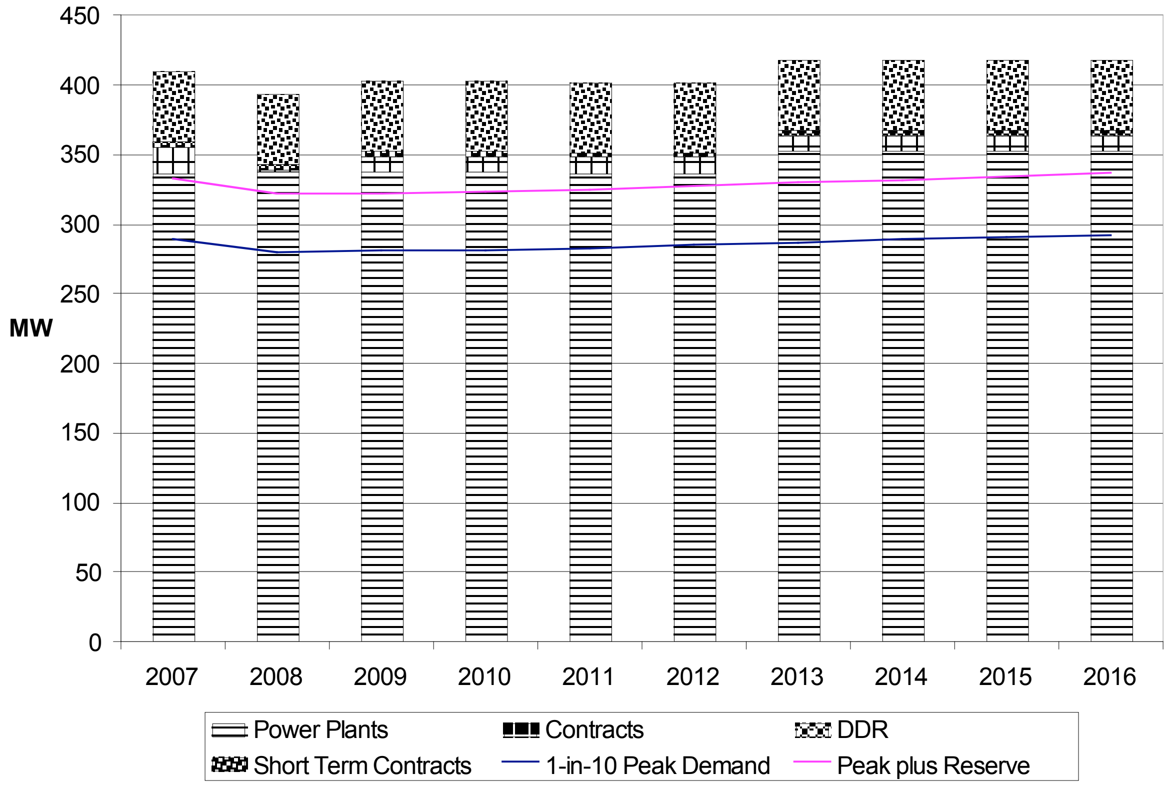
Burbank Water & Power

Burbank Water & Power's annual peak load in 2006 was 307 MW. Forecast peak-hour load in 2007 is 294 MW in July. Burbank is located in the LADWP control area.

For resource planning, Burbank uses the performance criterion to meet all loads in a year 90 percent of the time. That translates to a 1-in-10 chance that loads in any given year will exceed available resources (plus reserves that are at least equal to Burbank's greatest risk). Burbank uses the minimum planning reserve and reliability criteria recommended by the Board of Trustees of the Western Systems Coordinating Council (WSCC), the institutional predecessor of the WECC. These WSCC standards, which differ significantly from a "rule-of-thumb" 15 percent planning reserve margin, are now used by Burbank, Glendale, and LADWP.

Figure 15 shows that Burbank relies primarily on utility-owned resources to meet its capacity needs; total capacity from these resources exceeds 117 percent of its peak loads over the entire planning period. These resources include 231 MW from the Magnolia, Lake, and Olive gas-fired plants in Burbank, a 10 MW share in Palo Verde, and a 75 MW share in Intermountain. The capacity from these resources remains constant at 316 MW over the planning period. These resources are augmented in 2013 with the addition of a planned geothermal unit. Long-term renewable contracts are planned to increase to 4 percent of peak demand in 2016. Burbank includes short-term contracts in its portfolio. The resulting planning reserve margin is greater than 40 percent. **Table 15** expresses the capacity associated with Burbank's existing resources, plus the planned geothermal addition, as a share of forecasted peak demand in selected future years.

Figure 15: Burbank 10-Year Load/Resource Balance



Source: Burbank Water & Power filing, February 13, 2007.

Table 15: Burbank Procurement Shares of Forecasted Peak Load (Percent)

Type of Resource	2008	2012	2016
Utility-Owned Resources	121	117	121
Long-Term Conventional Resource Contracts	0	0	0
Long-Term Renewable Resource Contracts	1	4	4
Dispatchable Demand-Side Resources (DDR)	1	1	1
Total	123	122	126

Source: Burbank Water & Power filing, February 13, 2007.

Redding Electric Utility

Redding Electric Utility's (REU) annual peak load in 2006 was 253 MW. Forecasted peak load in 2007 is 252 MW, in July. Redding is located in the SMUD/Western control area and is part of the Western sub-control area.

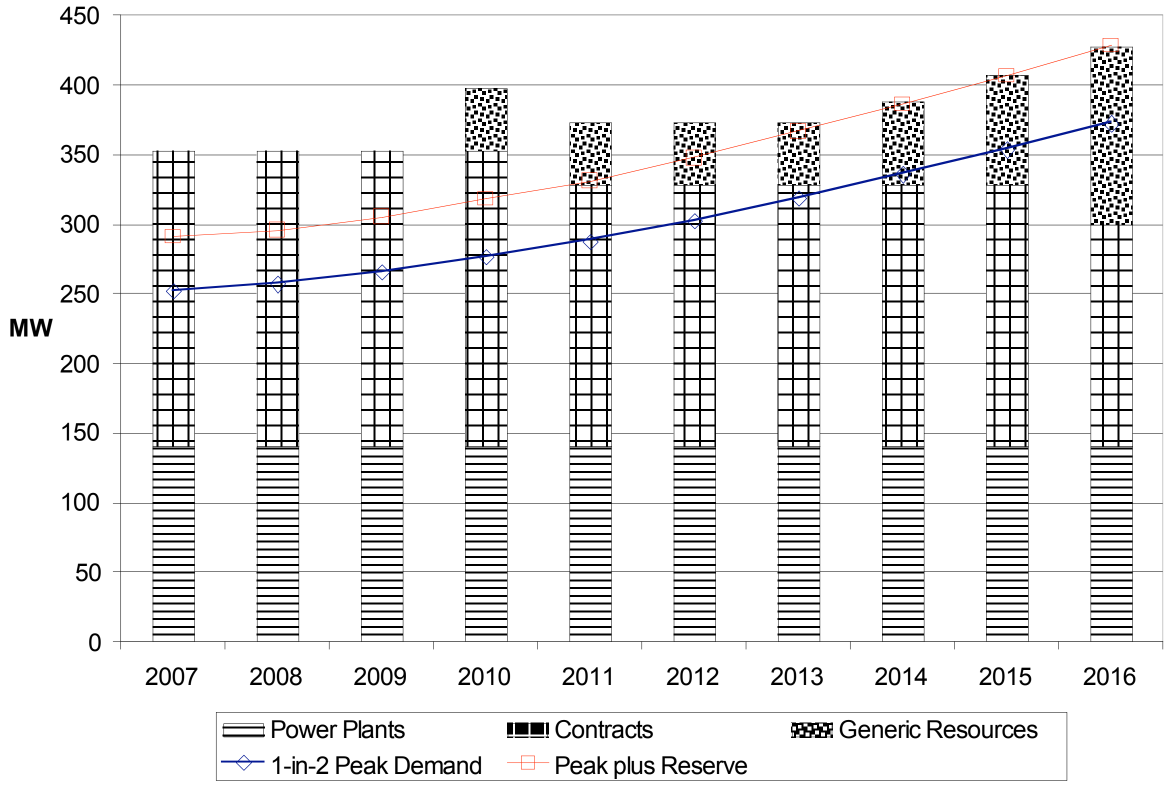
REU has historically used a 15 percent planning reserve margin based upon its highest monthly forecasted peak demand. While REU does not have formal criteria (adopted by the city of Redding's city council), future procurement activities and decisions are partly based upon REU's desire to maintain sufficient planning reserves.

As directed by Assembly Bill 380, REU intends to meet the requirements for resources adequacy established by the WECC. Currently, REU staff serve-on the WECC Loads and Resources Subcommittee "to aid in development of a methodology that can be applied throughout the Western Interconnection." (Redding Electric Utility filing, February 6, 2007)

As can be seen in **Figure 16**, Redding estimates demand growth at 45 percent over the planning period; this is a significantly higher rate of growth than that forecasted by Energy Commission staff.[21]

[21] The CED 2008 Draft forecast projects growth from 247 MW in 2007 to 278 MW in 2016 (12.6 percent).

Figure 16: Redding 10-Year Load/Resource Balance



Source: Redding Electric Utility filing, February 6, 2007.

The physical plants in Redding's portfolio include 139 MW of natural gas and 2 MW of hydroelectric facilities. The long-term resource contracts with American Electric Power, PacifiCorp Exchange, and San Juan provide 75 MW of capacity in 2008, falling to 22 MW in 2016. Long-term renewable contracts with Western, Big Horn Wind, RLC Industries, and renewable distributed generation provide a constant 138 MW of capacity (while still falling as a share of peak demand because of load growth).

Table 16 indicates the capacity associated with Redding's existing resources as shares of the utility's forecasted load growth.

Table 16: Redding Procurement Shares of Forecasted Peak Load (Percent)

Type of Resource	2008	2012	2016
Utility-Owned Resources	55	47	38
Long-Term Conventional Resource Contracts	29	17	6
Long-Term Renewable Resource Contracts	53	45	37
Total	137	109	81

Source: Redding Electric Utility filing, February 6, 2007.

CHAPTER 5: Resource Adequacy Protocols of Smaller Load-Serving Entities

While the majority of large and mid-sized publicly owned LSEs were required to submit 10-year resource plans to the Energy Commission of this report, the state's smaller LSEs were not required to do so. Each of them responded, however, to Energy Commission staff requests to provide narrative descriptions of resource adequacy protocols and policies. This chapter contains summaries of these submittals; it demonstrates the diversity of these entities with respect to size, nature of load obligation, generation and transmission assets, and relationships with other entities including energy suppliers, transmission providers, control area operators, and other LSEs.

Details regarding the peak loads and control areas of each of the state's publicly owned LSEs can be found in the tables in Appendix A.

Compact LSEs — 50 MW to 200 MW

City of Vernon Light and Power Department

Annual peak load in 2006 was 197 MW. Projected peak-hour load in 2007 is 203.2 MW in July. Vernon is located in the California ISO control area and is in the LA Basin load pocket.

The City of Vernon Light & Power Department provided its *Demand Forecast for 2007, Planning Reserve Margin and Qualifying Capacity Criteria,* previously submitted to the California ISO. This filing is directly related to Vernon's load within a Metered Subsystem (MSS), by agreement with the California ISO.

In April 2006, the Vernon City Council adopted a 15 percent reserve margin for planning. Like most LSEs in the California ISO, Vernon's resource adequacy statements define qualifying capacity (for resource adequacy) in terms of local conditions.

> Generating units and system units (but excluding Vernon diesel generating units) … shall be eligible to count as qualifying capacity. The amount of qualifying capacity of such units will be based on the projected dependable gross output capacity on a day when the ambient air temperature is 90 degrees Fahrenheit. (City of Vernon Demand Forecast cited above, page 7, filed with the Energy Commission on February 7, 2007)

Vernon develops both non-coincident and coincident peak load forecasts, using the latter to illustrate Vernon's share of the forecasted system peak in the California ISO control area. In its filings to the California ISO, Vernon's 15 percent planning reserve margin is applied to Vernon's coincident peak. Vernon explains:

> The California ISO's primary concern is with the time and amount of peak demand on the California ISO-controlled transmission system (the "system peak")…Vernon has adopted a rate structure and has succeeded in shifting the peak demand period for Vernon's system to a time that is generally earlier than the time of the California ISO system peak.

This means Vernon's 15 percent planning reserve margin is applied to an estimated 185.7 MW coincident system peak in July.

Vernon provided more specificity on transmission loss estimates than most LSEs. For imports from resources located outside the MSS area, Vernon estimated the following losses: 3.8 percent for Hoover, 3.7 percent for Palo Verde, 3.75 percent for all other imports, and 2 percent for any other qualifying capacity from within the control area but outside the MSS area.

City and County of San Francisco

Annual municipal peak load in 2006 was 120 MW. Most of the City and County of San Francisco's (CCSF) load serves its own wholesale needs, primarily the municipal load needed to serve San Francisco's city and county government facilities, the MUNI transit system, the San Francisco Airport (SFO) and the San Francisco Unified School and Community College districts. CCSF is also an existing LSE serving about a dozen retail end-users at the San Francisco International Airport in San Mateo County (SFO), retail customers on Treasure Island in San Francisco Bay, and minimal sales to the former Riverbank Army Ammunition Plant (located in the MID service territory). CCSF now acts as its own scheduling coordinator at the California ISO, a role formerly handled by PG&E.

CCSF is located in the California ISO control area; nearly all its loads are in the Greater Bay Area load pocket.

CCSF generates its own electricity at Hetch Hetchy, a hydroelectric project located on the Tuolumne River in the Sierra. CCSF owns transmission lines from the central Sierra to Newark in the East Bay. CCSF pays transmission fees to PG&E to wheel electricity from Newark to San Francisco and the San Mateo Peninsula. CCSF also pays distribution fees to PG&E, except for loads at SFO (which are connected at 115 kV). The CCSF loads at SFO are located in San Mateo County and are outside the California ISO-defined San Francisco local reliability sub-area.

