CALIFORNIA AND WESTERN ELECTRICITY SUPPLY OUTLOOK REPORT APPENDICES A-E

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APPENDIX A: 2006 – 2008 CALIFORNIA ADDITIONS AND RETIREMENTS

CA ISO Control Area

SP26			NP26		
Additions			**Additions**		
Name	**MW**	**Expected By Summer**	**Name**	**MW**	**Expected By Summer**
Malburg	129	2006	Ripon	86	2006
Riverside ERC	85	2006	Walnut Energy Center	240	2006
Mountainview	1012	2006	San Francisco Peaker	40	2006
Palomar Escondido	480	2006		**366**	
	1706				
Otay Mesa	550	2008			
	550				
Retirements (High Risk)			**Retirements (High Risk)**		
Name	**MW**	**Date**	**Name**	**MW**	**Date**
Coolwater 1/2	-146	2005	Morro Bay 1/2 (Mothballed)	-326	2005
Mandalay 1/2	-433	2006	Pittsburg 7	-680	2006
Ormond	-1491	2006		**-1006**	
South Bay 4	-170	2006			
	-2240		Contra Costa 6	-336	2008
			Contra Costa 7	-336	2008
El Segundo	-670	2007	Morro Bay 3/4	-679	2008
Etiwanda 3/4	-640	2007	Pittsburg 5/6	-632	2008
	-1310			**-1983**	
Coolwater 3/4	-482	2008			
South Bay 1-3	-471	2008			
Encina 1-5	-947	2008			
	-1900				

Non-CA ISO Control Areas

LADWP & IID Control Areas			SMUD Control Area		
Additions			**Additions**		
Name	**MW**	**Expected By Summer**	**Name**	**MW**	**Expected By Summer**
Salton Sea #6 with Amendment	215	2008	Cosumnes	480	2006
El Centro 3 upgrades	37	2008		**480**	
Haynes 5 & 6 Repower	599	2008			
	851		Roseville Combined Cycle	153	2007
				153	

APPENDIX B: SUMMARIES OF LSE SUPPLY RESOURCE PLANS

Table B-1
Forecast Annual Peak Loads (MW) of Publicly Owned Utilities (POUs)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
LADWP	5,585	5,667	5,750	5,817	5,892	5,957	6,014	6,064	6,114	6,165	6,219
SMUD	3,005	3,064	3,125	3,184	3,246	3,308	3,371	3,431	3,492	3,550	3,598
Modesto	679	703	726	753	779	807	833	864	889	917	946
Anaheim	557	570	580	591	601	614	622	633	642	651	662
Riverside	539	544	550	555	561	572	584	595	606	618	630
Turlock	482	489	496	504	511	518	525	533	541	548	556
Silicon Valley	435	449	456	462	469	476	484	491	491	506	513
Roseville	337	353	372	390	405	418	423	426	430		
Pasadena	299	302	305	308	311	314	317	320	323	327	330
Glendale	286	290	294	298	303	308	312	316	320	324	328
Burbank	283	287	292	296	300	305	309	314	319	324	328
Redding	247	254	261	269	277	285	293	302	312	322	332
Totals	12,734	12,972	13,207	13,427	13,654	13,882	14,089	14,289	14,479	14,252	14,441

Source: California Energy Commission, LSE Resource Plan data

Publicly Owned Utilities

Los Angeles Department of Water & Power (LADWP)

Existing Resources

For each and every month beginning in January 2006 through May 2008, the Los Angeles Department of Water and Power (LADWP) has 5,425 MW of dependable capacity from fossil and nuclear resources. This total could decline slightly to 5,381 MW when repowering of Haynes begins and is then forecast to be 5,439 MW for the last four years of the forecast period through 2016.

About 63 percent of this capacity comes from four in-basin gas-fired plants: 803 MW Scattergood, 580 MW Valley, 463 MW Harbor, and 1,548 MW Haynes (using 2006 figures). LADWP also has dependable capacity and firm transmission from hydroelectric, nuclear, and coal-fired resources that are physically located in other states, but not designated as “imports.” These distant resources include Hoover

Dam (463 MW), Palo Verde (368 MW), Intermountain (1,186 MW), and Navajo (477 MW). LADWP has 10 percent ownership in Mojave, which will go offline by January 2006 and is it is assumed to stay off-line during the forecast period. Actual operation of Mojave may change as owners resolve pending issues or provide for alternative options.

The Castaic hydroelectric plant, on the West Branch of the California Aqueduct, provides 1,175 MW of valuable pumped-storage capacity. Modernization activities and storm damage may temporarily reduce this capacity to 872 MW while 10 MW of increased capacity is added to each of the six turbines. This modernization will add flexibility and energy efficiency to operations but is not expected to increase total plant generating capacity. LADWP delivers energy to CDWR in tandem with water deliveries through the system, equal to an average 45 MW.

During most years, LADWP can count on 166 MW from its series of large and small hydro plants located in the Owens Gorge, Owens Valley, and along the two aqueducts that deliver drinking water to the City of Los Angeles.

Because of its strong record on reliability first and low retail rates second, LADWP does not expect to lose customers to direct access retailers or community choice organizations.

LADWP was the only publicly owned utility to voluntarily provide numbers for three prominent if modest types of supply preferred resources. LADWP predicts slight adjustments to load from distributed generation (about 2 MW per year), and modest adjustments from future energy efficiency programs (from 9 to 18 MW per year). Dispatchable demand response counts for 30 MW throughout the forecast period.

LADWP does not have QF contracts or bilateral supply contracts, as defined by EIA. Also, although LADWP does have power purchase agreements with a few owners of cogeneration plants, it does not count on these facilities for any dependable capacity. Emerging technologies such as fuel cells and microturbines provide a modest amount of energy, but are not counted on for capacity during the forecast period.

Economy purchases represent an optional supply source for LADWP but are not counted as dependable capacity to serve forecast load. These purchases are often negotiated in the short-term or spot markets when it is economical for LADWP to do so. Many of these economy purchases can be delivered from out-of-state generating resources using LADWP's extensive transmission network, especially when output from its in-basin less efficient gas plants can be reduced to RMR levels. These economy purchases are limited mainly by the need to run in-basin plants certain minimum amounts in order to: provide local voltage support, maintain grid stability, and meet operating reserve requirements. For LADWP, these requirements are related to the largest single contingency (outage) in the supply portfolio. This single-largest contingency would be a forced outage or loss of transmission from the Intermountain coal plant (1,186 MW) near Delta, Utah.

Based on WECC reserve requirements and this contingency, LADWP is required to maintain around 1,100 MW of planning reserve margin, which is nearly a 20 percent planning reserve margin, significantly higher than the 15 percent to 17 percent margin that the CPUC has mandated for the IOUs.

Peak Demand

August is the peak demand month for LADWP. The net demand for retail customers is expected to rise from 5,585 MW in August 2006, to 6,219 MW in August 2016. For years 2010 through 2016, LADWP used proxy numbers for resources and loads. LADWP staff emphasize these proxy numbers have not yet been approved by LADWP governing authorities, but were provided to the Energy Commission using staff's best engineering judgement. The firm peak resource requirement includes a planning reserve margin of 1,100 MW, pursuant to WECC operating criteria and the average 45 MW obligation to CDWR.

Incremental Resource Needs

LADWP anticipates adding 60 MW of dependable capacity from generic (unnamed) renewable resources in 2010, plus another 60 MW in 2012, 2014 and 2016. Using existing and planned (named) resources, plus 240+ MW generic renewable resources and additional purchases of generic renewable resources, LADWP will have adequate electricity supplies to meet forecast load through 2016. This expectation of resource adequacy includes the 1,100 MW planning reserve margin and scheduled re-powering of Haynes and Scattergood.

Energy Requirements

August is the peak month for total energy demand. In 2006, the utility's total energy requirement, including economy sales, is pegged at 28,441 GWh. This amount increases to 31,727 GWh in 2016, representing an annual increase of about 1.1 percent.

Renewable Resources

LADWP has a strong preference for utility-owned and controlled resources, but may use contracted renewable energy supplies if they are necessary to achieve its RPS goals. LADWP expects to purchase about 250 GWh of renewable energy annually as part of its economy purchases. In the Tehachapi wind resource area, LADWP is developing Pine Tree Wind (120 MW nameplate), expected to be online in 2006 and producing 364 GWh annually. Significant biomass production is expected starting in 2008 (368 GWh per year). The Bradley landfill should contribute another 38 GWh each year.