The CCSF Interim Electric Utility Resource Adequacy Program was adopted by the San Francisco Public Utilities Commission in May 2006 (Resolution 06-0087). CCSF applies a 15 percent planning reserve margin to the entire amount of its municipal and retail load. CCSF does not apply a planning reserve margin to its wholesale obligations to the Modesto and Turlock Irrigation Districts but does subtract these obligations in determining the remaining capacity available to meet CCSF's remaining load.

For the summer months of 2007, CCSF counts on its Hetch Hetchy resources for 375 MW in May-July and 325 MW in August-September. CCSF also shows 146 MW of resources associated with its FERC Existing Transmission Contract (ETC) rights as defined in the CCSF/PG&E interconnection agreement. These FERC ETC resources decline to 121 MW in September. Firm sales to districts (MID and TID) vary monthly from 33 MW to 25 MW. With abundant resources and modest loads, CCSF shows a monthly resource adequacy capacity surplus of 400 MW in May, declining to 320 MW in late summer 2007.

Power and Water Resources Pooling Authority

The combined coincident annual peak load of Power and Water Resources Pooling Authority (PWRPA) members was 120 MW in 2006. (This LSE is listed slightly out of order in Appendix A.) In the year-ahead IRRP filing, based on an average water year, forecasted peak-hour load to be served by PWRPA in July 2007 was 68.9 MW. Because 2007 turned out to be a dry water year, actual pumping loads substantially greater. Actual peak demand in July 2007 was 92 MW.

PWRPA is in the California ISO control area with end-use loads in two zones: NP15 (north of path 15) and ZP26 (the zone of path 26).

PWRPA is composed of 15 public water purveyors that organized in 2004. The Authority's monthly peak power loads vary from 20 MW to 120 MW. The annual peak loads of individual participants vary from 2 MW to 35 MW. PWRPA includes nine irrigation districts: Banta-Carbona, Byron-Bethany, Glenn-Colusa, James, Lower Tule River, Provident, Princeton, West Stanislaus, and The West Side Irrigation District. PWRPA also includes the Arvin-Edison Water Storage District, Cawelo Water District, Santa Clara Valley Water District, Westlands Water District, Sonoma County Water Agency, and Reclamation District 108.

PWRPA provided its year-ahead IRRP, which was previously submitted to the California ISO. PWRPA uses a 15 percent planning reserve margin. The water agency and water district members of this Joint Power Authority get their energy from a combination of Western and other contract purchases (Western is counted upon to supply 69 MW in July 2007). PWRPA is its own scheduling coordinator at the California ISO, including all supplies from Western.

Colton Electric Utility Department

Annual peak load in 2006 was 87 MW. Forecast peak-hour load in 2007 is 89 MW in July. Colton is located in the California ISO control area and is in the LA Basin load pocket.

Colton uses a 15 percent planning reserve margin, resulting in a 102.35 MW firm peak LSE resource requirement for 2007. Coral Energy is its scheduling coordinator at the California ISO.

Colton provided the year-ahead IRRP previously submitted to the California ISO. As of November 2006, Colton's forward resource requirement was met with 44 MW of physical resources in the California ISO control area, 40 MW of unit-contingent resources from outside the California ISO control area, and 6 MW of non-unit contingent imports from outside the control area (large hydro from Hoover, nuclear from Palo Verde, and wind energy from PPM). Colton had no dispatchable demand response (DR) resources or LD contract resources. Unit-specific imports included 10 MW from gas-fired Magnolia in the LADWP control area and 30 MW from coal-fired San Juan Unit 3.

Merced Irrigation District

Merced Irrigation District's (Merced ID) annual peak load in 2006 was 82 MW. Forecasted peak load in 2007 is 82 MW in August. Merced ID is in the Turlock control area.

Merced ID uses a 15 percent planning reserve margin, which results in a 95 MW firm peak LSE resource requirement for August 2007.

For each month in 2007, Merced ID indicated an additional procurement need for capacity amounting to 8 MW to 17 MW. Turlock Irrigation District (TID) provides nearly all of Merced ID's supply needs. This includes all capacity, energy, or ancillary services needed in real time. The two supply contracts with TID both expire before summer 2008. Western supplies from 3 MW to 6 MW, depending on both the month and on hydro conditions. This is less than one-third of 1 percent of Western's 1,999 MW (nameplate) Central Valley and Washoe Project portfolios. The electricity from Western to Merced comes in through TID.

Merced has a 5 MW renewable energy contract through 2028 with PPM Energy, Inc. However, Merced does not take delivery of this energy in real time. Merced takes nominal and temporary ownership of the wind-powered energy from the High Winds 162 MW, 90-turbine project. Merced keeps the renewable attributes ("green tags") and resells the "brown energy" back to PPM.

Merced ID is the junior partner in the relatively new Turlock control area. Merced ID presently has neither utility-owned generation nor dispatchable DR resources. It has built its own distribution system and maintains its own transmission lines and substations, even though Merced ID's only electrical connection is with TID. It serves over 3,000 customers in eastern Merced County in a non-exclusive service territory and competes with PG&E for contracts with developers to serve new residential customers. Merced ID also sells (to PG&E) the electricity generated at its New Exchequer and McSwain hydroelectric power plants on the Merced River. This long-term sales contract expires in 2014.

Azusa Light & Water

Azusa Light & Power's annual peak load in 2006 was 63.3 MW on September 5. Forecast peak-hour load for 2007 is 65 MW in September. Azusa is in the California ISO control area and is in the LA Basin load pocket.

The city of Azusa has adopted a 15 percent planning reserve margin, resulting in a year-ahead forward commitment obligation of 75 MW. The year-ahead resource adequacy filing by Azusa showed the procurement of 89 MW in total capacity, equal to a planning reserve margin of 37 percent.

Azusa's resource portfolio is balanced in many dimensions: local generation and imports, owned and contractual resources, baseload and peaking resources, LD and renewable contracts, short-term and long-term supplies, must-take and call options, year-round and seasonal supply. Azusa has long held single-digit megawatt shares in large out-of-state generating stations including Hoover, Palo Verde, and San Juan.

Azusa resources include 4 MW of large hydro from Hoover under a 30-year contract that expires in 2017. Azusa has a 2 MW share of nuclear energy from Palo Verde, with rights to this capacity for the life of the project. Another Azusa baseload resource is 30 MW from coal-fired San Juan 3, with an ownership arrangement with SCPPA, which issued the bonds; after participants pay off the bonds, entitlement to this capacity will continue for the life of the project.

Azusa has purchased 20 MW in peak and super-peak call options from DWR. This supply is expected to come from DWR's Devil Canyon hydroelectric facility on the California Aqueduct's East Branch in San Bernardino. However, the energy from these contracts may flow from other sources. Azusa intends to fit its super-peak call option into the capacity paradigm used under the Market Reform and Technology Upgrade (MRTU) tariff to be implemented in early 2008.

Among its unit-specific supply resources, Azusa can call on 15 MW from Barclays Capital for a 6x16 contract product (energy that is typically delivered Monday through Saturday during the hours from 6 a.m. through 10 p.m.). And Azusa has a similar 25 MW LD contract with Public Service New Mexico (PNM) for a 6x16 energy product.

Among its renewable energy resources, Azusa has a 20-year 2 MW contract with PacifiCorp Power Marketing, which began in 2003. Though described as a wind project, it is listed on the IRRP filing as an LD contract since deliveries are shaped and scheduled using other resources.

For the year-ahead resource adequacy filing, Azusa procured 16 MW from Indigo 1, 2, and 3 exclusively for its resource adequacy purposes. Azusa cannot call upon Indigo for energy, and the generation owner must now make this capacity available to the California ISO (several other POUs in SP15 bought shares of Indigo through SCPPA solely to comply with resource adequacy tariff provisions).

Azusa does not serve load beyond its city boundaries; there are some pockets of load within Azusa that are still served by SCE, including some land incorporated into the city in 1995. There are development plans for this land that will add significant load for Azusa. Since late 2006, the city of Azusa has been serving about 150 kW of municipal departing load that was previously served by SCE.

Sub-Compact LSEs — 10 MW to 50 MW

City of Banning

The city of Banning's annual peak load in 2006 was 45 MW. The forecasted annual peak-hour load for 2007 is 48 MW. Banning is in the California ISO control area and is in the LA Basin load pocket.

Banning provided its year-ahead IRRP filing, which was previously submitted to the California ISO. Banning has multi-decade contracts or entitlements to import 2 MW of large hydro from Hoover, 2 MW of nuclear from Palo Verde, 2 MW of geothermal from Ormat in Nevada, and 20 MW of coal from San Juan Unit 3. In the IRRP filing, only San Juan is considered to be a unit-contingent import; the other three are non-unit contingent imports. Banning often sells 2 MW to 3 MW of shoulder and off-peak energy. This is usually sold into the day-ahead market.

Last year, acting with other SCPPA members, Banning procured 10 MW of resource adequacy capacity from Indigo. By the end of 2007, Banning will have spent $500,000 for this resource adequacy capacity. Indigo is not expected to serve any of Banning's load; the capacity was acquired specifically to meet IRRP requirements set by the California ISO tariff. Banning has no LD contracts and has no dispatchable DR resources in its portfolio.

Riverside serves as Banning's scheduling coordinator at the California ISO.

City of Shasta Lake

The city of Shasta Lake's annual peak load in 2006 was 33.6 MW. Shasta Lake is located in the SMUD/Western control area and is part of the Western sub-control area.

The city of Shasta Lake provided a filing that included information on bilateral contractual supplies from Western and Redding. Western provides 11.4 MW of "must take and pay" base resource and preference power (based on water year and as available). This contract expires at the end of 2024. Redding provides all other supplemental power, ancillary power, scheduling services, and transmission services. These energy products and services are provided wholesale by Redding under two contracts that expire at the end of 2007.

Shasta Lake is "actively looking to develop" demand-side resources.

Based on a new city of Shasta Lake boundary, this city utility expects 34 existing residential customers of PG&E to become customers of Shasta Lake. Peak demand of each customer is estimated to be 3 kW, so Shasta Lake reports that it expects 102 kW to depart PG&E's service for municipal service.

Truckee Donner Public Utility District

The Truckee Donner Public Utility District's annual peak load in 2006 was 31.2 MW. Estimated annual peak demand in 2007 is 34.4 MW in December. Truckee Donner is a network customer of the Sierra Pacific control area and is located in the Sierra Pacific Power control area, one of two major control areas in Nevada.

Truckee Donner provided 20-year load and resource plans, which were prepared in October 2006 for Sierra Pacific Power Company. These plans show a forecast peak of 51 MW in 2027. Truckee Donner is fully resourced through the end of 2007. The coal resource that was publicly discussed and then abandoned late last year would have come on-line in 2012. For 2007 at least, all of Truckee Donner's supplies are provided by Constellation Power Source, with Sierra Pacific providing transmission. The point of receipt is Gonder, Utah, via Sierra Pacific's IPP transmission line.

As part of its agreement with Sierra Pacific, Truckee Donner (as a network customer) "shall provide the transmission provider with a forecast for the following month specifying planned purchases, generation, maximum demand, total monthly energy, and operating reserves to be purchased …" Truckee Donner has the option to provide its own operating reserves, purchase its operating reserves from the transmission provider, or purchase those reserves from a third party.

Lassen Municipal Utilities District

Annual peak load in 2006 was 25.8 MW. Forecasted peak load in 2007 is 26.0 MW in July. Lassen Municipal Utilities District is in the California ISO control area.

Lassen is a “full load” customer of Western and has no generation of its own. All of Lassen’s supply comes via PG&E transmission at Westwood. Western serves as the scheduling coordinator at the California ISO.

Lassen has 11,500 customers, nearly all of them residential. Growth is expected to be negligible. Plumas-Sierra serves the area’s two state prisons and a new federal prison. Lassen has a high poverty level in its service area that requires significant outlays for rate assistance; the average customer uses 1,000 kWh per month. Public purpose programs include rebates for energy efficiency upgrades such as insulation and windows; there is also a move to broaden this traditional program to better assist low-income residents.

Surprise Valley Electrification Corporation

Annual peak load in 2006 was 25.0 MW. Surprise Valley is part of the Bonneville Power Administration (BPA) control area, the only California LSE with that status.

Surprise Valley buys all its power from BPA and is a 100 percent (full requirements) customer. Bonneville power is wheeled to Surprise Valley across PacifiCorp transmission, so its voltage is normally synchronized. Surprise Valley is considered to be part of the PacifiCorp control area only during moments when one of its switches is open. In other respects, Surprise Valley and PacifiCorp are interconnected by transmission and operate on the same electrical frequencies.

Surprise Valley provides electricity service to most of Modoc County, with some customers in both Oregon and Nevada. Surprise Valley is rural, with about two consumers per mile of line. Surprise Valley is summer peaking, with irrigation pumping making up 40 percent of its total peak load. Several overlapping areas in Modoc County are served by either PacifiCorp or Surprise Valley.

City of Needles

Annual peak load in 2006 was 19.0 MW in September. Monthly peak loads in non-summer months are typically 7 MW to 8 MW; peak loads rise sharply April and drop sharply in October. The city has a coordination agreement with Nevada Power to be in the Nevada Power control area.

The City of Needles gets a 6 MW package of allocations from the Parker-Davis Project in Western’s Desert Southwest Region, deliverable to the Mead Substation in Nevada. Mead is where, logically, Needles would take all its deliveries. However, during the summer months, Nevada Power limits the number of MW Needles can bring into Mead. Therefore, in June, July, and August, Needles must bring in purchased power at the Eldorado delivery point.

Needles is currently repackaging its Western allocations and is purchasing LD contracts from Pinnacle West or Arizona Public Service (APS), typically for three, six, or nine months at a time. Unfortunately for Needles, no counterparty has so far been willing to sign a long-term contract to deliver power for nine months of the year to Mead and three months of the year to Eldorado. The short-term LD contracts are fully acceptable to Nevada Power as a demonstration by Needles of resource adequacy. Nevada Power sells Needles all of its required reserves (spin and non-spin).

As of April 2006, the city had not yet adopted a formal resource adequacy policy. If Needles is short or underscheduled in real time, Nevada Power will provide the imbalance energy needed to maintain Needles' load/resource balance. The price of this supply varies; in April 2007 it was about $70 per MWh. From Needles' perspective, Nevada Power's tariff strongly discourages overscheduled events. If Needles is long on power compared to demand, Nevada Power will absorb and integrate that surplus and pay Needles somewhere between $10 and $17 per MWh. Therefore, it is financially much worse for Needles to be long rather than short. Since perfect balance is never possible, the ideal for Needles is to always be "just short" for day-ahead scheduling into real-time operations. This tariff is in place to protect Nevada Power from merchant generators that might otherwise dump excess power in that direction. But as a consequence, Needles has no incentive to plan a reserve margin that would lead to procurement of 115 percent of its forecasted load.

The scheduling coordinator for Needles is the Phoenix office of Western's Desert Southwest Region. But neither Western nor Nevada Power deals directly with the California ISO. So when Needles purchases power from a supplier in California, Needles can end up paying three scheduling coordinators to move the power the last 40 miles.

To address this long-term reliability challenge (and in the hope of saving about $10 per MWh), Needles and Aha Macav Power Service (discussed below) have built a 4-mile transmission line across the Colorado River. This 69 kV line will also provide Needles with a connection to Western's Parker-Davis 500 kV line. Needles anticipates that it may then shift from Nevada Power's control area to Western's Desert Southwest control area.

Trinity Public Utility District

Annual peak load in 2006 was 18 MW. The Trinity Public Utility District (Trinity PUD) is part of the California ISO control area.

Trinity PUD acquires all of its energy from Western and is resource adequate for decades to come. By federal law, Trinity could take up to 25 percent of the electricity generated within the county by the Central Valley Project, though only for consumption within the county.

The power from Trinity Dam is currently sent southeast to the Sacramento Valley over Western's transmission to Cottonwood Substation. The electricity then travels northwest back into Trinity County over PG&E's transmission lines. Outages on PG&E's transmission lines are the number one cause of outages and unserved energy, according to Trinity PUD's management. To improve local reliability, Trinity PUD is now constructing, under the auspices of Western, its own 5.3-mile 60 kV transmission line that will connect hydroelectric resources at Trinity Dam with Trinity PUD's substation in Weaverville. After this new transmission line is completed, about 90 percent of Trinity PUD load will be independent of PG&E transmission, and the utility will be able to transfer to the SMUD/Western control area.

After lengthy settlement negotiations, the California ISO signed a "Small UDC" (utility distribution company) operating agreement protecting Trinity PUD from an assigned share of rotating outages if and when California ISO system resources are inadequate.[22]

Moreno Valley Utilities

Annual peak load in 2006 was 15.7 MW. Forecasted peak-hour load in 2007 is 12.7 MW in July. Moreno Valley Utilities (MVU or Moreno Valley) is in the California ISO control area and is located in the LA Basin load pocket. Moreno Valley uses Sempra Solutions both as its scheduling coordinator at the California ISO and as its sole provider of wholesale energy products, including LD contracts.

MVU provided one of its summer 2007 IRRP filings that was previously submitted to the California ISO. This IRRP filing indicated that additional procurement was needed to meet its peak summer loads. Moreno Valley has not yet adopted a formal planning reserve margin or resource adequacy policy.

Moreno Valley began service in Riverside County in 2004 serving new residential and commercial customers in a "greenfields" territory.[23] Moreno Valley has a 17-year contract with Enco Utility Services to provide planning, engineering, and electricity distribution services.

A new 115 kV substation is under construction. Construction of a new distribution system that will take off from an SCE 115 kV line was begun in February. As of February 2007, Moreno Valley's completed distribution lines totaled 4,300 meters.

City of Corona Department of Water and Power

The city of Corona's annual peak load in 2006 was 28.0 MW; this number includes both POU and ESP loads of about 14 MW each.[24] Forecast peak-hour load in 2007 for the POU in the city Department of Water and Power is 13.1 MW in July. Corona is in the California ISO control area and is in the LA Basin load pocket.

[22] See http://www.caiso.com/docs/2005/05/20/2005052010580122403.pdf
[23] See http://www.moreno-valley.ca.us/resident_services/utilities/pdfs/greenfield.pdf
[24] The city of Corona has both a public utility and an energy service provider; the latter competes with SCE for end-use customers.

According to the year-ahead IRRP filing that was submitted to the California ISO, Corona as a POU has adopted a planning reserve margin of 15 percent. Coral Power LLC is the scheduling coordinator at the California ISO.

Eastside Power Authority

Annual peak load in 2006 was 13.0 MW. Forecasted peak-hour load in 2007 is 15.8 MW in July. The Eastside Power Authority (Eastside) is in the California ISO control area and is partly in the Greater Fresno load pocket.

Eastside has adopted a planning reserve margin of 15 percent according to its year-ahead IRRP filing, which was submitted to the California ISO. Eastside is a joint power authority in the San Joaquin Valley, which is similar to but smaller than the PWRPA.

Eastside does not have an exclusive LSE service territory. It has six end-use customers: three irrigation districts and three water districts. Five of these six districts have rights to public power from Western. The six have different load factors at different times of the year. These districts are located in the PG&E and SCE service territories.

Eastside has a 20-year supply contract with Western, which serves as Eastside's scheduling coordinator at the California ISO. In addition to Western (as a primary supplier), Eastside buys market power and has bought power from both the Constellation and California ISO markets. Eastside also had a contract with Shell and Constellation for the 2 MW reserves that were part of its resource adequacy compliance in 2006. In the future, these contracts will bring Eastside supplies up to 15 MW.

Eastside has been in frequent discussions about certain pumping loads that could be considered to be emergency interruptible resources. In its IRRP filing, Eastside identified 2.06 MW of Dispatchable Demand Response Program resources that would be "available post-'Stage 2' at the cost of $400/MWh." These emergency DR resources could be called upon by the California ISO for both local and system reliability. However, a complete shutoff of electricity would damage their pumps, with unrecoverable costs. Eastside is willing to interrupt pumping load as a "last resort" to avoid blackouts: for example, after a California ISO declaration of a Stage 2 emergency, to preclude a Stage 3 emergency.

Anza Electric Cooperative, Inc.

The Anza Electric Cooperative, Inc. (Anza) annual peak load last summer was 12.5 MW. Forecasted peak-hour load in 2007 is 10.39 MW in August. Anza acts as its own local regulatory authority, has adopted a 12 percent planning reserve margin, and is in the California ISO control area.

The year-ahead IRRP for Anza Electric was provided by the Arizona Electric Power Cooperative (AEPCO), from which the utility buys all its supplies. Anza has a 10 MW delivery contract and has just added a new 4 MW supply contract. Together, these contracts amount to an all-requirements delivery obligation to Anza. Anza Electric is not supplied from any specific resource; all of Anza's supplies come from AEPCO system resources that include coal, gas, and hydro.

AEPCO, as a cooperative wholesale power provider, pays fees to SCE for delivering electricity across SCE wires to Anza. Anza takes delivery of its energy supply at the Mountain Center Switch Station. Though Anza's loads are included in Edison's UDC loads, Anza has no direct business transactions with SCE. AEPCO handles any needed transactions with SCE and serves as the scheduling coordinator for Anza at the California ISO.

Anza/AEPCO have grandfathered transmission rights for 10 MW on the Mead-to-Valley path and firm transmission rights on the SCE system, from Valley to the Mountain Center Switch Station. Since the 12.5 MW peak load in 2006, AEPCO has been working with SW Transco for the transmission portion that is greater than 10 MW. For the piece into Anza above 10 MW, AEPCO is looking for a scheduling coordinator to schedule its coordinator trades. For 2007, AEPCO purchases in SP15 before the beginning of each month to supply the Anza load above 10 MW.

Anza's rural service territory is in a relatively remote area, surrounded by BLM lands, wilderness, and roadless state park land to the south (Coyote Canyon is in Anza-Borrego Desert State Park). Anza is supplied by a single transmission (or subtransmission) line, which has been a reliability concern. However, the costs and difficulties associated with constructing a second transmission line into Anza have so far been prohibitive.

Rancho Cucamonga Municipal Utilities

Annual peak load in 2006 was 12.0 MW. Rancho Cucamonga Municipal Utilities (Rancho Cucamonga) is in the California ISO control area and is in the LA Basin load pocket.

Rancho Cucamonga provided its year-ahead IRRP filing, which was submitted to the California ISO. Rancho Cucamonga has adopted a 7 percent planning reserve margin, and has both a mix of physical resources under contract, and multi-year system power contracts with entities including Coral Energy and the city of Vernon. LD contracts have been preferred for certain financial and reliability benefits and performance.

Pilot Power is the utility's scheduling coordinator at the California ISO. The utility served its first retail end-use electricity customer in June 2004. At buildout, Rancho Cucamonga projects its peak load will be 20 MW to 21 MW. All of its retail LSE customers are commercial (no industrial or residential customers), a trend that is expected to continue.

Mini-Compact LSEs — Under 10 MW

City of Cerritos

Annual peak load in 2006 was 9.9981 MW in September. The city of Cerritos' forecasted peak-hour load in 2007 is 11.3 MW in July, August, and September. Cerritos is in the LA Basin load pocket.

Cerritos, a community aggregator,[25] relies upon the Magnolia plant to meet its entire forecast load plus a 15 percent planning reserve margin. The power sales agreement for the output from Magnolia can be extended at the end of 40 years, and it is tied to debt service. However, Cerritos does have a partial requirements contract with Coral Power to purchase power when Magnolia is down or derated below its entitlement needs. This year Coral Energy also serves as the city's scheduling coordinator.

Last year Cerritos had an LD supply contract with PPM, and PPM served as the scheduling coordinator. These contracts have been terminated.

City of Industry

The annual peak load in 2006 was 6 MW. The forecasted peak-hour load in 2007 is 6 MW in September. The City of Industry is in the California ISO control area, and is in the LA Basin load pocket. Industry uses Sempra as its scheduling coordinator.

Acting as the local regulatory authority, according to its IRRP filing, the City of Industry has adopted a 10 percent planning reserve margin. The September 2007 planning reserve margin of 10 percent is 0.6 MW. According to its undated IRRP filing, the City of Industry had already procured 6.84 MW, which is equal to a year-ahead 14 percent planning reserve margin.

For the year-ahead IRRP filing, the City of Industry reported three LD contract supplies totaling 5.8 MW. Industry can also reduce peak loads by calling on 2 MW of dispatchable demand response at the Industry Hills Golf Club and the Pacific Palms Conference Resort.

[25] By statute. Such an entity is distinct from a Community Choice Aggregator, over which the CPUC has jurisdiction.

Morongo Casino (Morongo Band of Mission Indians)

Annual peak load in 2006 was 5.3 MW. The sole facility used to serve this load is not connected to the transmission grid.

The Morongo Band of Mission Indians own and operate a stand-alone cogeneration plant in the city of Banning, in Riverside County. The Morongo Casino Cogeneration Facility, built in 2004, supplies electricity to a casino resort and is not connected to the grid. The plant provides all the electricity consumed at the casino, three restaurants, a 28-story hotel, and a large parking garage. Waste heat is recovered to heat the casino and hotel and generate chilled water. No other commercial, industrial, or residential loads are presently served, although this is a possibility in the future.

The Morongo Band's first casino, begun in 1983, had frequent low-voltage outages. During design of the cogeneration plant, peak loads at the new casino were estimated to be 4.62 MW, with minimum electric loads of 3.62 MW. To allow for 15 percent future load growth, the power system was planned to serve peak loads up to 5.3 MW, with an additional 6 MW of diesel-fired backup generation. The power plant system uses four natural gas-fired 2 MW Caterpillar G3520C engines. Three 2 MW diesel-fired Caterpillar 3516B engines provide the backup system. All 8 MW of gas generation and 6 MW of diesel generation are on the same bus at 12 kV. Emissions are fully controlled to meet the standards of the South Coast Air Quality Management District.

The Morongo Band also built a bottling plant on its lands for Arrowhead Mountain Spring Water, with electric loads supplied in part by another 3 MW cogeneration plant. But the water bottling plant and its 3 MW cogeneration plant are interconnected to the grid within SCE's service territory.

Pittsburg, City of (also known as Pittsburg Power Co.)

Annual peak load in 2006 was 4.5 MW for the city of Pittsburg (Pittsburg), which serves load in a part of the city of Vallejo. Retail electricity customers know their LSE as Island Energy. Pittsburg is in the California ISO control area and is in the Greater Bay Area load pocket.

Pittsburg has a supply contract with Western that expires in 2024. Western meets all of Pittsburg's requirements, so this LSE has neither a formal resource adequacy policy nor a practical need for one. Western is the scheduling coordinator.

Pittsburg owns the distribution system on Vallejo's Mare Island, which was obtained from the U.S. Navy. The distribution system on Mare Island is massive, built for the industrial energy needs of the Naval Shipyard. Compared to this infrastructure capacity, actual energy deliveries are quite low. Losses in the distribution system amount to 19 to 20 percent. It is believed that nothing can be (economically) done to reduce distribution losses and unaccounted for energy without substantial load growth. There are no firm plans to serve load within the city of Pittsburg, though this is considered to be a distant possibility.

When the Navy decommissioned Mare Island, the city of Vallejo did not want to become the electric service provider, and PG&E did not want to take over retail deliveries. Power from PG&E transmission is delivered to Station H at the south end of Mare Island.

Victorville Municipal Utility Services

Annual peak load in 2006 was 3.6 MW. The forecasted peak-hour load in 2008 is between 5 and 8 MW.

Since George Air Force Base was decommissioned in 2000, Victorville has been providing electricity to the Southern California Logistics Airport and another development area, neither of which is connected to the transmission grid. These two areas are served by 12 small generators, mostly diesel and some gas. Victorville is considering the use of biodiesel fuel (such as B20) to generate some of its electricity from renewable fuels. The utility does not yet have a substation.

On this very small independent system, Victorville must be self-sufficient, with adequate power even during unscheduled maintenance or generator outages. To maintain its own reserve margins, Victorville does everything to an “N+1” engineering standard. That means that Victorville schedules and operates most of the time with 100 percent planning and operating reserve margins. Victorville expects to add generation as its load grows.