Using the state-definition of eligible renewable resources, total amounts of renewable energy from both existing and planned resources and renewable energy purchases are forecast to grow from 1,075 GWh in 2006, to 4,639 GWh in 2016. These figures include generic renewable resource additions, which may grow from 278 GWh in 2006 to 3,420 GWh in 2016. Counting generic additions, renewable energy from utility-controlled resources and purchases will grow from 4 percent of total bundled customer load in 2006 to 15.2 percent in 2016.

For local reporting, energy from Hoover Dam (624 GWh) and Castaic Pumped Storage Facility (914 GWh) will not be counted towards meeting LADWP's renewable goals. However, LADWP will count as renewable all annual generation from Owens Gorge (228 GWh), Owens Valley (46 GWh), and aqueduct hydro plants (345 GWh). This is in accordance with recent Los Angeles City Council decisions which set ambitious RPS goals, and would not use the 30 MW nameplate distinction between state-defined eligible renewable resources and large hydro. By its own accounting, renewable energy will reach 13 percent in year 2010, and 19 percent by year 2016. These figures include generic renewable resource additions. LADWP will also count renewable energy from digester gas from the Hyperion sewage treatment plant, a fuel delivered for combustion with natural gas at nearby Scattergood.

Resource Planning Strategy and Goals

LADWP's approved "2000 Integrated Resource Plan" was designed to repower LADWP's 10 aging in-basin units while maintaining its paramount objectives: reliable service to customers, competitive price, and environmental leadership. At that time, LADWP set a goal meeting 50 percent of load growth (about 40 MW per year) with energy efficiency, renewable resources, and decentralized small-scale power sources. LADWP intends to remain a self-sufficient electricity supplier.

Uncertainties of Concern to LADWP

LADWP staff is currently preparing a new 10-year integrated resource plan. LADWP is the largest municipal electric utility in the nation, and serves about 10 percent of the load in California, while owning about 28 percent of high voltage transmission import capacity into California. Its electric service area is the City of Los Angeles, plus a small area in the Owens Valley. LADWP shares many of the concerns affecting a major LSE, an active market participant, an owner-operator of gas-fired and hydro generation, a responsible control area operator, and an owner of an extensive interstate transmission system. As a Department of city government, LADWP is ultimately responsible to publicly elected leadership, as well as to its rate-paying customers. LADWP is expected to provide funds for public benefit programs, such as low income energy assistance, and to transfer to the City's General Fund a certain percentage of the previous year's gross revenues. If net revenues from energy sales are less than expected, DWP is vulnerable to reductions in its long-term capital outlays and other controllable expenses. Proposed funding for the RPS goals will be made through a surcharge to customer rates, which is subject to Los Angeles City Council approval.

In its demand data filing with the Energy Commission, LADWP stated, "Population is probably the most significant variable in the forecast for the years 2010 and beyond" ("Retail Electric Sales and Demand Forecast" by City of Los Angeles Department of Water and Power, October 2004, page 5). While that demand driver is known, its weight is unknown. "The bottom line for LADWP is that there is no consensus on the population forecast, which adds uncertainty to the [demand] forecast." LADWP does not expect a large growth in peak summer demand. "A key assumption in the [demand] Forecast is that Peak Demand will grow at the same rate as NEL. This assumption implies a constant load factor over time. Over the past 10 years, the System Load Factor has been increasing. We attribute the increase in load factor to energy efficiency improvements, load shifting and the initial development of distributed generation."

Given the importance of its in-basin gas-fired generation, LADWP is concerned about current and forecasted prices of natural gas supplies. LADWP projects gas costs, has a natural gas financial hedging program, and now has a natural gas field in Southwestern Wyoming. LADWP regards the data as trade secrets, and the Energy Commission has granted confidentiality to this data about gas costs and hedging for three years.

Spot Market Supplies

DWP makes good use of short-term spot markets to save money, compared with the cost of DWP in-basin production. In August 2000, DWP saw routine reliance on short-term or wholesale markets as "an unacceptably risky situation for DWP and its customers" because this "wholesale market is one where energy is rationed by price and where the energy shortages can be created by market gaming rather than actual shortages."

Sacramento Municipal Utility District (SMUD)

Existing Resources

Sacramento Municipal Utility District (SMUD) is the second largest publicly owned utility in California. In 2006, SMUD expects to have 3,055 MW of dependable capacity to serve load obligations, 50 MW from interruptible and emergency programs, and another 150 MW from dispatchable demand response. SMUD forecasts 1,001 MW of utility-controlled fossil resources throughout the forecast period. This includes: McClellan 72 MW, Campbell's Soup 172 MW, Proctor & Gamble 163 MW, Carson Ice 94 MW, and 500 MW at Cosumnes Phase 1. SMUD's Upper South Fork American River Project supplies 647 MW large hydro and 41 MW of small hydro. By July of 2014, an additional 400 MW of renewable pumped storage at Iowa Hill may be online. Capacity from renewable contracts comes from Camp Far West 8 MW (small hydro), PPM Wind 19 MW, Keifer Landfill 8 MW, Calpine Geothermal 50 MW, and Snohomish PUD 36 MW. Other bilateral contracts total 1,132 MW in July 2006. This bilateral contract supply amount decreases each year to 315 MW in July 2016.

Peak Demand

SMUD's forecasts net peak demand for its bundled customers to be 2,938 MW in 2006, increasing to 3,535 MW in 2016. Demand is forecasted to peak in July of each year. For this peak resource requirement, the average annual increase over the forecast period is 1.9 percent. Near-term annual increases are highest: 2006-7 is 2.1 percent, and 2007-8 is 2.0 percent.

SMUD reports modest amounts of distributed generation as an adjustment to the load forecast. In July 2006, there will be 13.6 MW of distributed generation in place, an amount expected to grow steadily to 15.1 MW by July 2016.

Incremental Resource Needs

SMUD counts Cosumnes 1 as available by Jan 2006, though the plant's construction is delayed by a legal dispute with the project developer. Looking at line 48 "total capacity" and comparing with line 12 "firm peak resource requirement" shows that SMUD has surplus capacity until summer 2008, when small capacity deficits begin (4 MW in June, 5 MW in July, 21 MW in August, 20 MW in September). Surpluses remain throughout the non-summer months but re-appear each summer from 2009 through 2016.

Energy Requirements

SMUD's "Net Energy for Bundled Customers" have the same values as "Total Energy Requirement," with exceptions in 2005 and 2006 that account for firm energy sales (exchange). The Total Energy Requirements average annual increase over the period is 1.6 percent.

Renewable Resources

SMUD's Solano Wind Farm is located near Montezuma Hills Road in Solano County. The Wind Farm Project's 182 MW of capacity will be developed in phases between 2003 and 2011. Transmission service to SMUD is provided by PG&E through the CA ISO.

Solano Wind Farm Phase 1 is currently in commercial operation and generates about 46 GWh a year. The wind farm consists of 23 Vestas V47 wind turbines with a combined nameplate capacity of 15 MW.

SMUD estimates that the marginal wind resource needed to help reach a 28 percent eligible "renewables" target would cost SMUD an extra $15/MWh over what it would otherwise procure. This $15/MWh premium for eligible renewable resources is up from the current estimate of $5/MWWh. SMUD plans to add more wind to its Montezuma Hills land resource, using new 2 MW to 3 MW large turbines, but at a slower pace of development due to higher capital costs.

Resource Planning Strategy and Goals

The Sacramento Municipal Utility District has these resource planning principles:

- Reduce costs to customers and provide greater price stability.
- Improve reliability of its electrical system.
- Retain flexibility in evolving energy markets.

Uncertainties of Concern to SMUD

SMUD's Upper American River Project is subject to large year-to-year variations in hydro generation due to above or below average precipitation. Because of this variation and its impact on SMUD's supply budget, SMUD has weather hedge agreements to mitigate the financial impact.

Another uncertainty facing SMUD is the proposed annexation of the cities of Davis, West Sacramento, and Woodland in eastern Yolo County. The potential impact of this annexation was being studied by SMUD staff in April 2005, so this potential was not included or assumed in the supply Resource Plan submitted to the Energy Commission. A feasibility study commissioned by SMUD and the cities of Davis, West Sacramento and Woodland is currently available on the Internet at http://www.smud.org/annexation/beck_study.html

Spot Market Supplies

SMUD expects to rely on spot market purchases (beginning in July 2006) for about 100 MW, about 3.4 percent of its forecast peak demand. This use of short-term and spot-market purchases increases to 575 MW in 2013 but assumes that Cosumnes Phase 2 with 500 MW will not built.