Valley Electric Association

For the entire Nevada/California service area of the Valley Electric Association (Valley), the 2006 peak load was 115 MW in September; the January 2007 peak load was 124 MW. Annual peak loads now can occur in winter or summer. For California customers alone, the 2006 annual peak load in September and was 2.8 MW. For Valley’s California customers, the January 2007 peak load was 58 kW. Most of the September peak in California is driven by two irrigators in Fish Lake. Nevada Power is the control area for Valley.

These annual peak numbers do not include end-use customers in Death Valley (Furnace Creek Ranch and Furnace Creek Inn) and south of Death Valley (in and around Tecopah), who receive electricity and monthly statements from Valley. These customers are officially in the SCE service territory. By longstanding agreement, SCE delivers some energy to end-use customers in Nevada that are officially located in Valley’s service territory. Technically, Valley and SCE “trade energy.” This exchange allows Valley and SCE to provide electricity deliveries to a few remote customers in rural areas that lack the wire connections for the LSE assigned to that service territory. Valley does not include either of these customer groups in its own load.

Valley is connected with Western at Mead and tied to Nevada Power at Jackass Flat (a test site). Valley is totally separate from Nevada Power's transmission system. Valley owns 87 miles of 230 kV transmission line from Mead and 75 miles from Amargosa. Western provides the supply, manages the interconnection, and provides voltage support. Valley also monitors voltages. The supply from Western at Mead and Amargosa does not have any reserves; it is all delivered as firm energy. Nevada Power charges Valley 5 percent of what it estimates Valley's reserves should be. On occasion Valley calls upon those reserves to meet its loads.

Valley has no generation of its own. It relies on contracts and market purchases. Purchases currently supply about 8 to 10 percent of Valley's energy needs. Valley now uses UEMS out of Utah for some baseload energy and is considering purchasing renewables with partners.

Port of Stockton

Annual peak load in 2006 was 2.8 MW. The Port of Stockton (Port) is in the California ISO control area and is in the Stockton load pocket.

Sempra Energy Solutions provides all of the Port's electricity supplies and requirements, including acting as scheduling coordinator at the California ISO. The Port recently renewed its contract with Sempra through May 2011. Sempra provides 2.0 MW under this contract and arranges procurement for additional fractions when load exceeds 2.0 MW.

The Port is one of three mini-compact POUs embedded in PG&E's distribution system. The Port anticipates some load growth over the next few years and is considering taking 60 kV service from the grid at some future date by building its own substation on Rough & Ready Island. If this substation is built, the Port will still pay transmission fees to PG&E and be included in PG&E's loads for transmission planning.

The city of Stockton is trying to lease some of its land at the Port to companies planning to develop liquid biodiesel fuels for transportation energy markets. The city redevelopment agency is also investigating the possibility of developing a biodiesel power plant of around 45 MW at the port that could provide all of the port's supply, along with surplus capacity for sale to wholesale markets.

Hercules Municipal Utility

Annual peak load in 2006 was 2.7 MW. The city of Hercules is in the California ISO control area and is in the Greater Bay Area load pocket.

The Hercules Municipal Utility (Hercules) procures all of its electricity through long-term, month-ahead, and day-ahead contracts. Hercules is currently negotiating for power purchases through 2009. Periods for deliveries are both on-peak and off-peak, as defined by NERC. The utility has a very high (68 percent) load factor. Sempra serves as scheduling coordinator for Hercules at the California ISO. Hercules has no utility-owned generation, and there are no DG or DR resources in the service area.

Hercules has adopted a 7 percent operating reserve margin as a self-requirement and forecasts its own load.

Hercules has been a municipal utility for about four years. Load is mostly residential. Hercules does not have an exclusive distribution service area and competes head-to-head with PG&E for distribution service to newly developing areas; Hercules has doubled its housing load every year for the past three years. New housing construction occurs in spring and summer, and these new homes are often not occupied until the following winter. Consequently, Hercules has been winter peaking every year so far, on a calendar-year basis. However, each subsequent summer peak has exceeded the winter peak in the prior calendar year. After the currently high *rate* of growth declines, Hercules could eventually become a heat-driven summer peaking utility.

Hercules takes power from the PG&E transmission system at PG&E's Christie Substation, so Hercules pays transmission and distribution fees to PG&E. Beyond the Christie Substation, Hercules has its own distribution system with 26 MW of distribution capacity. This is a highly reliable distribution system, with zero overhead wires. Hercules does track distribution outages, which it claims are orders of magnitude less frequent than PG&E's distribution outages in the area.

In 2006 Hercules was "100 percent green," a claim made possible by purchasing "green tags," a tradable form of "renewable energy credits" or RECs, which are in use among a few California POUs. However, the price of green tags has tripled in 2007 and it may not be prudent to maintain this standard indefinitely. Hercules is pursuing ownership interest in a wind farm, and in possible exchange agreements with larger POUs.

The Hercules staff has developed formal resource adequacy standards and protocols. This draft policy has been presented to the city council for consideration and is likely to be adopted later this year.

Aha Macav Power Service (Fort Mojave Tribe)

For 2006, annual peak load in California was between 1 MW and 1.5 MW.

Aha Macav Power Service (AMPS) is located in the Western Area Lower Colorado (WALC) control area operated by the Western Area Power Administration, Desert

Southwest Customer Service Region. This is a unique status among California LSEs as shown in Appendix Table A-4. The WALC control center is in Phoenix, Arizona. AMPS is wholly owned and operated by the Fort Mojave Tribe. The Fort Mojave Reservation covers more than 22,000 acres in parts of Arizona, Nevada, and California. AMPS was formed in 1991 and began serving residential loads in Arizona in a new tribal-owned subdivision. In 2006, AMPS began serving its tribal headquarters and a small tribal village on reservation land within the city of Needles, California. This very small load was formally served by the city of Needles Department of Public Utilities (discussed above).

AMPS began providing this service in California after a new four-mile section of 69 kV transmission line was completed. This line crosses the Colorado River and connects with an older substation on reservation land in Arizona. AMPS anticipates load growth in all three states and expects its loads in Nevada to grow from 2 to 150 MW within 20 years.

Shelter Cove Resort Improvement District

Annual peak load in 2006 was 0.7 MW. The Shelter Cove Resort Improvement District (Shelter Cove) is in the California ISO control area and is in the Humboldt load pocket.

Shelter Cove buys all its power from Western, which serves as its scheduling coordinator. Before this, Shelter Cove belonged to the NCPA Power Pool.

This publicly owned LSE is embedded within PG&E’s transmission loads and distribution system. Shelter Cove is a residential community located in southern Humboldt County on a remote coastline. The formal name of this LSE is Humboldt County Resort Improvement District #1. As a resort improvement district, this utility is unique to California. This district is a nonprofit public utility district established in 1965 to provide Shelter Cove with electricity, water, and wastewater treatment. The district manages a golf course, a day-use airport, and recreation greenbelt areas. The district also provides emergency services, including fire protection and medical aid.

The annual peak load for Shelter Cove is generally in December. The Shelter Cove website explains its long-term need for additional electricity supplies.

McAllister Ranch Irrigation District

McAllister Ranch Irrigation District (McAllister Ranch) began electric service as an LSE in February 2007. Forecasted peak load for 2007 is well under 1 MW. McAllister Ranch is in the California ISO control area and is in the Kern load pocket.

California’s smallest publicly owned LSE, it is located on the southwest edge of the city of Bakersfield. This 2,070-acre parcel is being developed by SunCal Companies for 6,000 residential units at buildout.

On its first day of operation, McAllister Ranch delivered energy to a single load, a 5-ton air conditioning unit at a modular welcome center. At first McAllister Ranch was allowed to simply “lean on the system” with its *de minimus* loads,[26] paying the California ISO for imbalance energy. Now McAllister Ranch uses Sempra Energy Solutions as its scheduling coordinator.

McAllister Ranch is interested in pursuing on-site renewable energy sources, especially solar photovoltaic. The subsidies, tax credits, accelerated depreciation, and marketing benefits make new developments with integrated solar distributed generation especially attractive. Some benefits will accrue to the developers, some to the LSE, and some to the new homeowners, according to Enco and SunCal management.

[26] A *de minimus* load has been defined in the California ISO tariff on resource adequacy as a load with an annual peak of less than 1.0 MW. Such LSEs are still required to file an annual resource adequacy plan but are exempt from filing month-ahead updates to the annual plan. LSEs with *de minimus* loads are also exempt from requirements to file day-ahead resource schedules and an annual demand forecast.

CHAPTER 6: Entities Without a Formal Resource Adequacy Obligation

For this report, a few entities were identified that do not have a load-serving obligation requiring procurement plans for electricity resources. This *ad hoc* list of non-LSEs includes four end-users, two end-use aggregators, and two entities that are organizing to become LSEs in the near future (an existing irrigation district and a newly formed community choice aggregator). It also includes three local entities technically authorized to furnish electricity on a retail basis but unlikely to become LSEs in the foreseeable future.

Besides being authorized to furnish electricity to end-use customers, an active load-*serving* entity must be engaged in at least one of five basic *services*: load forecasting, resource planning, resource procurement, scheduling, and coordination with a control area for real-time and contingency operations. One of the entities discussed below, Bay Area Rapid Transit (BART), does resource procurement; two others do resource planning. But most of the entities discussed in this chapter do not pass this screening criterion of providing at least one basic service. It appears, generally, that LSEs with annual peaks greater than 50 MW provide all five of these services.

Some of the entities described in this chapter, including Escondido, Calaveras, and Tuolumne, are sometimes listed elsewhere as “utilities” with energy sales. They may in fact be utilities for reporting energy sales data to the Energy Information Agency of the U.S. Department of Energy. The entities discussed below might be deemed LSEs in other proceedings, including those related to energy efficiency or greenhouse gas emissions. However, if the factual circumstances reported below remain unchanged, there would be no resource adequacy “progress” to report for these entities in future years.

It is worth noting that not every load has a load-serving entity. BART is one such load that procures energy for its own consumption. Semitropic Water Agency is a unique end-use load that owns more infrastructure than many of the mini-compact LSEs discussed at the end of Chapter 5. These two end-users are utility-scale examples of grid-connected loads that appear on the UDC (distribution) or PTO (transmission) loads of an IOU; but these loads would not appear, at least not in their entirety, as forecasted loads of LSEs. This circumstance where potential loads are not served by an LSE is also true, to some extent, for all LSE customers with distributed generation (DG) facilities, though the statewide numbers for DG are not yet great enough to be of concern for detailed resource adequacy rulemaking.

End-Users

Bay Area Rapid Transit

BART's annual non-coincident peak load in 2006 was 84 MW. At the time of the California ISO control area's coincident peak in 2006, BART's load was 70 MW. BART is in the California ISO control area.

BART procures its own energy supplies from Western and NCPA. PG&E serves as BART's scheduling coordinator at the California ISO.

BART's peak load occurs in the in the late afternoon 5 p.m. to 6 p.m. rush hour (HE 18). All of BART's trains include regenerative braking, a mechanism that reduces vehicle speed by converting some of its kinetic energy into electrical energy that is fed back into the power system for other vehicles. This appears to be most effective during rush hour when more trains run and there is a greater likelihood that another nearby train could take power from the third rail. This improved energy efficiency performance during the peak afternoon rush hour is about 5 percent greater than the average efficiency for all hours.

City of Escondido

The city of Escondido pays for the electricity that SDG&E provides to a single meter on the Rincon Indian Reservation, several miles northeast of Escondido. The energy consumed on the Rincon Reservation averages 36 MWh per year.

Escondido has contractual energy obligations to the Rincon Reservation through a contract dating back to at least 1924, according to the city's utilities administration. Escondido books power sales to Rincon as if it were an electricity wholesaler and receives about $6,000 annually from the Rincon Reservation as partial payment for electricity consumed on the reservation. This arrangement fulfills the terms of the long-term contract that conveys to Escondido certain consumptive water rights for stream flows out of the reservation, which are an essential component of Escondido's municipal water supply.

For reporting on resource adequacy progress by publicly owned utilities, Escondido is not considered to be an LSE. It does not appear on the California ISO's list of non-CPUC jurisdictional LSEs. Escondido has no obligations for any of the basic LSE services discussed above. Using this screening criteria, Escondido is not therefore considered to be an LSE. For the Rincon Reservation, SDG&E is the LSE, including both load forecasting and procurement obligations and resource adequacy demonstrations at the California ISO. Energy supplies are procured, scheduled, and delivered to the Rincon Reservation as they are to any other SDG&E end-use customer. To SDG&E, for billing purposes, the city of Escondido is simply the delegated ratepayer. Collecting energy payments from another end-use customer does not, by itself, establish a forward obligation for supply resources.

Metropolitan Water District of Southern California

The Metropolitan Water District (MWD) does not serve retail loads or the end-use loads of other electricity customers. Therefore, by most definitions MWD is not considered to be a load-serving entity. However, MWD voluntarily provided information that describes how it manages service for its wholesale load, which is entirely related to its requirements for pumping Colorado River water and conveyance on its aqueduct.

Under an existing agreement described below, SCE serves as the scheduling coordinator at the California ISO for MWD's wholesale pumping load and generating resources used to meet that load. The following summary paragraphs are based on statements by MWD at the Energy Commission's May 15, 2006, public workshop on resource adequacy and describe how MWD serves its wholesale pumping load on its Colorado River Aqueduct (CRA).

One of the major sources of water for MWD is the Colorado River, conveyed over 240 miles by aqueduct. There are five pumping plants along the aqueduct, each equipped with nine pumps to lift the water over and through the mountains west of the Colorado River and through the Mojave Desert. The aqueduct pump loads are referred to as "wholesale" to distinguish them from other MWD loads that receive retail service. MWD's retail loads, including water treatment plants and office facilities, are served by SCE and other publicly owned utilities.

MWD's CRA electric system is designed to meet maximum pumping load of about 320 MW. In 2006, annual peak CRA pump load was 222 MW. (This pump load is included in the total annual peak load of SCE as listed in Appendix A.) To supply its aqueduct pump load, MWD has entered into long-term contracts for power from the Hoover Dam and Parker Dam power plants. MWD has rights for up to nearly 310 MW from these two facilities. In addition, MWD has the ability to interrupt up to 110 MW of pumping at its Whitsett (Intake) pumping plant at Lake Havasu and its Gene pumping plant two miles west of the lake, for a limited time without losing or spilling water from the aqueduct.