Imperial Irrigation District (IID)

Introduction

Imperial Irrigation District (IID) is the sixth largest load-serving electric utility in the state, and operates one of four control areas located entirely within California. In response to the Energy Commission request for supply data, IID provided new information forms S-1, S-2, and S-3. Since this new information is in draft form and needs to be approved by the Board before it is made public, IID requested confidentiality for their submission for two years. Confidentiality was granted for the entire forecast horizon for the next two years, with the understanding that the information would be made public well before two years. IID also provided information on bilateral contract supplies using form S-5, but this information is not considered confidential. Along with other LSEs requesting Resource Plan confidentiality, the Executive Director requested that IID consent to a proposal that would allow aggregated summary tables to be published. IID granted this request, and energy and capacity tables were published in Energy Commission Staff paper CEC-150-2005-001 on June 29, 2005.

Much of the information presented below was compiled from IID's 2003-2004 Annual Report and press releases posted on the utility's website.

Existing Resources

IID-owned resources include: 24 MW of low-head hydro units along the All American Canal, 307 MW of gas-fired steam and combined cycle units, 162 MW of peaking gas turbines, and shares of other plants including 104 MW at San Juan and 14 MW at Palo Verde.

IID has a contract for 25 MW of firm capacity with Coral Power, LLC. This contract began on May 1, 2003 and expires December 31, 2007. The agreement is not unit contingent, is not dispatchable, and has no associated dependable capacity. This appears to be a 7X24 contract though it is not explicitly stated..

In September 2000, IID signed contract with Calpine Power Services Company for a 150 MW share of South Point Energy Center. This contract provides both capacity and energy through April 30, 2007.

Although IID's rates are not regulated by the FERC, as IID is non-jurisdictional, in a May 25, 2005 decision (Docket No. ER01-2887-003) on an updated market power analysis governing other purchasers, FERC concluded that South Point Energy Center satisfies FERC's standards for market-based rates, so that the next updated market power analysis is not due for three years.

IID recommissioned the Double Weir Mini Hydro Project, capable of generating 360 kW. It was scheduled to begin generating on April 19, 2005. The project was first commissioned in 1961, and taken out of service in 1986 due to mechanical problems. The $2.5 million project was funded by the Public Benefits Charge; it came in on schedule and $500,000 under budget.

IID can count on 14 MW of dependable capacity and 100 GWh of monthly energy from nearby Palo Verde Nuclear Station in Western Arizona.

Peak Demand

In 2004, IID served a peak load of 870 MW, with 1,050 MW (nameplate) of generating resources. The IID service area includes all of Imperial County, the Coachella Valley in Riverside County, and parts of Eastern San Diego County.

In 2003, the peak load at 4 p.m. on July 15 was 792 MW, a 7 percent increase over the previous peak in 2002. IID's projection for 2003 was 3 percent load growth. To cover the increase, the utility needed 100 MW of additional capacity, which was met with short-term contracts instead of its combustion turbines. In 2009, this net peak demand (not including a 15 percent planning reserve margin) is expected to be 1,064 MW. By 2016, net peak demand is expected to be about 1,334 MW.

For its uncommitted dispatchable demand response, IID plans to join other large energy users, offering financial incentives to help balance load during high-demand hours in the summer.

Incremental Resource Needs

In April 2005, IID announced expansion of its contract with Inland Energy Consulting to assist with RFPs and contract development for renewable and source supplies. Both RFPs are expected to be released in 2005.

In May 2005, IID announced that a one-month open season would be held in June 2005 for suppliers holding existing, valid contracts to provide energy and capacity from units not yet in commercial operation, allowing them to extend their existing agreements by one year. The open season could apply to a 20-year contract with Guepard Energy, Inc. for firm, unit contingent must-take energy from an as-yet-unconstructed 18 MW generation facility. The contract began in December 2003 and expires July 1, 2005.

In May 2005, the Board authorized IID Energy to begin construction of two generation facilities that will add 350 MW of capacity to the system. The projects were identified through a competitive solicitation. One project, scheduled to begin operation in 2008, is the Niland Combustion Turbine Project (100 MW), which can be expanded to a 140 MW combined-cycle unit. The second project is the repowering of El Centro Unit 3, converting it to a combined-cycle gas-fired unit and upgrading its capacity to 120 MW. Power deliveries are scheduled to begin in 2009. Total projected cost is $200 million.

Additional contracts are in negotiation, including a 10-year contract for 50 MW, with energy delivery beginning as early as 2006. IID is seeking four five-year contracts for 25 MW from a variety of producers. Of the four contracts, IID will seek three contracts with call options.

In general, IID expects that as peak demand grows, a new 50 MW gas-fired LM6000 unit could be added to the utility-owned generation portfolio roughly every two years.

Energy Requirements

Mid-range projections for load growth in the Imperial Valley and the Coachella Valley are 5.5 percent and 8.85 percent, respectively. The annual average increase was previously estimated at 5 percent, but actually exceeded 8 percent in 2004. A press release in June 2005 states that IID serves 122,000 customers.

Forecast energy demand for all of 2009 is estimated at 4,207 GWh. By 2016, annual energy demand is expected to grow to 5,271 GWh.

Renewable Resources

IID provided contract information for a geothermal facility. In 2001, IID announced a unit-contingent contract with CalEnergy for 170 MW Salton Sea Geothermal for 20 years from its commercial operation date. The project was delayed but is now expected to be online in 2006. The ramp-up was supposed to begin at 40 MW in 2005, reaching 170 MW in 2007. Delivery is must-take and year-round.

In January 2004, IID announced an interconnection agreement with CalEnergy Obsidian Energy LLC for access to generation from the Salton Sea Unit 6 Geothermal Plant (185 MW). Later press releases cite 200 MW of geothermal under contract. Although not required to comply with the state's renewable energy targets, IID's purchase of 200 MW of geothermal energy from Salton Sea 6 coupled with its existing geothermal and hydro generation, exceeds the state's principle renewable energy goal. That goal is for each LSE to supply 20 percent of its retail sales energy from renewable resources by 2017.

For the forecast period 2009-2016, energy demand is estimated to total 37,760 GWh. This number includes transmission losses, distribution losses, and "UFE" (unaccounted for energy), so it is slightly higher than ultimate retail sales numbers. In this same time period, IID expects to receive 12,416 GWh of geothermal energy from Salton Sea 6, plus 1,881 GWh from small hydro plants (less than 30 MW nameplate). Thus, these two sources of eligible renewable energy are forecast to provide 37.8 percent of the GWh needed to serve retail loads during this time. IID also expects to have 1,254 GWh from large hydroelectric resources.

Resource Planning Strategy and Goals

While IID provided the data requested on the electricity supply forms, the utility did not provide the requested statements about uncertainties, risk factors, or strategies it considers useful for addressing those concerns. IID was always cordial, professional, and responsive to information requests originating in Sacramento, and has been careful to provide information voluntarily, stating "Imperial Irrigation District does not acknowledge the jurisdictional authority of the agencies collecting this data to require municipally owned utilities and/or irrigation districts' compliance with this request …" Staff gratefully acknowledges the data and information provided by IID.

Uncertainties of Concern

None stated.

Spot Market Supplies

To address its ongoing need for access to spot market energy, IID joined Public Power Initiative of the West (PPIW) and jointly developed the http://www.westtrans.net website. The website sponsors celebrated their first year of operation on March 31, 2005. The website provides a single internet site where information is posted on available transmission capacity, and resources are posted for bidding and offline negotiations. The information is updated every hour.. The website organizes 20 public and private transmission providers in 13 western states seeking available transmission capacity to serve 5.5 million energy customers on 24 networks through 27,000 miles of power lines.

For the years 2009 through 2016, IID does not indicate an intention to use the spot market or short-term markets for dependable capacity.

Modesto Irrigation District (MID)

Existing Resources

Modesto Irrigation District (MID) has three utility-controlled fossil-fueled plants: McClure (two combustion turbines), Ripon (two combustion turbines), and Woodland (two combined-cycle units). Dependable capacity from these three plants varies only slightly throughout the forecast horizon: 330 MW during most months, and 327 MW for a summer derate.

MID's share of hydro capacity from Don Pedro is constant at 62 MW for all months except October and November, when it drops to 15 MW. New Hogan reservoir provides a constant 3 MW of small hydro supply. Modesto's total capacity from existing and planned resources is forecast to increase from 739 MW in August 2006 to 795 MW in August 2016.