MWD's CRA pump loads are currently served through an integration and energy exchange contract with SCE that has been in place since 1987. Under this agreement SCE combines the aqueduct's pump loads and resources with SCE's own retail loads and resources. SCE schedules MWD's Hoover and Parker resources and has the right to request MWD's interruption of up to 110 megawatts of pump loads up to 20 times per year. Therefore, for resource adequacy purposes, the requirements for MWD's CRA pumping load are satisfied by MWD and SCE. SCE includes MWD's CRA pumping load in its aggregated resource adequacy submittals.

In the LA Basin, MWD has 16 small hydroelectric facilities for power recovery along distribution conduits with total dependable capacity of about 122 MW. The largest-capacity facility is Etiwanda, with 23.9 MW. Eight of these renewable energy resources are interconnected with SCE's distribution system and included among SCE's renewable energy supply resources.

Semitropic Water Storage District

Based in Wasco in Kern County, Semitropic Water Storage District (Semitropic) has specialized in groundwater banking programs for more than 10 years. Semitropic does not supply retail energy to other end-use customers.

Semitropic does have about 4 MW of canal-based hydro and 1 MW of solar PV generation. These facilities reduce the amounts of retail energy that Semitropic purchases from PG&E, its LSE. Semitropic also has about 4 MW of natural gas generation, but these are relatively inefficient combustion peaker units that are not routinely scheduled for operation.

As an end-use customer of PG&E, Semitropic has some unique self-generation assets including more than 14 miles of transmission lines, three substations, and distribution lines. Using its transmission and distribution facilities, Semitropic is able to wheel the electricity from its self-generation resources to its pump loads. However, at all hours of the year, Semitropic is a net consumer of energy from both PG&E and the grid. Peak demand in 2006 was about 14 MW.

Semitropic does not have any of the obligations of a fully functioning LSE: load forecasting, resource planning, resource procurement, resource adequacy filings, resource scheduling, or communications with a control area operator. Consequently, using the definitions described above for the city of Escondido and for purposes of this report on resource adequacy, Semitropic is considered to be an end-user, not an LSE.

End-Use Aggregators

Calaveras Public Power Agency and Tuolumne County Public Power Agency

In the California ISO control area, there are two entities that have, on rare occasions, been nominally identified as LSEs but are here considered to be end-use aggregators. These two entities are the Calaveras Public Power Agency (Calaveras) and the Tuolumne County Public Power Agency (Tuolumne).

Calaveras and Tuolumne are both local public agencies with several end-use customers; each has individual entitlements to federal power. Western provides all the electricity for end-users and serves as portfolio manager for all filings at the California ISO. Western is, for all practical purposes, the designated LSE for all Calaveras and Tuolumne end-users. In this role, Western serves as scheduling coordinator at the California ISO.

Neither Calaveras nor Tuolumne has any distribution infrastructure. Neither Calaveras nor Tuolumne has a resource planning role, a resource procurement responsibility, or a resource adequacy obligation. The end-use hourly peak loads of these two entities is only rarely measured or reported. Neither entity forecasts or monitors its loads, nor are these tasks necessary. Neither entity schedules resources or communicates with the California ISO.

For Calaveras, annual peak loads in 2006 were estimated to be about 7 MW. The annual peak loads in 2006 for Tuolumne were estimated to be about 26 MW. All the end-use loads are embedded in PG&E's utility distribution company loads.

The obligations of Calaveras and Tuolumne are primarily focused on providing payments to Western for the monthly metered energy consumed by their various members.

All together, the customers of Calaveras Public Power Agency consume about 30 million kWh annually, with a combined entitlement to 55 million kWh. All are "number 1" preference customers, second only to the system needs of Western. Calaveras does not consider itself to be a load-serving entity and agrees that a better term would be "end-use aggregator".

Tuolumne does not consider itself to be an LSE, either, and also agrees that a better term would be end-use aggregator. Tuolumne has a contract with PG&E that includes a provision that its load must meet certain demonstration requirements (included in Tuolumne's aggregation of end-users). Each individual load must be at least 5 kW (and it may have to be in existence for one year before switching from PG&E to Tuolumne). For many of Tuolumne's members, which now number 30, this has been a one-time switch from PG&E. By agreement, these members are not subject to departing load fees. A member that leases space and changes to new leased space can move the account without appearing to transfer or depart load.

Potential Future LSEs

Two entities in the San Joaquin Valley have publicly announced plans to become LSEs. One is an existing irrigation district with water storage and conveyance facilities, including existing hydroelectric generation. The other is a new entity that has formed a partnership to become a community choice aggregator. Both entities need additional permission or authorization before they assume local load-serving obligations. Consequently, neither entity had a resource adequacy obligation as of spring 2007.

San Joaquin Valley Power Authority

This prospective community choice aggregator in the Greater Fresno Area formed in November 2006 following a joint powers agreement. The San Joaquin Valley Power Authority (Authority) is a partnership formed by Kings County, the Kings River Conservation District (KRCD), and 12 local cities: Clovis, Corcoran, Dinuba, Fresno, Hanford, Kerman, Kingsburg, Lemoor, Parlier, Reedley, Sanger, and Selma.

In April 2007, KRCD began to solicit proposals for up to 400 MW of eligible renewable energy supplies for the Authority.[27] The Authority has retained KRCD as its exclusive operating agent for the CCA program. In January 2007 the Authority filed its implementation plan for CCA with the CPUC. The Authority plans to begin serving customers in November 2007. A copy of the Authority's implementation plan is available on the Authority's website.[28]

South San Joaquin Irrigation District

The South San Joaquin Irrigation District (SSJID) hopes to begin service as a new LSE perhaps as soon as early 2008. SSJID plans to serve loads in the cities of Manteca, Ripon, and Escalon for a total of about 38,000 end-use customers. Annual peak load in 2008 is estimated to be about 138 MW.

SSJID was founded in 1909 to provide irrigation water to agricultural areas. Presently it provides this service for about 72,000 acres, mostly for almond farms. In June 2005, the SSJID Board voted unanimously to proceed with the attempt to purchase PG&E's distribution network and provide electric service to Manteca, Ripon, and Escalon. SSJID's plan of service and its offer to PG&E are posted on its website.[29] The district plans to contract for scheduling, shaping, and ancillary services, and plans to contract with MID for continuing certain public benefit programs such as energy efficiency and renewable investments. PG&E and MID presently compete for retail customers in the southern part of SSJID's prospective service territory. This competition between PG&E and MID has led to some duplication of distribution facilities.

The district has a 50 percent interest in the Tri-Dam Project on the Stanislaus River. Hydroelectric generation from this project was sold to PG&E under a 50-year contract that expired at the end of 2004. Sales have continued under a five-year power sales agreement. During forecast summer peak periods, those hydro resources are likely to provide 120 MW in dependable capacity (with about 60 MW being available to SSJID). Since some of these hydro resources may have a higher value in the marketplace as dispatchable resources, SSJID will likely consider supplementing or replacing these supplies by purchasing a shaped portfolio of resources.

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[27] See [http://www.lemoore.com/graphics/pdf/sjvpa_renewable_rfp_final.pdf].
[28] See [www.communitychoice.info].
[29] See [http://www.ssjid.com/serv-electricity.htm].

No-Load LSEs (Entities Not Serving Any Electrical Loads)

During the compilation of information for this report, three publicly owned entities were found who in previous years had taken initial steps for authorization to procure electricity and serve retail end-use customers. However, these three entities have subsequently not taken on the obligation to serve retail load for various reasons. Without the obligation to serve, these entities currently have no obligation to either plan or procure electricity to be resource adequate.

City of Chula Vista

During the energy crisis of 2000-2001, the city of Chula Vista (Chula Vista) in San Diego County witnessed several companies leave the area, blaming high electricity prices. In 2000, Chula Vista declared itself a POU by ordinance and at one time envisioned an annual peak load of 225 MW.

In 2004, the city of Chula Vista signed an agreement with SDG&E that it would not enter the transmission or distribution business (as a POU) until after 2014, at the earliest. For a 10-year period, Chula Vista will not compete with SDG&E for bundled customers. Chula Vista retains the right to become a community choice aggregator to supply departing SDG&E loads but does not presently serve any load and has no plans of doing so in the near future.

Since this 2004 agreement, SDG&E has also agreed to support undergrounding of one transmission line near the South Bay Power Plant, which addressed an important community concern.

Monterey County Water Resources Agency

The Monterey County Water Resources Agency (Monterey County) is authorized to plan, build, develop, and operate hydroelectric generation and does so at the Nacimiento Reservoir in southern Monterey County near the headwaters of the Salinas River.

The agency is also authorized by the Monterey County Water Resources County Agency Act (Chapter 52, Section 9), to "provide, generate, sell, and deliver hydroelectric power … to any public agency, public utility, private corporation, or other person or public entity, or any combination thereof, engaged in the sale of electric power."[30]

The output from Nacimiento is RPS-eligible[31] energy that has in the past been sold to PG&E. Monterey County has never sold hydroelectric energy to an individual end-user and has no plans to become a load-serving entity. It is expected that Monterey

[30] See [http://www.mcwra.co.monterey.ca.us/Mission_Vision/Agency%20Act.pdf]
[31] Renewables Portfolio Standard.

County will continue to offer the output of Nacimiento to an IOU or ESP needing this supply to meet its state-mandated RPS goals.

City of Santa Maria

The city of Santa Maria, through its public works department, took initial steps in 2004-2005 to become an LSE. It considered becoming a publicly owned electric utility to serve undeveloped land east of U.S. Highway 101 that would be annexed to the city. During this period, Santa Maria studied the advantages of constructing its own underground distribution system.

At this time, the city of Santa Maria is no longer seeking to become an electricity LSE and can therefore be considered a no-load LSE for the foreseeable future. The city is pursuing a cogeneration project at its wastewater treatment plant. This project would use digester gas for the electric load for sewage treatment, and the electricity would be neither sold nor delivered to other end-users. This self-generation would reduce electricity consumption that would otherwise be delivered by PG&E. The city has investigated the potential value of energy from this wastewater cogeneration project as a source of revenue from the sale of renewable energy credits (RECs).

CHAPTER 7: Further Questions and Unresolved Policy Issues

In this initial examination of resource adequacy, the Energy Commission has developed an improved understanding of the complexities related to resource adequacy resident in the 54 POUs that exist today. This report does not attempt to define resource adequacy for all of these entities in a uniform manner, nor does it define a uniform standard by which the resource adequacy protocols of each LSE might be judged. Nonetheless, several questions are outstanding that should be the focus of further examination and policy discussion. This chapter identifies such topics and offers some proposals on how these uncertainties and controversies might best be examined and addressed.

Common Requirements for All POUs

The CPUC has attempted to implement resource adequacy in a manner that is largely identical for many of the LSEs under its jurisdiction, even though these range in size from 4 MW to 22,889 MW of peak demand in 2006. At present, there are exceptions carved out for or unresolved issues related to obligations for selected LSEs. As noted in Chapter 3, with one micro-utility (Mountain Utilities), one small utility (Bear Valley Electric), and two multi-jurisdictional IOUs (Sierra Pacific Resources and PacifiCorp) under its jurisdiction, the CPUC has yet to fully resolve the implications of the diversity of LSE circumstances for resource adequacy regulation, much less to do so with a uniform set of requirements.

The diversity of responsibilities to provide electrical services to loads and other circumstances among POU LSEs (both inside and outside the California ISO control area) may make equal treatment either inappropriate or difficult to implement. Chapters 4 and 5 illustrate the marked diversity among POUs referenced above. Five small POUs are in control areas that are primarily located in other states and have balancing authorities that operate in multiple jurisdictions and provide integrated resource plans to other public utilities commissions. Many POUs have existing agreements with the balancing authorities in their control areas that provide incentives to be resource adequate, or to transfer at least a share of the risks associated with resource inadequacy to the latter. In at least one instance, resident POUs bear the entire risk of inadequacy since the control area operator (LADWP) can curtail load for individual LSEs. In another, curtailment risk in a control area is borne entirely by customers of a single LSE (IID), as the utility service area and control area are both coterminous and coincident. Any proposed set of resource adequacy requirements to be applied uniformly to the state's 54 POUs will, at the very least, have to consider not only the diversity of POUs in its numerous aspects, but also of the control areas in which they reside and the relationships between LSEs and their respective control area balancing authorities.

Chapter 3 provides insight into the potential complexity of a resource adequacy determination. On the demand-side, the forecast used to assess resource adequacy must be established; this can differ for system-wide and local resource adequacy evaluation (as is the case for LSEs in the California ISO control area). Procedures to independently evaluate the forecast and translate non-coincident forecasts into coincident forecasts may be necessary. Most significantly, the (one) PRM that each POU would be required to maintain needs to be determined. Given that the relationship between a PRM and levels of reliability is difficult to estimate (and will vary depending upon the specific resource portfolio procured by the LSE), the selection of a specific value will yield various levels of reliability, none of which would necessarily reflect the risk preferences of LSE customers.