For non-traditional "supply" resources, Modesto expects interruptible and emergency programs to help reduce loads by 22 MW from May through September in all years of the forecast period. Dispatchable demand response increases from 11 to 18 MW for this period.

Peak Demand

Modesto's firm peak resource requirement increases from 772 MW in August 2006 to 1,085 MW in August 2016. These figures include a 3 MW per month allocation for firm sales commitments, and a 15 percent planning reserve margin. A 62 MW purchase from Hetch Hetchy (City and County of San Francisco) is supplied with its own reserves. Like all other POUs, Modesto does not expect customer load to depart to direct access retailers or community choice organizations.

Incremental Resource Needs

Modesto plans to purchase small amounts of capacity from the spot market in two of the summer months in 2006. Spot market purchases may increase to 185 MW in Aug 2009. Modesto plans to add 150 MW of generic base load capacity in January 2010 after which spot market purchases will drop sharply. Another 50 MW of generic baseload may be added in Jan 2013 and Jan 2016.

Energy Requirements

The average annual energy increase for MID is 3 percent per year, going from 2,659 GWh in 2006 to 3,609 GWh in 2016. Wholesale energy sales are projected to remain at 10 GWh per year throughout the forecast horizon.

Renewable Resources

Modesto has two existing renewable supply contracts. Future Winds capacity maximizes in September in all years, and increases from 15 MW in 2006 to 29 MW in 2016. The High Winds contract (4 to 15 MW) expires in spring 2014. Modesto does not list any capacity from generic renewable resource additions. However, MID shows generic renewable energy supply beginning in 2011 with 74 GWh, increasing to 1,040 GWh in 2016.

Resource Planning Strategy and Goals

Modesto ID's portfolio is dominated by natural gas- fired generation, so MID hedges its gas portfolio to minimize the impact of gas price swings.

Uncertainties of Concern to Modesto ID

No statements about risk assessments were provided.

Spot Market Supplies

In the adverse hydro scenario, MID elects to add spot purchases to cover shortfalls in capacity as long-term contracts expire.

City of Anaheim, Public Utilities Department

Existing Resources

The City of Anaheim, Public Utilities Department owns only one thermal generating resource outright, Anaheim CTG, with 44 to 46 MW of dependable capacity. Anaheim has entitlements to power from out-of-state coal resources: Intermountain (IPP) Units 1 and 2 (236 MW), and San Juan 4 (47 MW). Anaheim takes 70 MW of baseload nuclear power from San Onofre Units 2 and 3 through most of 2009, but does not expect to continue its ownership share of that resource after the steam generator replacement project begins.

August is always the peak demand month for Anaheim. September peak demands are consistently 3 MW or 4 MW less than in August. For August 2006, dependable capacity of existing and planned resources are estimated at 586 MW, declining to 549 MW in August 2016. Anaheim does not show capacity for uncommitted dispatchable demand response, interruptible programs, or emergency programs.

Peak Demand

The firm peak resource requirement in August 2006, including a 15 percent planning reserve margin, is 641 MW. This total increases to 761 MW in 2016. These amounts are equal to Anaheim's net peak demand for its retail customers since Anaheim does not have firm long-term wholesale obligations.

Incremental Resource Needs

Anaheim shows a need for 171 MW of load-following and peaking capacity, starting in January 2008. Though listed as a generic need, this is a planned resource. With the inclusion of a 171 MW gas-fired resource addition, Anaheim's Resource Plan is able to cover it's August 2016 peak plus 58 MW of reserve. The expected energy from this planned resource varies by the month, starting with 29 GWh in June 2008 and growing progressively to 66 GWh by August 2016. Anaheim's Resource Plan includes energy from spot market and short-term purchases.

Energy Requirements

Total Energy Requirement for the year 2006 is 2,873 GWh. Total Energy Requirement for the year 2016 is 3,616 GWh. The Total Energy Requirement's average annual increase over the period is 2.6 percent.

Renewable Resources

Anaheim begins the 2006 forecast period with 21 MW of renewable resources under contract. This amount increases progressively to 64 MW by 2016. Monthly energy from these contract renewable supplies (wind, landfill, geothermal, and biomass) starts at 15 GWh in January 2006 and reaches 47 GWh in August 2016. This does not include 40 MW from Hoover, an important load-shaping resource for Anaheim that reliably supplies 2 to 6 GWh of energy every month. For the entire forecast period, Anaheim expects state-defined eligible renewable resources to supply 4,277 GWh, equal to 12 percent of its total energy requirement. Adding 487 GWh from Hoover would bring total renewable energy to 13.3 percent of total energy requirements.

Resource Planning Strategy and Goals

The bulk of Anaheim's Resource Plan consists of nearly 500 MW of utility-controlled fossil and nuclear resources. Over half of these resources consist of coal-fired imports from IPP Unit 1 and Unit 2 in Delta, Utah, and San Juan Unit 4 in Farmington, New Mexico. The IPP units and the importing transmission facilities such as the Southern Transmission System comprise Anaheim's largest single contingency. The Magnolia Power Project in Burbank will provide 118 MW (92 MW base and 26 MW peaking) of natural gas-fired generation. This plant is expected to come online in July 2005. The Anaheim CTG provides 46 MW of peaking capacity and is located within Anaheim's service territory. Anaheim's ownership in the San Onofre Nuclear Generation Station (SONGS) provides 70 MW of baseload capacity, but will be reduced to zero in 2009 when Anaheim elects to not participate in the proposed steam generator replacement project.

In its statements on risk and uncertainty, Anaheim describes its strategy for maintaining local reliability at reasonable cost, and adding locally-sited resources . Anaheim's portfolio is now heavily weighted to baseload coal and nuclear resources, with a reliance on imported power from Hoover for load-shaping. The potential value of locally-owned resources is magnified by Anaheim's lack of direct ownership in transmission. Following is an excerpt from Anaheim's narrative on managing risk and uncertainty:

> A small, but important component to Anaheim's Resource Plan is our 40 MW entitlement in the Boulder Canyon Project (Hoover Dam) as shown on line 17 of Form S-1. As the majority of Anaheim's portfolio consists of base load resources, the flexibility afforded by a large hydro unit provides Anaheim with much needed load shaping capacity. However, the ongoing drought in the western United States has highlighted the risk associated with poor hydrological conditions and the need for a diversified portfolio.

> Finally, 171 MW of capacity for load-following and peaking energy is included in Anaheim's Resource Plan on line 54 of Form S-1. This facility is expected to be a natural gas fired generation station located within Anaheim's service territory and is envisioned to begin operation in early 2008. The risks associated with powering a plant with natural gas appear outweighed by a reduction in transmission losses, lack of transmission constraints, local voltage support, self-provision of ancillary services, quick start technology, and load following capacity.

In summary, Anaheim's reference case is a fully resourced portfolio of diverse fuel types and generating technologies. It is designed to provide Anaheim's ratepayers with reliable service at the lowest possible cost, while meeting environmental obligations and contributing to the reliability of California's electric grid.[i]

Uncertainties of Concern to City of Anaheim, Public Utilities Department

Charles Guss, Integrated Resource Planner I for the City of Anaheim, Public Utilities Department provided the following comments.

> As Anaheim is a mature community with little undeveloped open space, load growth due to new industrial, commercial, and residential development is small. Energy consumption over the study period (2006 to 2016) is forecasted to grow by about 2.6 percent annually while peak demand is forecasted to grow by 2.3 percent annually. The increase in capacity factor as a result of differing growth rates is explained by expectations that consumer products, technological developments, and manufacturing techniques will become more energy-dependent in the future.

Major Uncertainties and Risk Analysis

Loss of large industrial or commercial customers due to an economic downturn would result in a loss of retail revenue proportional to the amount of exiting load. Anaheim expects to be able to offset some of this lost retail revenue through either a decrease in wholesale purchases or an increase in wholesale sales. Changes to our Resource Plan would be dependent upon the amount of lost load and planning reserve requirements.

The addition of large industrial or commercial customers due to economic growth would result in additional retail revenue proportional to the amount of additional load. In the short term, Anaheim would be able to serve this load through a reduction in wholesale sales and the inclusion of term purchases into its Resource Plan. In the long term, Anaheim might need to acquire additional renewable and non-renewable resources. Since Anaheim's service territory is largely built out, a substantial increase in demand due to new development is unlikely. However, a modest increase in demand due to advances in energy-dependent technologies is more plausible. The net financial affect of load growth beyond our load forecast is generally positive.