The rules for determining the qualifying capacity of each type of resource, including demand-side and contractual resources, must be established, as well as how limited-availability resources can best be aggregated in a portfolio. Existing counting conventions vary across LSEs; many differ from those established for CPUC-jurisdictional entities. Many POUs have long-term contracts with quasi-public entities that own and control large generation portfolios (for example, Western and BPA). While both parties would argue that these contracts are a reliable source of capacity, it is not clear that they would yield qualifying capacity under criteria for CPUC-jurisdictional entities. POUs also have contracts with other POUs that do not specify the specific generation resource in the seller's portfolio that would provide the electricity. Some POUs are phasing out non-unit specific liquidated damages (LD) contracts on a schedule similar to that required by CPUC decisions affecting IOU and ESP procurement. Other POUs believe that LD contracts have been valuable and reliable resources, more so in some cases than in unit-specific contracts with *force majeure* allowances for non-delivery. [32]

Still other POUs have modified the pro forma agreement for an LD product to a contract requiring a specific portfolio to back a firm energy delivery obligation. These contracts may be used more frequently as utilities seek to identify and reduce liabilities relating to greenhouse gas emissions. In summary, any set of rules relating to qualifying capacity requires an assessment of the types of contracts that would provide qualifying capacity, as well as the circumstances under which they would do so.[33]

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[32] PG&E recommended in this proceeding and elsewhere that publicly owned LSEs should not be allowed to count LD contracts toward resource adequacy obligations. FERC decided, on September 21, 2007, not to rule out LD contracts for this purpose, stating "We decline to establish a cut-off date beyond which liquidated damage contracts can no longer be used for resource adequacy purposes, as PG&E suggests. While we agree that these contracts fail to ensure availability of deliverable capacity, we find that this matter is more appropriately addressed by Local Regulatory Authorities. We also note that the CAISO states that it will work with LSEs to phase out liquidated damages contracts that are included in resource adequacy portfolios." (Ordering paragraph 1284)

[33] Even whether a resource is contracted with or is utility-owned may not be clear in the case of some resources held by JPAs and contracted for by parties to those very same entities.

The required PRM and timeline for procurement must be laid out; even the month- and year-ahead requirements set forth for CPUC-jurisdictional entities may discourage the timely development of new capacity and require future revision (see below).

Currently, LSEs not under CPUC jurisdiction adopt resource adequacy standards either of their own choosing or explicitly (or implicitly) imposed upon them by agreements with the balancing authority in their respective control areas. More information is needed for staff to fully understand the relationships between balancing authorities and their constituent publicly owned LSEs (see the next section); but it is perhaps significant that no entity has indicated that this relationship was problematic for them in terms of reliability and resource adequacy. Nor would it appear that the diversity of standards within any control area has an impact on reliability in other control areas. They do not affect the latter's ability to meet operational reliability criteria established by NERC, or the ability of LSEs in the latter control area to procure the amount of capacity dictated by resource adequacy requirements within the required timeframes.

Responsibilities of Control Area Operators

As noted in Chapter 2, some POUs serve as both LSE and balancing authority of a control area. Significantly, AB 380 does not explicitly consider the control area and any planning responsibilities it might have that are separate from the POU as an LSE. The primary function of such entities is to manage the grid in real time to satisfy reliability standards. The four control areas in California operated by POUs are SMUD/Western, Turlock, LADWP, and IID. Of these, only the IID control area is conterminous with its own utility service area. The other three control areas encompass the loads and resources of other POUs. The SMUD/Western control area, especially the Western sub-control area with its four POUs (Modesto, Roseville, Redding, and Shasta Lake), along with numerous end-users served directly by Western, is especially complex.

The filings submitted by POUs included some information about activities by selected entities in their capacities as control area operators, but more information is needed to fully understand the activities of individual public utility control area operators that relate to resource adequacy. For example, LADWP reported that "[under] its interconnection agreements with Burbank and Glendale, [it] verifies with each POU in its control area the resources providing the necessary reserve requirement in regards to each POU's respective Most Single Severe Contingency. Verification includes the task of establishing and monitoring Burbank's and Glendale's shares of this requirement, based on their coincident Most Severe Single Contingency." SMUD reported that its role as a control area operator is to provide real-time balancing authority services through a contract with WAPA and its sub-control area member LSEs. SMUD does not perform the function of planning authority for Western or member LSEs. As a control area operator, SMUD's System Operations & Reliability Group supervises control area reliability daily with the cooperation of other control area entities. These entities perform their own reliability studies and coordinate operations with SMUD in real time to meet NERC and WECC planning and operation requirements.

- What do control area operators do when they find themselves short of resources due, for example, to higher-than-expected loads or the failure of a large generation unit?
- What are the expectations placed on control area operators for backstop procurement for daily operations (or under emergency conditions), and how are these met?
- What responsibility for resource adequacy does and should a control area operator bear?

For the California ISO, these questions address one of its major functions and consume much of its attention.

- Should and do other control area operators place requirements on other participating POUs to ensure that they are adequate or, if not, what are the consequences?
- Do the control areas operated by POUs ever acquire and commit resources in day-ahead markets to meet the balancing needs related to system load and reserve requirements?
- What roles do control areas assume as reliability concerns move from month-ahead scheduling to the real-time responsibilities of commitment and dispatch?

These questions are appropriate for further study.

Local Capacity Requirements

In future years, POUs within the California ISO control area may be subject to requirements for local capacity procurement. The California ISO has defined numerous local reliability areas (LRAs) and sub-areas in which aggregate procurement by LSEs must meet a threshold local capacity requirement (LCR). This requirement follows from the need for on-demand generation within transmission-constrained areas to meet (operational) reliability standards, should transmission into or generation within the area be impaired by the sudden failure of a system component.[34]

[34] This generation has historically been procured by the California ISO in the form of reliability must-run (RMR) contracts.

How do other control area operators and their resident LSEs evaluate the need for local capacity? What level of local capacity is needed, if any, in these control areas and how is the responsibility for procuring this capacity allocated or assigned?

Interaction Between Generation and Transmission

Given the nature of publicly owned LSEs, most of which serve customers in a specific, confined service area, which is effectively an island within a larger entity's transmission service area, and what are the opportunities for such a POU to acquire resources to satisfy resource adequacy? PG&E in its transmission planning role and in its load-serving role has certain opportunities to trade-off generation versus transmission options to deal with resource adequacy requirements, particularly local capacity requirements. Most POUs do not own or control transmission and thus do not have such transmission options for meeting their reliability needs. It is unclear whether many smaller POUs have the expertise to even participate in transmission planning activities, let alone engage in complex tradeoffs between transmission additions, upgrades, and resource additions.

How can POUs fairly participate in transmission versus resource addition comparative studies?

Time Horizon for Assessment Studies

As noted in Chapter 2, CPUC Section 380 specifically identifies generation development as one of the objectives that resource adequacy is intended to address. The CPUC has created its resource adequacy program predicated upon a one-year-ahead procurement requirement. It is scheduled to examine the question of multi-year forward variants of resource adequacy in R.05-12-013, Phase 2, Track 2.

The information reporting requirements established by the Energy Commission extend only one year forward, mirroring those established by the CPUC. Should POUs be encouraged to think of resource adequacy as encompassing investment time horizons? Should the Energy Commission be asking POUs to provide information about loads, resources, and procurement strategies three to five years into the future?

APPENDIX A: Peak Loads in 2006

Table A-1: Annual Non-Coincident Peak Loads of California POUs

2006 Peak MW [1]	Publicly Owned Load-Serving Entities (LSEs)	Control Area	Sub-total class MW / Share	POU Type
11,477.0	**Large LSEs (over 1,000 MW)**		60.66%	
6,165.0	Los Angeles Department of Water and Power (LADWP)	LADWP		City
3,280.0	Sacramento Municipal Utility District (SMUD)	SMUD		MUD
2,032.0	DWR: State Water Project	CAISO		State
6,470.0	**Mid-Sized LSEs (200 MW to 1,000 MW)**		34.19%	
993.0	Imperial Irrigation District (IID)	IID		ID
686.7	Modesto Irrigation District (MID)	CAISO		ID
593.0	Anaheim, City of	CAISO		City
587.0	Riverside, City of	CAISO		City
533.0	Turlock Irrigation District (TID)	Turlock		ID
526.7	Northern California Power Agency — power pool [1]	CAISO		see note
393.0	Western's end-use customer loads [2]	CAISO		Federal
107.0		SMUD		
486.0	Silicon Valley Power (City of Santa Clara)	CAISO		City
352.0	Roseville Electric	SMUD		City
336.0	Glendale Water & Power	LADWP		City
316.6	Pasadena Water & Power	CAISO		City
307.0	Burbank Water & Power	LADWP		City
253.0	Redding Electric Utility	SMUD		City
669.2	**Compact LSEs (50 MW to 200 MW)**		3.54%	
197.3	Vernon, City of	CAISO		City
120.0	CCSF (City and County of San Francisco)	CAISO		City
120.0	Power and Water Resources Pooling Authority (PWRPA)	CAISO		JPA
87.0	Colton, City of	CAISO		City
81.6	Merced Irrigation District	Turlock		ID
63.3	Azusa Light & Water	CAISO		City
264.7	**Sub-Compact LSEs (10 MW to 50 MW)**		1.40%	
45.0	Banning, City of	CAISO		City
33.6	Shasta Lake, City of	CAISO		City
31.2	Truckee Donner Public Utility District	SPP		PUD
25.8	Lassen Municipal Utility District	CAISO		MUD
25.0	Surprise Valley Electric Cooperative	BPA		Coop
19.0	Needles, City of	Nevada		City
18.0	Trinity Public Utility District	CAISO		PUD
15.7	Moreno Valley Utilities	CAISO		City
14.0	Corona, City of [3]	CAISO		City
13.0	Eastside Power Authority	CAISO		JPA

2006 Peak MW [1]	Publicly Owned Load-Serving Entities (LSEs)	Control Area	Sub-total class MW / Share	POU Type
12.5	Anza Electric Cooperative, Inc.	CAISO		Coop
12.0	Rancho Cucamonga Municipal Utility	CAISO		City
40.0	**Mini-Compact LSEs (less than 10 MW)**		0.21%	
10.0	Cerritos, City of (a "Community Aggregator")	CAISO		CA
6.0	Industry, City of	CAISO		City
5.3	Morongo Band of Mission Indians	none		Tribal
4.5	Pittsburg, City of / Island Energy	CAISO		City
3.6	Victorville Municipal	none		City
2.9	Valley Electric Association [4]	Nevada		Coop
2.8	Port of Stockton	CAISO		MUD
2.7	Hercules Municipal Utility	CAISO		City
1.5	Aha Macav Power Service (Fort Mojave Tribe) [4]	WALC		Tribal
0.7	Shelter Cove Resort Improvement District	CAISO		RID
0.0	McAllister Ranch Irrigation District [5]	CAISO		ID
18,921.0	Total 2006 POU *Non*-Coincident Peak Loads		100.00%	

Source: California Energy Commission, Electricity Analysis Office, September 2007.

[1] There are 10 small public LSEs in the NCPA Power Pool: 8 cities, 1 MUD, and 1 Coop. All are in CAISO, and NCPA schedules resources to serve the aggregate load. Their *non*-coincident peak loads in 2006 were: Palo Alto 190.3 MW, Lodi 140.4 MW, Alameda 70.2 MW, Ukiah 36.0 MW, Plumas-Sierra 30.5 MW, Lompoc 26.3, Healdsburg 21.1, Port of Oakland 12.4 MW, Gridley 10.4 MW, and Biggs 4.0 MW.
[2] Western's end-use loads do not include sales to customers such as Trinity PUD that are defined as an LSE by the Energy Commission. This number is an Energy Commission estimate.
[3] Does not include Corona's ESP annual peak load, also about 14 MW.
[4] Only estimates of non-coincident peak California loads are shown for multi-state LSEs.
[5] McAllister Ranch ID began service on Feb. 5, 2007.

Table A-2: Annual Non-Coincident Peak Loads of All California LSEs

2006 Peak MW [1]	Investor-Owned Utilities and Publicly Owned Load-Serving Entities (LSEs) in California	Control Area	Non-POU Type
42,267.0	**Jumbo LSEs (over 10,000 MW)**		
22,889.0	Southern California Edison Co.	CAISO	IOU
19,378.0	Pacific Gas & Electric Co.	CAISO	IOU
15,979.0	**Large LSEs (1,000 to 10,000 MW)**		
6,165.0	Los Angeles Department of Water and Power (LADWP)	LADWP	
4,502.0	San Diego Gas & Electric Co.	CAISO	IOU
3,280.0	Sacramento Municipal Utility District (SMUD)	SMUD	
2,032.0	DWR: State Water Project	CAISO	
6,470.0	**Mid-Sized LSEs (200 to 1,000 MW)**		
993.0	Imperial Irrigation District (IID)	IID	
686.7	Modesto Irrigation District (MID)	CAISO	
593.0	Anaheim, City of	CAISO	
587.0	Riverside, City of	CAISO	
533.0	Turlock Irrigation District (TID)	TID	
526.7	Northern California Power Agency power pool [1]	CAISO	
393.0	Western's end-use customer loads [2]	CAISO	
107.0		SMUD	
486.0	Silicon Valley Power (SVP)	CAISO	
352.0	Roseville Electric	SMUD	
336.0	Glendale Water & Power	LADWP	
316.6	Pasadena Water & Power	CAISO	
307.0	Burbank Water & Power	LADWP	
253.0	Redding Electric Utility	SMUD	
974.2	**Compact LSEs (50 to 200 MW)**		
197.3	Vernon, City of	CAISO	
180.0	PacifiCorp [3]	PacifiCorp	IOU
125.0	Sierra Pacific Power Co. (SPP) [3]	SPP	IOU
120.0	CCSF (City & County of San Francisco)	CAISO	
120.0	Power & Water Resources Pooling Authority (PWRPA)	CAISO	
87.0	Colton, City of	CAISO	
81.6	Merced Irrigation District	TID	
63.3	Azusa Light & Water	CAISO	
305.7	**Sub-Compact LSEs (10 to 50 MW)**		
45.0	Banning, City of	CAISO	
41.0	Bear Valley Electric Service	CAISO	IOU
33.6	Shasta Lake, City of	CAISO	
31.2	Truckee Donner Public Utility District	SPP	