Wholesale Energy Prices

An increase in natural gas prices could potentially to increase Anaheim's total generation cost. Anaheim's long-term resource plans include 335 MW of natural gas fired generation as intermediate and peaking resources. Since Anaheim's resource portfolio includes a diverse fuel mix, the financial impacts from natural gas price fluctuations could be mitigated through reliance on more economic resources. The increase in wholesale electricity prices due to higher natural gas prices could also further mitigate the increase in generation costs through increasing wholesale sales revenue. However, the overall impact of higher natural gas prices would be higher generation costs. In terms of Anaheim's resource plans, a sustained increase in natural gas prices might cause Anaheim to shift away from natural gas peaking resources.

An increase in wholesale electricity prices without a corresponding increase in natural gas prices would increase Anaheim's net wholesale revenue. Anaheim's Resource Plan is increasingly self-sufficient and does not rely heavily on wholesale purchases to cover capacity and energy deficits. An increase in wholesale electricity prices would therefore increase Anaheim's wholesale sales revenue more than it would increase wholesale purchase costs. The net result would be an increase in wholesale revenue. However, higher ancillary service costs, higher transmission congestion costs, higher fees from the CA ISO, and higher fuel costs due to resource scarcity would offset some, if not all, this increase in net wholesale revenue. Higher wholesale electricity prices, therefore, may or may not necessitate a change to Anaheim's Resource Plan.

LSE Resource Portfolios

Anaheim has adopted a Renewable Portfolio Standard of 15 percent renewable by 2017. The renewable resources considered by Anaheim are generally base load or intermittent. Although these resources have comparable average costs to non-renewable resources, their operating characteristics make them difficult to incorporate into an already heavily base-loaded portfolio. Anaheim therefore has the tendency to "squeeze out" other base load resources with comparable costs. For example, Anaheim has chosen not to participate in the Steam Generator Replacement Program at the San Onofre Nuclear Generating Station and relinquish its ownership percentage, in order to pursue its RPS. A mandate to increase Anaheim's RPS percentage or speed up the timing would further exacerbate this problem.

In order to minimize risk to ratepayers, Anaheim generally maintains enough capacity to fully cover its monthly peak load forecast. During the summer months, when peak loads are volatile, Anaheim generally maintains more than enough capacity to meet forecasted peak load in order to mitigate the risk of unplanned outages and wholesale price spikes. A resource adequacy requirement of 15-17 percent above forecasted peak load would require Anaheim to acquire additional peaking and intermediate resources over its 10-year plan. In addition, a requirement to make unused capacity available to the CA ISO markets could lead to higher power supply costs for load serving entities that may not be fully recovered in the CA ISO markets.

Core/Non-Core – Departing Load

Loss of load from direct access, load aggregation or the application of the core/non-core customer service paradigm could result in a loss of retail revenue proportional to the amount of exiting load. Anaheim expects to be able to offset some of this lost retail revenue through a decrease in wholesale purchase volume or an increase in wholesale sales volume. Anaheim’s current Resource Plan is designed to serve all customers within its service territory, and changes to its Resource Plan would be dependent upon the amount of lost load and planning reserve requirements.

Riverside Public Utilities

Existing Resources

Throughout the forecast period, The City of Riverside (Riverside Public Utilities) can depend upon 136 MW of power from the Intermountain coal units in Utah. Riverside has 52 MW of nuclear power in its portfolio, including 12 MW from Palo Verde, and 20 MW from each of the two San Onofre units. Riverside expects to continue using San Onofre after its steam generator replacement project is complete; it is scheduled to begin in 2009. Among other fossil fuel resources, Riverside owns the 40 MW capacity Springs Units 1-4, and expects to have 96 MW of new simple cycle generation for peaking from RERC Units 1-2. Riverside can take 52 MW from coal-fired Deseret, under contract through 2009. Riverside has an ongoing 30 MW share of hydropower from Hoover Dam. Riverside also has diversity and firm energy exchange agreements with BPA that can provide 83 MW from May to October, and 31 MW in other months through 2010.

Peak Demand

August is normally the peak demand month. Riverside forecasts its peak customer demand in 2006 will be 539 MW (620 MW including a 15 percent planning reserve margin). This amount may steadily increase to 630 MW in 2016 (724 MW with a 15 percent planning reserve margin).

Incremental Resource Needs

Riverside anticipates that 55 MW of generic non-renewable peaking capacity will be needed by summer 2009, growing to 120 MW by 2012. About 45 MW of baseload capacity may be needed by mid-2010, plus 40 MW of load-following in 2011, growing to 60 MW of generic load-following need by 2013.

Energy Requirements

Riverside's total annual energy requirement, including up to 214 GWh of firm sales or exchanges, is forecast at 2,480 GWh in 2006, rising to 2,747 in 2016. August is the peak month for energy use, closely followed by September and July. Riverside expects to make modest purchases of short-term and spot market energy, especially in 2010, for 431 GWh.

Renewable Resources

Riverside begins 2006 with 27 MW of state-defined eligible renewable resources, including 20 MW from Salton Sea Geothermal Unit 5, through 2013, plus 7 MW from three local landfills, and 1 MW (dependable) of wind. These renewable resources are expected to produce 215 GWh in 2006, equal to 9.5 percent of its retail demand. The Resource Plan calls for 43 GWh of renewable energy in 2007 from generic resources. This amount increases to 431 GWh in 2014, and remains at 431 GWh in 2015 and 2016.

Resource Planning Strategy and Goals

Riverside utilizes a chronological production cost model to evaluate its potential resource mix solutions to meet certain planning criteria and targets. Among the targets are a 15 percent monthly planning reserve above the expected monthly peak, annual spot market purchases and sales projections of less than or equal to 10 percent of system requirements, Q3 heavy load spot purchase and sales volumes of less than or equal to 10 percent of system requirements, and renewable generation targets of 15 percent and 20 percent of retail load by 2010 and

2015,respectively. System requirements are defined as native load + transmission losses + third party obligations (primarily return obligations).

Uncertainties of Concern to Riverside Public Utilities

The following are the uncertainties of concern to Riverside Public Utilities:

- Load growth
- Renewable Portfolio Standard targets
- Spot market prices
- Regulation

Spot Market Supplies

Through 2008, Riverside includes only small short-term and spot market purchases for needed capacity, keeping this reliance under 1.5 percent. In 2009, this supply category grows in importance to 4.6 percent, and is in low double digits most years after that, peaking at 14.7 percent of the firm peak resource requirement in 2014. As stated in the supply filing:

> While Riverside plans to procure sufficient capacity to meet its expected monthly peak obligation plus a 15 percent reserve margin on a forward basis, spot market energy is a viable component of Riverside's supply portfolio. To minimize the price risk associated with potentially volatile spot energy prices, a 10 percent threshold is defined in Riverside's Energy Risk Management Policy. It is desirable to balance both spot energy purchases and sales within the 10 percent limit to effectively hedge uncertainty in power costs. Due to the expected addition of 96 MW of new simple cycle generation, spot energy purchases are forecasted to be minimal, with potentially sizable volumes available for surplus sales on average summer days when economic.

Turlock Irrigation District (TID)

Existing Resources

By the beginning of the forecast period in 2006, Turlock Irrigation District (TID) will have three utility-controlled fossil-fueled resources: Walnut (52 MW), Almond (49 MW), and the new Walnut Energy Center which is rated 250 MW nameplate, 265 MW dependable in winter, 240 MW dependable in summer, and 252 MW dependable in shoulder months. Turlock has three hydro power plants in its portfolio: Don Pedro (134 MW, not including the 31.66 percent share owned by Modesto ID), La Grange (12 MW), and Turlock Lake (3 MW). Turlock has bilateral supply contracts with Calpine for 50 MW through May 2008, which generally include 35 MW of baseload from the Sutter Plant. Turlock can count on 58 MW from Power Resources Cooperative through 2018. WAPA supplies another 4 to 6 MW. During the summer months, Turlock receives 10 to 28 MW from Hetch Hetchy (City and County of San Francisco), as scheduled by PG&E. Turlock ID also has 6 MW to 8 MW of geothermal capacity from NCPA.

For July 2006, Turlock expects to have 661 MW available from existing and planned resources. This amount of dependable capacity declines to 611 MW in July 2016 due mainly to expiration of existing bilateral contracts.

Peak Demand

Turlock expects net peak demand for its bundled customers will be 482 MW in August 2006, increasing to 556 MW in August 2016 (not including a 15 percent planning reserve margin). Turlock did not report having capacity available from interruptible/emergency programs, or from dispatchable demand response programs.