2006 Peak MW [1]	Investor-Owned Utilities and Publicly Owned Load-Serving Entities (LSEs) in California	Control Area	Non-POU Type
25.8	Lassen Municipal Utility District	CAISO	
25.0	Surprise Valley Electric Cooperative	BPA	
19.0	Needles, City of	Nevada	
18.0	Trinity Public Utility District	CAISO	
15.7	Moreno Valley Utilities	CAISO	
14.0	Corona, City of	CAISO	
13.0	Eastside Power Authority	CAISO	
12.5	Anza Electric Cooperative, Inc.	CAISO	
12.0	Rancho Cucamonga Municipal Utility	CAISO	
43.8	**Mini-Compact LSEs (less than 10 MW)**		
10.0	Cerritos, City of (a "Community Aggregator")	CAISO	
6.0	Industry, City of	CAISO	
5.3	Morongo Band of Mission Indians	none	
4.5	Pittsburg, City of / Island Energy	CAISO	
3.8	Mountain Utilities	none	IOU
3.6	Victorville Municipal	none	
2.9	Valley Electric Association [3]	Nevada	
2.8	Port of Stockton	CAISO	
2.7	Hercules Municipal Utility	CAISO	
1.5	Aha Macav Power Service (Fort Mojave Tribe) [3]	WALC	
0.7	Shelter Cove Resort Improvement District	CAISO	
0.0	McAllister Ranch Irrigation District [4]	CAISO	
66,039.8	Total 2006 IOU + POU *Non*-Coincident Peak Loads		
1,820.0	Estimated Sum of *Non*-Coincident Peak Loads for 14 Energy Service Providers (ESPs) [6]	CAISO	ESPs
67,859.8	Statewide Total of All LSE *Non*-Coincident Peak Loads in 2006		

Source: California Energy Commission, Electricity Analysis Office, September 2007

[1] There are 10 small public LSEs in the NCPA Power Pool: 8 cities, 1 MUD, and 1 Coop. All are in the California ISO balancing authority area, and NCPA schedules resources to serve the aggregate load. Their *non*-coincident peak loads in 2006 were: Palo Alto 190.3 MW, Lodi 140.4 MW, Alameda 70.2 MW, Ukiah 36.0 MW, Plumas-Sierra 30.5 MW, Lompoc 26.3, Healdsburg 21.1, Port of Oakland 12.4 MW, Gridley 10.4 MW, and Biggs 4.0 MW.
[2] Western's end-use loads do not include sales to customers such as Trinity PUD that are defined as an LSE by the Energy Commission. This number is an estimate by CEC staff.
[3] Only estimates of non-coincident peak California loads are shown for multi-state LSEs.
[4] McAllister Ranch ID began service on Feb. 5, 2007.
[5] The actual non-coincident peak loads for ESPs in 2006 is confidential, even if aggregated. Five ESPs had peak loads in 2006 greater than 200 MW: APS Energy Services, Constellation NewEnergy, Pilot Power, Sempra Energy Solutions, and Strategic Energy. Estimate is by Electricity Analysis Office using LSE resource plans and public data.

Table A-3: Non-Coincident Peak Load Shares in California by LSE Size

LSE Size Class	Total MW	Share	# LSEs
Jumbo LSEs (over 10,000 MW)	42,267	64.00%	2
Large LSEs (1,000 to 10,000 MW)	15,979	24.20%	4
Mid-Sized LSEs (200 to 1,000 MW) [1]	6,470	9.80%	14
Compact LSEs (50 to 200 MW)	974	1.48%	8
Sub-Compact LSEs (10 to 50 MW)	306	0.46%	13
Mini-Compact LSEs (less than 10 MW)	44	0.07%	12
Totals [2]	**66,040**	**100.00%**	**53**

Source: California Energy Commission, Electricity Analysis Office, September 2007

[1] NCPA is counted once in this class since loads and resources of the 10 LSEs in the NCPA Power Pool are scheduled and dispatched like a single LSE.
[2] This table does not include about 1,820 MW served by 14 ESPs.

Table A-4: Peak Loads by LSE Types and Control Areas

Sum: All LSE 2006 Loads in MW	IOU 2006 Loads in MW	POU 2006 Loads in MW	ESP 2006 Loads in MW	Balancing Authority Area (Control Area)	# IOUs	# POUs	# ESPs	# All LSEs
				Entirely (or almost entirely) within California				
54,334	46,810	5,704	1,820	California Independent System Operator	4	36	14	54
6,808		6,808		LADWP		3		3
4,712		4,712		SMUD / Western		6		6
993		993		Imperial Irrigation District (IID)		1		1
615		615		Turlock Irrigation District (TID)		2		2
				Partly in California, and based in adjacent states				
180	180			PacifiCorp	1			1
156	125	31		Sierra Pacific Power Co. (SPP)	1	1		2
25		25		Bonneville Power Administration (BPA)		1		1
22		22		Nevada Power Co.		2		2
2		2		Western Area Lower Colorado (WALC)		1		1
13	4	9		**Not Connected to the Grid**	1	2		3
67,860	**47,119**	**18,921**	**1,820**	**Statewide Totals [1]**	**7**	**55**	**14**	**76**
100.0%	69.4%	27.9%	2.7%	**Share of statewide totals by LSE Type**	9.2%	72.4%	18.4%	100.0%

Source: California Energy Commission, Electricity Analysis Office, September 2007

[1] Western is counted twice on this list as a POU as it serves end-use loads in 2 control areas.

APPENDIX B: Selected Resource Adequacy Narratives

Appendix B-1: Los Angeles Department of Water and Power

Rev 8, 2-13-07

Narrative descriptions regarding LADWP's resource adequacy obligations and standards

(A) Terms of existing tariffs and agreements that identify the specific nature of resource adequacy requirements that an LSE must satisfy.

As a separate control area, LADWP does not have the same resource adequacy requirement obligations as those of LSEs that are members of the CAISO. In April 2006, LADWP became party to the Western Electricity Coordinating Council (WECC) Reliability Management System (RMS) Agreement and Reliability Criteria (RMS Criteria) Agreement. Under the terms of these agreements, LADWP is required to, among other things, comply with the reliability criteria requirements of the WECC Reliability Criteria Agreement, as outlined in the May 1, 2005, WECC RMS Criteria Agreement and pay the WECC for any monetary sanction assessed against LADWP for non-compliance with the reliability criteria as a transmission operator. Compliance with subsequent amendments is currently pending approval of those amendments. Section 4.0 of the RMS Criteria Agreement outlines the specific obligations of LADWP to comply with the reliability criteria. A complete copy of the RMS Criteria Agreement and associated amendments can be viewed at the WECC website:
http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=viewdownload&cid=11

(B) Planning reserve margins for capacity or energy, and any other elements of standardized evaluations that address the balance between forecasted loads and available resources.

As a means of ensuring power system reliability, LADWP maintains an extra reserve margin of power generation resources in the event of a power system disturbance. In order to determine how much extra generation reserves are needed, LADWP adheres to the Western Electricity Coordinating Council (WECC) Reserve Standard, which is defined as follows:

Generation Capacity Requirement = Net Power Demand + System Reserve Requirement
System Reserve Requirement = Operating Reserve + Replacement Reserve
Operating Reserve = Contingency Reserve + Regulation

The "net power demand" is the total electrical power requirement for all of LADWP's customers at any time. The other reserve requirements are defined below, as well as numerically calculated.

Loss of the largest single contingency of generation or transmission (the Most Severe Single Contingency, or MSSC) is a key reserve margin determinant for LADWP and defines both the Contingency Reserve and Replacement Reserve requirements. LADWP uses WECC's loss of the largest single contingency rule instead of the 7 percent of load rule. LADWP's system load would have to exceed 8000 MW before WECC's "7 percent of load" criteria eclipses this "largest single contingency" criterion, and LADWP's load is not anticipated to exceed 8000 MW for at least 30 years. Under the current WECC Minimum Operating Reliability Criteria (MORC), at least 50 percent of the contingency reserves must be spinning reserve. In most cases in 2007, LADWP's MSSC used for contingency reserve is the loss of Haynes Units 8 – 10 (a combined-cycle genset). The replacement reserve requirement is to restore operating reserves within 60 minutes of a contingency event, typically the second MSSC when the first MSSC is unavailable. It is anticipated that for most cases in 2007, the loss of one Intermountain Power Project unit is LADWP's second MSSC (Replacement Reserve). At peak load conditions, the regulation requirement is comparatively small (25 MW) and is related to system load variations due to customer load changes. Given LADWP's total entitlement and all system resources available in 2007, the system reserve requirements would be calculated as follows:

Regulation = 25 MW
Contingency Reserve = 560 MW
Operating Reserve = 585 MW
Replacement Reserve= 521 MW
System Reserve Requirement = 1106 MW

In future years, as other system resources come on-line, LADWP's operating reserve and replacement reserve requirements will change depending on the MSSC and second MSSC available.

(C) Operating reserve requirements established by the Western Electricity Coordinating Council, control areas, and other authorities as they affect and determine resource adequacy obligations.

LADWP adheres to the WECC MORC requirements. See response to the previous question.

The LADWP control area consists of three POUs (LADWP, cities of Burbank and Glendale). As the control area operator, LADWP ensures that the system reserve requirement for the control area as a whole is addressed at all times. Under its interconnection agreements with Burbank and Glendale, LADWP verifies with each POU in its control area the resources providing the necessary reserve requirement for each POU's respective MSSC. This verification includes the task of establishing and monitoring Burbank's and Glendale's shares of this requirement, based on their respective coincident MSSCs.

There are no externally imposed resource requirements on LADWP.

(D) Any unit commitment and dispatch obligations imposed by control area operators or other entities operating interconnected electric transmission systems, and a description of how the LSE meets these obligations with generation it owns or controls;

LADWP, as a control area operator, has established its own reliability must-run (RMR) requirements that determine which of its generating units that must be synchronized and what, if any, minimum loading is necessary daily for system security and resource adequacy. Various factors that LADWP uses establishing its RMR requirement are:

- System stability
- Internal high voltage network connectivity
- Flow restrictions to meet network load in all parts of LADWP's service territory
- Voltage conditions internal to the LADWP control area
- Outages and construction on the LADWP grid
- Internal system loading

(E) Deliverability restrictions, dispatchability provisions, or transmission contingencies that affect the LSE's ability to rely upon specific resources, and a description of how these limitations might affect reliability of service.

Generation

- Castaic – Energy taken is limited due to the amount of the water resource, which is owned and scheduled by the California Department of Water Resources.
- Hoover – The Western Area Power Administration limits the amount of energy LADWP can take, via a monthly quota. Any generating capacity taken for LADWP's use is limited to what remains when the capacity associated with the energy is subtracted out of LADWP's allotment.
- Navajo – The amount of energy and capacity taken by LADWP is occasionally limited by transmission curtailments, including transmission controlled by other project participants.
- Palo Verde – It is not feasible to ramp down a nuclear power plant for other than forced outages or maintenance outages.
- Scattergood – Plant is occasionally derated and thus restricted in its ability to provide reserve capacity, due to the limitations on energy output from 230-kV and 138-kV underground cables connecting that generating station to the rest of the LADWP grid. With all three cables in service at their full ratings, the plant can operate at its maximum net output of about 800 MW; however, even a partial derating of 1 of these cables reduces the available generation from the plant.
    - Local Generator restrictions
    - Ramp rates
    - Mode limits (for example, combined cycle)
    - Time to synchronize
    - Dispatchability restrictions to meet hour deadline

- Small Combustion Turbines (47 MW) – can be used for replacement reserve, but not for spinning or non-spinning reserves, due to their time-to-synchronize.

Transmission/Control Area Operations

- Pacific DC (Northwest) – Bonneville Power Administration restricts LADWP from carrying spinning reserve on the line.
- IPP Southern Transmission System (STS) –LADWP's transmission capacity entitlement is barely sufficient to carry its generation capacity allocation from Intermountain Generating Station.
- LADWP transmission in the CAISO Control Area, and transmission related to COB. The 2 hour, 15 minute scheduling deadline limits LADWP's ability to call on the transmission to carry spin, non-spin reserves, and replacement reserves.
- Devers-Adelanto-Victorville (DAV) limitation (Southwest) – DAV to LADWP basin restriction on import of capacity and energy reserves. Sometimes this transmission corridor can become LADWP's single largest contingency when it becomes loaded heavily enough to exceed the MSCC described in the narrative response to issue (B).
- Southern California Import Transmission (SCIT) – Import restrictions similar to DAV to LADWP basin as noted above.

(F) The strategy that the LSE intends to pursue to achieve, and once accomplished maintain, the level of resource adequacy it has determined to be appropriate for its customers.

On a long-term basis, the strategy of LADWP is to provide sufficient generation to cover operating and replacement reserves in accordance with applicable WECC reliability requirements. LADWP tracks its load growth annually and checks to make sure it will have enough reserves over a 10 year planning horizon. If and when reserves are projected to be insufficient, LADWP will begin to investigate various alternatives to increase its energy or capacity reserves, such as build additional generation or procure energy through long-term contracts.

On a daily and real-time basis, the strategy of LADWP is not to leave itself short. This makes LADWP plan its generation to meet its load and not to fall below minimum reserve requirements.

Appendix B-2: City of Anaheim

The City Council for the City of Anaheim, California (Anaheim) hereby adopts the following Resource Adequacy Program for the Anaheim's Public Utilities Department (Department). Capitalized terms not otherwise defined herein shall be defined as set forth in the Master Definitions Supplement of the California Independent System Operator Corporation's (CAISO) Tariff as filed with the Federal Energy Regulatory Commission (FERC). This Resource Adequacy Program shall remain in effect, subject to modification by the City Council, until the implementation of the CAISO's Market Redesign and Technology Upgrade ("MRTU") Tariff.

1. RESOURCE ADEQUACY PLANS

The Department shall be responsible for developing Resource Adequacy Plans to guide the procurement of capacity resources adequate to serve the requirements of the Anaheim's customers consistent with Good Utility Practice and applicable reliability requirements. The Resource Adequacy Plans shall identify any Local Capacity Area Resources, as defined by the CAISO, included as capacity resources owned or contracted for by Anaheim for the period covered by each plan. The objective of the plan will be to achieve no less than a 12% reserve margin over monthly peak loads transitioning to a minimum 15% reserve margin by 2010.

1.1 Annual Resource Adequacy Plan: The Department shall prepare an Annual Resource Adequacy Plan each year for the following year. The Annual Resource Adequacy Plan shall identify capacity resources owned or contracted for by Anaheim sufficient to initially meet the greater of (i) 112% of Anaheim's forecast monthly peak loads for October through April and 100.8% of Anaheim's forecast monthly peak loads for May through September, or (ii) the most recent minimum planning reserve and reliability criteria approved by the Board of Trustees of the Western Electricity Coordinating Council. The Department shall provide the Annual Resource Adequacy Plan to the City Council by September 15 of each year and shall send the plan to the CAISO by September 30 of each year to the extent required by the CAISO Tariff.

1.2 Monthly Resource Adequacy Plan: The Department shall prepare a Monthly Resource Adequacy Plan by no later than the last business day of the second month prior to the month covered by the Plan (*e.g.*, by February 28 for the month of April). The Monthly Resource Adequacy Plan shall identify capacity resources owned or contracted for by Anaheim sufficient to initially meet the greater of (i) 112% of Anaheim's forecast maximum peak load for the month covered by the report or (ii) the most recent minimum planning reserve and reliability criteria approved by the Board of Trustees of the Western Electricity Coordinating Council. The Department shall provide each Monthly Resource Adequacy Plan to the City Council and to the CAISO to the extent required by the CAISO Tariff.

1.3 Monthly Energy Plan: The Department shall prepare a Monthly Energy Plan by no later than the last business day of the second month prior to the month covered by the Plan (e.g., by February 28 for the month of April). The Monthly Energy Plan shall plot in load duration curve format Anaheim's hourly demand forecast adjusted by the reserve margin; and in resource duration curve format Anaheim's capacity resources used to meet the resource adequacy requirements. The Department shall take into account the capacity resource limitations, e.g., energy limitations; run time limitations, and operational limitations of each resource in plotting the resource duration curve.

2. DEMAND FORECASTS

The Department shall be responsible for developing Demand Forecasts, consistent with Good Utility Practice, of the maximum annual and monthly peak loads for the Anaheim's Service Area on a schedule adequate for inclusion of such Demand Forecasts in the Annual and Monthly Resource Adequacy Plans. The Department shall provide the Demand Forecasts to the CAISO to the extent required by the CAISO Tariff.

3. CRITERIA FOR QUALIFYING CAPACITY

3.1 Thermal Facilities Owned by Anaheim Within Anaheim's Service Territory: The Qualifying Capacity of thermal generating facilities owned by Anaheim, in whole or in part, and located within Anaheim's Service Territory will be based on net dependable capacity defined by North American Reliability Council ("NERC") Generating Availability Data System ("GADS") information. If the facility is owned jointly with another entity, Anaheim will provide information in the Resource Adequacy Plans demonstrating Anaheim's entitlement to the output of the jointly-owned facility's Qualified Capacity and an explanation of how that entitlement may change if the facility's output is restricted.

3.2 Facilities Owned by Anaheim Within the CAISO Control Area: The Qualifying Capacity of thermal generating facilities owned by Anaheim, in whole or in part, and located within the CAISO Control Area but outside Anaheim's Service Territory will be based on net dependable capacity defined by North American Reliability Council ("NERC") Generating Availability Data System ("GADS") information. If the facility is jointly owned with another entity, Anaheim will provide information in the Resource Adequacy Plans demonstrating Anaheim's entitlement to the output of a jointly-owned facility's Qualified Capacity and an explanation of how that entitlement may change if the facility's output is restricted.

3.3 Dynamically Scheduled System Resources: The Qualifying Capacity of a Dynamically Scheduled System Resource to which Anaheim has an entitlement shall be the amount of Anaheim's capacity entitlement, subject to meeting the allocation criteria under Section 40.5.2.2 of the CAISO Tariff. To the extent Anaheim has transmission rights pursuant to an existing transmission contract or contracts, Converted Rights, or Firm Transmission Rights at the intertie over which such Dynamically Scheduled resource is received in an amount no less than the

Qualifying Capacity for such resource, then such Dynamically Scheduled Resource shall be deemed to have satisfied the deliverability test. However, eligibility as a Resource Adequacy resource is contingent upon Anaheim securing transmission through any intervening Control Areas for the resource entitlement that cannot be curtailed for economic reasons or bumped by higher priority transmission.

3.4 Non-Dynamically Scheduled System Resources: The Qualifying Capacity of a System Resource to which Anaheim has an entitlement that is not Dynamically Scheduled shall be the amount of Anaheim's capacity entitlement to such System resource. Non-Dynamically Scheduled Resources acquired by Anaheim after February 15, 2006 shall be subject to meeting the allocation criteria under Section 40.5.2.2 of the CAISO Tariff. To the extent Anaheim has transmission rights pursuant to an existing transmission contract or contracts, Converted Rights, or Firm Transmission Rights at the intertie over which such Non-Dynamically Scheduled resource is received in an amount no less than the Qualifying Capacity for such resource, then such Non-Dynamically Scheduled Resource shall be deemed to have satisfied the deliverability test. For any Non-Dynamically Scheduled System Resource, Anaheim shall use best efforts to secure or cause to be secured transmission through any intervening Control Areas for the resource entitlement that cannot be curtailed for economic reasons or bumped by higher priority transmission. System Resources that are not unit contingent must not be subject to curtailment for economic reasons. Any inter-temporal constraints, such as multi-hour run blocks, must be explicitly identified in Anaheim's monthly Resource Adequacy plan, and Anaheim will not impose constraints beyond those explicitly stated in the plan.

3.5 Contracts with Liquidated Damage Provisions: Firm energy contracts with liquidated damages provisions, as generally reflected in Service Schedule C of the Western Systems Power Pool Agreement or the Firm LD product of the Edison Electric Institute pro forma agreement, or any other similar firm energy contract that does not require the seller to source the energy from a particular unit, and specifies a delivery point internal to the CAISO Control Area shall be eligible to count as Qualifying Capacity until the end of 2010. Anaheim, however, will not have more than 75% of its portfolio of Qualifying Capacity met by contracts with liquidated damage provisions for 2006. This percentage will be reduced to 50% for 2007 and 25% for 2008–2010.

3.6 Operationally Limited Resources: The Qualifying Capacity for any operationally limited resources, e.g. energy limitations; run time limitations; or contract with a renewable resource as defined under the California Renewable Portfolio Standard ("RPS") is to be determined consistent with the Monthly Energy Plan described in Section 1.3 above.

3.7 Inter Scheduling Coordinator Trades: Contracts with specified generating resources within the CAISO Control Area delivered via an Inter Scheduling Coordinator Trade (SC to SC Trade) for administrative efficiency shall not be considered LD contracts and will count fully for the duration of the contract provided that (a) the resource is located within the CAISO Control Area and is deliverable pursuant to CAISO generation deliverability criteria; and (b) the SC to SC Trade is an administratively efficient means to schedule such energy to serve the Anaheim's load.

3.8 Exchange Contracts: The Qualifying Capacity for any exchange contract shall be the capacity that Anaheim is entitled to schedule under the exchange contract at the time of its forecast system peak. However, for an exchange contract, eligibility as a Resource Adequacy resource is contingent upon Anaheim securing transmission through any intervening Control Areas for the exchange capacity entitlement that cannot be curtailed for economic reasons or bumped by higher priority transmission and having met the allocation criteria for import capacity at the import Scheduling Point under Section 40.5.2.2 of the CAISO Tariff that is not less than the Resource Adequacy Capacity provided by the exchange contract.

3.9 Resource Adequacy Capacity Only Resources: Contracts for capacity only under which the seller has pledged to follow the CAISO's scheduling and operating protocols, including any Must Offer Obligation ("MOO") may be a source of Resource Adequacy Qualifying Capacity provided that the contract specifies: (i) the generating unit(s) dedicated for the Resource Adequacy Capacity, (ii) that the seller shall not sell the capacity covered by the contract to any third parties, and (iii) that the seller will follow CAISO operating instructions.

3.10 Load Reduction or Offset Programs: Energy efficiency, conservation, and demand response or demand offset programs may be a source of Resource Adequacy Capacity and shall be taken off the top of Anaheim's Resource Adequacy Capacity requirement. The Department shall document the effects of such demand reduction or offset programs in reducing Anaheim's demands in the Resource Adequacy Plans.

4. AVAILABILITY OF RESOURCE ADEQUACY RESOURCES TO THE CAISO

4.1 Availability During Normal Operating Conditions: Prior to the effective date of the CAISO's Market Redesign and Technology Upgrade Tariff, Anaheim shall utilize its Resource Adequacy Resources as necessary and appropriate to serve its loads. Anaheim may, but shall not be obligated to, submit a bid to sell capacity or energy from the Resource Adequacy Resource in the CAISO's markets.

4.2 Availability During System Emergencies: If the CAISO declares a System Emergency as provided for in CAISO Operating Procedure E508, Anaheim will comply with the terms of the Metered Subsystem Agreement with the CAISO and make available to the CAISO any available capacity from the Anaheim's Resource Adequacy Resources that is not required to serve Anaheim's loads. In the event Anaheim provides such capacity to the CAISO during a System Emergency, the terms and conditions for the sale of such capacity and associated energy shall be documented in a written communication affirmed by an authorized representative of the CAISO in the form attached as Appendix I.

5. ENFORCEMENT

The Department must report promptly to the City Council and the CAISO, to the extent required by the CAISO Tariff, any failure to comply with the requirements of this program. Such report must identify clearly the incident or incidents of non-compliance, describe in detail the actions the Department will take to re-establish full compliance with this program, and set forth a timeline for such actions.

Appendix B-3: Turlock Irrigation District

1 RESOURCE ADEQUACY

This is the Resource Adequacy Policy (Policy) of the Turlock Irrigation District (TID). The Policy requires preparation of a Demand Forecast and Supply Plan as specified below. The Policy also requires acquisition of resources to meet the Supply Plan, as specified below. The Policy focuses on capacity adequacy, complementing the energy adequacy requirements of the TID Risk Management Policies and Procedures. At such times that standards, practices, and requirements established by the Western Electricity Coordinating Council (WECC), the North American Electric Reliability Council (NERC), and applicable law and regulation are more stringent than this Policy, the more stringent practice will be followed.

1.1 Annual Demand Forecast

No later than June 1 of each year TID will establish a Demand Forecast for each of the months May through September of the following calendar year, based on median expected conditions. Demand shall be equal to TID retail sales plus firm wholesale sales plus any on-demand obligation to third parties, measured in MW or MWh/h for the hour of a month in which such computation is greatest. Demand reduction from Non-Dispatchable Demand resources will be factored into the Demand Forecast.

1.2 Monthly Demand Forecast

No later than the last business day of each month, TID will prepare or revise its Demand Forecast for the second following month.

1.3 Supply Plan

No later than June 1 of each year, TID will acquire sufficient capacity that together with Net Dependable Capacity (NDC) from TID's generators will meet 105% of its Demand Forecast reliably for each of the months May through September of the following calendar year. No later than the last business day of each month, TID will acquire sufficient capacity that together with NDC from TID's generators will meet 115% of its Demand Forecast reliably for the second following month. TID will at all times use best efforts to meet WECC Minimum Operating Reliability Criteria.

1.4 Resource Adequacy Plan Compliance

The Board of Directors of the Turlock Irrigation District hereby authorizes and directs staff as assigned by the General Manager to take such actions as are reasonably required to prepare its Demand Forecast and Supply Plan and comply with its Supply Plan.

1.5 TID System

The TID System means all transmission and distribution facilities and all Generating Units.

1.6 Dependable Capacity

Gross Maximum Capacity (“GMC”) is the maximum capacity a unit can sustain over a specified period of time when not restricted by deratings. Gross Dependable Capacity (“GDC”) is equal to GMC modified for seasonal limitations over a specified period of time. NDC is equal to GDC less the unit capacity utilized for that unit’s station service or auxiliaries.

1.7 Resource Adequacy Qualified Capacity

Resource Adequacy Qualified Capacity listed in either the annual or monthly Supply Plan shall be the NDC, as defined herein, of a resource, in MW as delivered to the TID System. The criteria for determining the types of resources that may be eligible to provide Qualified Capacity and for calculating Qualified Capacity from eligible resource types are provided in Section 1.8.

1.8 Qualified Capacity Criteria

1.8.1 Transmission

Eligibility as Qualified Capacity is contingent upon a) securing transmission through any intervening Control Areas for the resource entitlement that cannot be curtailed for economic reasons or b) anticipated availability for use of transmission with reliability not less than that of a generating unit.

1.8.2 Thermal

The Qualified Capacity of thermal facility will be its NDC.

1.8.3 Hydro

The Qualified Capacity of a pond or pumped storage hydro facility will be the NDC, with GDC based on current reservoir levels and snowpack and a 1-in-5 dry year forecast precipitation. The Qualified Capacity of a run-of-river hydro facility will be the NDC, with GDC based on actual or forecast flows and canal head.

1.8.4 Unit-Specific Contracts

On-peak contract amounts of unit-specific or utility-system-specific contracts will fully qualify as Qualified Capacity.

1.8.5 Firm Physical Contracts

Firm energy contracts a) which are based on an intention to achieve reliable physical delivery rather than frequent financial settlement for non-delivery, or b) which contain provisions that identify non-delivery as a default condition permitting contract termination, will fully qualify as Resource Adequacy Qualified Capacity, regardless of any provisions liquidating damages. As an example, Western Systems Power Pool Schedule C transactions are Qualified Capacity.

1.8.6 Wind and Solar

The Qualified Capacity of firm wind and solar generating facilities, with backup sources of generation, will be based on the NDC of the combined wind/solar and backup sources.

For wind and solar facilities without backup sources of generation, the Qualified Capacity for a month will be based on a forecast monthly capacity factor in the peak four-hour period applicable to days of that month, using anticipated median weather conditions. Data for not less than three years prior to the forecast will be used whenever available. Where less than three-years' data are available, historic data from another solar or wind generator located in the same weather regime with similar technology may be used.

1.8.7 Geothermal

The Qualified Capacity of a geothermal facility will be based on NDC, with GDC adjusted for steam field degradation.

1.8.8 Treatment of Qualified Capacity of QFs

The Qualified Capacity of a Qualified Facility (QF) having an obligation to meet load in the TID System, will be based on the type of resource as described elsewhere in Section 1.8.

1.8.9 Dispatchable Demand Resource

Dispatchable Demand resources available at least 8 hours in a month may be counted in the Supply Plan as Qualified Capacity for that month.

1.8.10 Facilities Under Construction

The Qualified Capacity for facilities under construction will be determined based on the type of resource as described elsewhere in Section 1.8. The facility will be Qualified Capacity in the annual or monthly Resource Adequacy Plan pursuant to the anticipated operational date of the facility.