Incremental Resource Needs

The filing by Turlock shows 6 MW of generic renewable capacity starting in January 2006 and remaining at 6 MW through 2016. However, forecast amounts of generic renewable energy rises from 3.9 GWh to 25.4 GWh during this same period. A need for generic non-renewable peaking capacity first appears in August 2013, estimated at 14 MW. This generic capacity need grows to 23 MW in 2014, 33 MW in 2015, and 42 MW in 2016.

Energy Requirements

For 2006, Turlock's estimated total energy requirement is 1,920 GWh. Turlock's total annual energy requirement is predicted to have an average annual increase of 1.68 percent over the forecast period. For 2016, Turlock's total energy requirement is estimated to be 2,242 GWh.

Uncertainties of Concern to Turlock Irrigation District

These comments about uncertainties and risk were provided Nancy Folly, Utility Analyst, with Turlock Irrigation District.

The amount of capacity of the Walnut Energy Center (currently under construction) will likely vary once construction is completed and the unit is running. Another line item with uncertainty is our load. Our load forecast was updated in 2004. However, severe weather conditions and other factors are cause for uncertainty within the forecast.

The last point of uncertainty lies within the capacity number provided for our “Generic Renewable Resources”. The Turlock Irrigation District Board has set a target of 20 percent of Retail Sales by 2017 come from renewable sources. The amount of capacity to be acquired is unknown at this time. Turlock Irrigation District is currently evaluating several different [renewable energy] scenarios.

Uncertainty about the actual monthly resource mix is inevitable. Market power and gas prices along with hydro availability could cause our dispatch of resources to change.

There are several other factors that will affect Turlock Irrigation District resource planning. Locational Marginal Pricing will affect the District’s operations. Turlock Irrigation District is expected to be operating our own Control Area in the near future. The dispatch of our resources may change in order to meet our control area requirements.

Silicon Valley Power (SVP)

Existing Resources

The City of Santa Clara’s electric utility is now known as Silicon Valley Power (SVP). Silicon Valley Power has 281 MW of thermal resources, including Pico (148 MW), Gianera combustion turbines (50 MW), plus shares of NCPA geothermal, and San Juan (coal). Hydro resources vary from 178 to 252 MW, depending upon month. This level of hydro resources would be lowered by 74 MW under 1-in-10 adverse (critically dry) conditions. In August 2006, SVP’s existing and planned resources will total 541 MW, including 57 MW of geothermal capacity, and a 25 MW wind contract is under negotiation. This total of existing and planned resources declines by August 2016 to 526 MW. Geothermal resources diminish by 13 MW over this forecast period. SVP also reports an 8 MW interruptible program. Beyond the first few years, SVP includes no spot purchases in its Resource Plan.

Peak Demand

For 2006, Silicon Valley Power forecasts its net peak demand for its bundled customers will be 435 MW (500 MW including a 15 percent planning reserve margin). By 2016, this amount increases to 513 MW (590 MW with reserves). No uncommitted demand-side resources are expected. Nor does SVP anticipate making firm sales obligations, or departures of existing retail customer loads.

Incremental Resource Needs

Planning reserve margins under 1-in-2 hydro are 43.2 percent in 2006 (26.2 percent under 1-in-10 hydro). In the absence of additional procurement, this planning reserve margin declines to 18.9 percent in 2016 under 1-in-2 hydro conditions. Under 1-in-10 hydro and no additional procurement, SVP would still have a 15.8 percent planning reserve margin in 2010, and 4.5 percent in 2016.

SVP indicates a baseload need beginning in 2009, but the indicated capacity is primarily for shoulder month needs (July, August needs do not exceed 50 MW under 1-in-10 hydro until 2014), and is less than 100 MW through 2016.

Annual energy needs begin in 2009 at 275 GWH, increasing steadily to 556 GWh by 2016, or 10 percent to 17 percent of the total energy requirement, respectively. SVP identified the capacity they need as baseload capacity (i.e., non-peaking). Energy purchases would likely be contractual purchases of shoulder month energy from baseload sources.

Energy Requirements

Because SVP has neither expected uncommitted demand-side resources nor expected loss of load to ESPs, CCAs, or firm sales obligations, SVP's “Forecast Total Energy Demand,” “Net Energy Demand for Bundled Customers,” and “Total Energy Requirement” are all the same. Total Energy Requirements average annual increase over the period is 1.7 percent. Near-term annual increases are highest: 2006-7 is 3.3 percent, and 2007-8 is 1.8 percent. Afterwards, annual average growth in energy use is 1.5 percent per year.

Renewable Resources

SVP has 29 MW of small hydro, 57 MW of NCPA geothermal, and a pending 25 MW wind purchase. State-defined eligible renewable energy supplies equal 27.1 percent of total demand in 2006, gradually decreasing to 19.7 percent in 2016. If Silicon Valley’s 165 MW of large hydro is included in the renewable total, supplies would total 48.9 percent of load in 2006, declining to 38.1 percent in 2016.

Resource Planning Strategy and Goals

The City of Santa Clara does business as Silicon Valley Power (SVP) and has these internal goals and commitments:

- Provide its customer-owners with reliable, cost-effective electric service through local acquisition and local control of electric resources.
- Minimize its dependence on fossil and nuclear generation in favor of renewable energy sources.
- Support legislative and regulatory policies that will lead to overall market stability and predictability.
- Attain self-sufficiency in response to the uncertainty and volatility of energy supply and prices arising from a restructured electric market in California.
  - The primary reason for this approach is that there is no strong evidence that [shows], over the forecast period, electric energy or capacity will be readily available when and where needed, or that the price of such energy and capacity will be stable.
    - Nevertheless, Santa Clara must depend on others for a significant portion of its generation and transmission needs.
    - In response, Santa Clara carefully considers the stability and commitment of its suppliers in providing what Santa Clara cannot provide or build itself.

Uncertainties of Concern to Silicon Valley Power

The major short-term variables confronting Santa Clara include:

- Annual and monthly variations in energy and capacity availability from Santa Clara's hydro-based resources.
  - SVP estimates that it must prepare to replace up to 300 GWh over the course of a dry hydro year, and may be subject to unavailability of up to 136 MW of its WAPA contract capacity under certain conditions.
  - Consequently, SVP has necessarily planned for capacity reserves and energy availability that at first glance appear to be "high" compared with systems consisting primarily of thermal generation.

- Capacity unavailability due to scheduled and unscheduled outages.
  - SVP's resource planning and operations are designed to be consistent with WECC standards.
  - SVP's resource planning and operations are designed to be consistent with obligations under its Metered Sub-System (MSS) agreement with the California Independent System Operator (CA ISO).
- Changes in energy demand due to weather variations, specifically hot temperatures.
  - SVP's loads are moderately sensitive, increasing by about 2-3 MW for each degree of temperature.
  - A 100 degree day is likely to increase SVP's 400 MW peak load forecast to about 407 MW. This is well within SVP's capacity availability.
- The relationship between short-term wholesale electric energy prices and Santa Clara's variable cost of energy, particularly gas-fired energy, from its own resources.
  - In real time, SVP seeks to minimize its cost of production but retains a preference to purchase from the wholesale market when the net effect is to reduce SVP's total variable cost of energy production and purchases.
  - However, for planning and financial reasons, SVP's primary objective is to maintain a generation and transmission portfolio that provides both physical and financial stability.

Roseville Electric

Existing Resources

The only two utility-controlled fossil-fuel thermal resources currently in the portfolio of Roseville Electric's are shares of plants managed by the Northern California Power Agency (NCPA). Roseville can count on 21 MW from NCPA's STIG Unit, plus 16 MW from the NCPA CT Unit. The Roseville Energy Park is scheduled to begin operation in April 2007 with 162 MW.

Roseville has a 78 MW share in NCPA's large hydro plant, Collierville, on the upper Stanislaus River, plus a 10 MW share in NCPA's geothermal resources.

Roseville takes energy and firm capacity from two contract suppliers: up to 43 MW from Morgan Stanley through 2010, and up to 7 MW exchange with SCL.

Roseville Electric's total existing and planned capacity in July 2006 is 348 MW, including bilateral contract supplies. This amount of total capacity increases to 441 MW in July 2014, the last peak month shown on Roseville's data submittal.

Peak Demand

Roseville forecasts its net peak demand for its bundled customers will be 134 MW in July 2006, increasing to 170 MW in 2014. The peak month is always July in the forecast.

Incremental Resource Needs

Roseville expects to be adequately resourced through 2014, mostly using utility-owned thermal generation, power pool resources (from the Northern California Power Agency), and bilateral contract supplies.

Roseville did not submit a "balanced" resource plan that includes a 15 percent planning reserve margin. The total peak requirement includes all the forecast peak demand for its bundled customers, and a modest 4 MW to 15 MW for firm sales obligations, but does not include a single megawatt for a planning reserve margin. What also makes the load-resource tables "unbalanced" is that a matching supply resources to account for this planning reserve margin has not been added to the categories on the form for this purpose: generic renewable capacity, generic non-renewable capacity, or short-term and spot market purchases. The resource tables provided by Roseville do include short-term and spot market purchases of capacity and energy, and do not, unfortunately, list any generic resource additions needed to serve firm load and maintain the 15 percent planning reserve margin. Fortunately, these minor omissions (which are not unique to Roseville) are not large numbers. The "net short" in 2006 would be 15 MW in 2006, 36 MW in 2007, and 17 MW in 2008. For 2009 through 2014, the calculated net short amount of needed generic capacity is either 9 MW or 11 MW.

Energy Requirements

For 2006, Roseville's total energy requirement is 1,319 GWh. The average annual increase in energy during the forecast period is 2.5 percent. In 2014, Roseville expects to need 1,660 GWh to meet its load and delivery obligations.

Renewable Resources

In 2006, Roseville expects 96 GWh from its geothermal, landfill gas, and wind resources under contract, equal to 7.5 percent of its net annual demand for retail load. Roseville also forecasts taking 236 GWh from the Collierville hydro plant, which would equal 18.4 percent of total retail demand. Roseville does not have plans to add generic renewable resources during the forecast period.

Uncertainties of Concern to Roseville Electric

As the new Roseville Energy Park moves towards construction, Roseville is concerned with natural gas fuel supply, pipeline delivery and storage costs, and the potential failure of counterparties to fulfill their gas delivery arrangements. These uncertainties pose a financial risk to the City of Roseville. Roseville does not yet have in place firm gas supply and transmission arrangements to meet all the Roseville Energy Park fuel supply needs, and is therefore exposed to some price volatility for such commodities and services. To mitigate such risks, the City of Roseville has developed a fuel supply management strategy focused on reliability and price risk management.

The new Roseville Energy Park will allow the city to reduce its dependence on the forward purchase market. Roseville expects to reduce forward purchases so that such purchases will be eliminated by 2012. This will reduce Roseville’s price risks related to these forward markets. Roseville Energy Park will help reduce short-term market purchases from 493 GWh in 2006, to 212 GWh in 2007, and 65 GWh in 2008.

Pasadena Water and Power

Existing Resources

Pasadena Water and Power (Pasadena) controls two fossil-fueled plants with 199 MW available for local dispatch: 65 MW from Broadway 3 (through 2013), 47 MW from Glenarm Units 1 and 2 (through 2014), and 87 MW from Glenarm Units 3 and 4 (through at least 2016). Pasadena has a 19 MW share of the Magnolia plant in Burbank, expected to go online in July 2005. Pasadena can call upon a 20 MW share of Hoover hydropower, and counts another 15 MW from small hydro units. Contracts for energy from landfill gas, Ormat Geothermal, and PPM Wind add about 7 MW to the supply portfolio.

Pasadena has several long-term bilateral contracts including a dependable 107 MW from Intermountain in Utah, 10 MW from Palo Verde in Arizona. Pasadena has contracts with BPA that include must-take energy in May and June, and energy exchange options (daily and seasonal exchanges) in other months. Up to 27 MW is normally available from BPA during peak hours of summer months. Bilateral Contract capacity totals 144 MW in 2006 MW, and declines to 117 MW in 2016 due to contract expirations.

In August 2006, Pasadena's total dependable capacity from existing and planned resources totals 403 MW. This total will hold at 393 MW in the summer months of 2013, but declines in subsequent years as the Broadway 3 and Glenarm Units 1 and 2 retire.

Peak Demand

Pasadena estimates net peak demand for its bundled customers will be 299 MW in 2006, increasing to 330 MW in 2016. August is modeled as the peak demand month, though estimated demand for both July and September are within 4 MW of the August peak.

Incremental Resource Needs

Total existing and planned resources in August 2006 are 403 MW (equal to a 34 percent planning reserve margin). With these same resources, and modest load growth, Pasadena expects to maintain a 24 percent planning reserve margin through August 2012. In 2014, Pasadena predicts that 60 MW of generic non-renewable load-following or peaking capacity will be needed, with another 60 MW needed in 2015.

Energy Requirements

The outlook for average annual average energy use in Pasadena is 0.2 percent growth per year, from 1,338 GWh in 2006 to 1,373 GWh in 2016. Pasadena has no expected uncommitted demand side resources or expected loss of load to ESPs or Community Choice Aggregators over the forecast period.

Renewable Resources

Pasadena has 15 MW from small hydro plants, and a 20 MW share of Hoover, but does not own or control other renewable generation. Despite having a capacity resource surplus through 2013, Pasadena anticipates adding 3 MW per year of generic renewable capacity starting in 2009. Over the entire forecast period, Pasadena expects that state-defined eligible renewable resources will provide 11 percent of the total energy requirement. This figure rises to 15 percent when energy from Hoover dam is included.

Resource Planning Strategy and Goals

Not provided.

Uncertainties of Concern to Pasadena

- Actual load growth may be greater than the growth rate projection.
- Uncertainty due to Pasadena's recent membership in the CA ISO as a participating transmission owner.
- Availability of natural gas.
- Stability and availability of renewable resources.
- Drought conditions in the Southwest.
- California NO_x, CO_2, SO_x, and ROG emissions restrictions.
- Reinstatement of deregulation.

Spot Market Supplies

Pasadena does not expect to purchase capacity from the short-term or spot markets until the second half of 2015. However, Pasadena does expect to use these markets for energy purchases throughout the forecast period, probably for economic reasons, for about 4 percent of its total energy needs.

Glendale Water & Power

Existing Resources

Glendale's' dependable fossil capacity varies slightly over the forecast period. Glendale's gas-fired Grayson units generate 249 MW as needed. Glendale has a 40 MW share of Magnolia, expected online in July 2005. Coal-fired power imports from Intermountain and San Juan provide 38 MW and 20 MW, respectively. Glendale also takes 11 MW of baseload nuclear power from Palo Verde, and up to 20 MW of hydropower from Hoover.

Contractual resources include 50 MW in summer months from Portland General Electric, through September 2012, and 10 MW from BPA through April 2008. In these exchange contracts, capacity and energy are returned north during off-peak winter months.

Existing and planned resources in September 2006 total 458 MW, including 4 MW of landfill, 3 MW of geothermal, and 3 MW from a wind contract. Glendale includes no spot market or short-term purchases in its forecast.

Peak Demand

In 2006, Glendale's projected net peak demand for bundled customers is 286 MW (338 MW including reserves). By 2016, this increases to 334 MW (384 MW with reserves). No firm sales obligations are expected. Peak demand is forecast to occur in September, with August peak demand close behind.

Incremental Resource Needs

For 2006, Glendale will apparently have a planning reserve margin equal to (155.8) [this number must be wrong] percent of forecast peak load requirements. Glendale's total capacity from existing and planned resources declines to 388 MW after September 2012 and remains static through 2016 but is still sufficient to maintain a 15 percent planning reserve margin (which would be 384 MW in September 2016). Glendale therefore has no need to add generic resources during the forecast period.

Energy Requirements

Glendale's average annual average growth is 1.1 percent per year. Total deliveries are forecast to increase from 1,297 GWh in 2006 to 1,443 in 2016. Glendale has no expected uncommitted demand side resources, or expected loss of load to ESPs or CCAs over the forecast period. Monthly energy demand is forecast to peak in August and ebb in March.

Renewable Resources

Glendale forecasts it will annually take 71 GWh or 72 GWh from its 20 MW share of Hoover, along with 65 to 78 GWh from other renewable resources (Chiquita Canyon Landfill, Ormat Geothermal, and PPM Wind). Glendale does not have a plan to add additional renewable resources to its portfolio. Averaged over the entire forecast period, renewable energy supplies amount to 11.4 percent of Glendale's net energy demand for bundled customers when Hoover is included. Without Hoover, the state-defined eligible renewable resources will supply about 6 percent of retail load requirements over the forecast period.

Resource Planning Strategy and Goals

Glendale Water & Power (GWP) supplies power to the City of Glendale, using the utility-owned Grayson Power Plant generating units, long-term power supply purchase contracts, and spot energy purchases. Recent history indicates that Grayson Power Plant generates approximately 15 percent of Glendale's energy requirements. The remaining 85 percent of the energy requirements are mostly purchased from power generating projects outside the Los Angeles Basin.

Glendale also has significant long-term power purchase resources. The Department has a total of 209 MW net capacity entitlements in seven power projects and three firm power arrangements. GWP also has firm transmission from the Southwest U.S. through its participation in SCPPA projects, and a firm transmission ownership entitlement in the Pacific Northwest DC.

Natural gas and landfill gas are the primary fuels for local generation.

Glendale has no planned transmission facilities for the next 10 years.

Uncertainties of Concern to Glendale

Glendale Water & Power (GWP) realizes there are many uncertainties which could significantly affect its forecasts for future load and energy requirements. Among the unpredictable events acknowledged by GWP:

- A war or major armed conflict.
- An oil or natural gas embargo.
- A major earthquake or natural disaster.
- Severe weather conditions: prolonged drought or El Niño conditions.
- Hyper inflation or collapse of the national economy.
- A major technological breakthrough altering the methods or economics of energy delivery or production.

All these events are unpredictable in timing and effect. GWP operates in a prudent, fiscally sound manner and updates its forecasts regularly to take account of developing changes. GWP feels it is not cost effective for its small staff to develop scenarios for these events.

Spot Market Supplies

Glendale reported no spot market capacity purchases on form S-1, but did report forecast spot energy purchases on form S-2 in all years, in amounts that gradually increase to 33 GWh in August 2016.

City of Burbank, Department of Water and Power

Existing Resources

Burbank reports 350 MW of dependable supply capacity for every July in the forecast period. Major thermal resources include Burbank's share of Intermountain Power Project (Coal) 75 MW, Burbank's share of Palo Verde (Nuclear), 10 MW, Magnolia Power Project (Gas), 96 MW (expected online July 2005), Olive 1 (Gas)

44 MW, Olive 2 (Gas), 55 MW, and Lake 1 (Gas), 47 MW. Burbank does not anticipate adding any other thermal resources during the forecast period.

Peak Demand

Demand is forecasted to peak in July of each year. Net peak demand for bundled customers is 283 MW in July 2006, increasing to 336 MW in July 2016. Burbank's peak resource requirement shows a consistent increase of 1.5 percent per year over the forecast period.

Incremental Resource Needs

Burbank expects to add incremental Q3 resources as the need arises. However, Burbank's filing data does not reflect any resource additions during the forecast period (2006-2016). Existing and planned capacity are less than 115 percent of forecast demand in each July starting in 2008, and in each August starting in 2010, and in each September starting in Sept 2012. The planning reserve values for July, August and September, 2016 are, respectfully, 3.9 percent, 6.2 percent, and 8.6 percent. It is clear from the submitted data and subsequent communication with that Burbank will add additional resources on a timely basis to maintain adequate planning reserve margins.

Energy Requirements

Burbank expects energy demand will continue to grow at about 1.5 percent per year for the next several years. Burbank's "Forecast Total Energy Demand" (S-2, line 1) shares the same values as "Net Energy Demand for Bundled Customers" (S-2, line 8) for all values in the forecasted period. These values grow by 1 percent per year over the forecasted period. The only exceptions occur in calendar years 2007 (0.9 percent) and 2008 (0.6 percent). Burbank's S-2 line 9 shows its firm sales obligations from January 2006 through April 2008. When firm sales obligations are added to "Net Energy Demand for Bundled Customers," the total exactly matches the "Total Energy Requirement" (S-2, line 10).

Renewable Resources

No data listed on Form S-2, lines 18, 26, 42 or 52. No small (less than 30 MW) hydro energy is listed.

Burbank asserts it has a commitment to achieve state RPS goals that currently apply only to IOUs.

> “Burbank has adopted a Renewable Portfolio Standard which commits the utility to procure 20 percent of its energy needs via renewable resources by the year 2017. The end goal is clear. However, we do not have a firm plan on when to bring on additional renewable resources. With the addition of the Magnolia Plant in its portfolio Burbank has sufficient resources to meet the expected load growth over the next few years. We expect to incorporate additional renewable energy as supported by demand growth.”

The resource planning data on Burbank’s Form S-2 does not match the expectation that renewable resources will be added as demand grows. It appears from form S-2 that the total renewable energy component (ignoring large hydro) does not rise above 2.0 percent in any month of the forecast. (This calculation adds line 40 “total renewable resources” to line 23 “total renewable contracts” on Burbank’s Form S-2, and divides that sum by line 8 “net energy demand for bundled customers). If large hydro (greater than 30 MW nameplate) resources are counted as renewable, then the percentage grows a bit to a high of 4.2 percent (This second calculation adds the quantities on line 40 “total renewable resources” + line 23 “total renewable contracts” + line 15 “total for all hydro plants over 30 MW” from Burbank’s Form S-2, and divides that quantity by line 8 “net energy demand for bundled customers).

Resource Planning Strategy and Goals

The narrative does not specify any goals or planning strategies. Burbank typically uses a 50 MW planning reserve margin target. “For 2006, 50 MW would have us at a 17.7 percent [planning] reserve margin.”[ii]

Uncertainties of Concern to Burbank

How Burbank might add renewable resources to its supply portfolio is recognized as a major planning uncertainty. Two others are considered significant: fuel costs and future load growth.

> “Burbank will self-generate a sizable portion of its energy needs via gas-fired resources. As such, the utility faces uncertainties in both the future cost and availability of the commodity. Should current fuel prices continue to rise and become sustained at high levels our dispatch of our generating units may change if we could secure cheaper power from the market.”

> “Burbank has witnessed erratic fluctuation in annual peak demand over the past few years. Burbank’s historic peak demand was 284 MW in 1998. Subsequently, annual peak loads have remained high in the 260 MW level range.”[iii]

Spot Market Supplies

According to Form S-1, Burbank does not rely on "Short-term and Spot Market Purchases" for any dependable capacity. On Form S-2, line 45, Burbank indicates an unusual use of monthly short-term and spot market energy purchases. The largest purchases are forecast for the months of May, which has the cheapest wholesale prices from abundant hydro supplies in wet years. The months of August are second highest in volume purchases, and are more likely to relate directly to monthly energy demands, which also peak in August.

Redding Electric Utility (REU)

Existing Resources

The Redding Power Plant is rated 132 MW of dependable capacity in the summer months (139 MW in other months) with 135 MW nameplate. Five units of varying sizes and types allow for delivery of baseload, load-following, and peaking energy. In conjunction with the Modesto Irrigation District and Silicon Valley Power, Redding has a 22 MW ownership share in San Juan Generating Station in New Mexico. This coal-fueled resource provides year-round baseload energy to PacifiCorp that is subsequently delivered to Redding during the high-peak summer months.

Redding's website reports that a significant portion of the utility's energy supplies come from hydroelectric plants, especially Shasta Dam and points north. WAPA provides 104 MW in July and at least 70 MW in October. In its bilateral contracts, Redding reports three other supplies: 50 MW from PacifiCorp (through 2015), 25 MW from American Electric Power (through 2014), and 13 MW from the City of Shasta Lake (in 2006 only).

Peak Demand

Redding Electric Utility is the smallest LSE in California required to file electricity supply forms. In 2006, Redding's firm peak retail demand is expected to exceed 200 MW only during June, July, and August. Redding's peak demand month is July, by a wide margin. Peak power demands in July, including a 15 percent planning reserve margin and firm sales obligations, are forecast to rise from 304 MW in 2006 to 369 MW in 2015.

Incremental Resource Needs

Redding's existing resources will be adequate to serve forecasted load through 2010. This includes a 15 percent planning reserve margin, plus firm exchange obligations. 10 MW of wind resources have been added for delivery in 2007. By 2010, Redding expects to need 25 MW of generic non-renewable capacity in order to maintain the 15 percent planning reserve margin.

Energy Requirements

Redding's annual energy requirements (including firm sales obligations and exchanges) fluctuate between 1,130 GWh in 2006 to 1,064 GWh in 2016, with a low of 971 GWh in 2008 and a high of 1,109 in 2015. July is modeled as the peak month for energy demand, but August is close behind.

Renewable Resources

For the entire forecast period, Redding expects to supply 51 percent of its total retail customer needs with renewable energy. However, only 1.0 percent of its retail sales will be served by energy from Redding's 3 MW Whiskeytown Hydro Plant (100 GWh). Most of Redding's renewable energy (2,827 GWh in 11 years) will come from WAPA, with a portfolio of 97 percent large hydro and 3 percent small hydro. Redding has purchased 10 MW of renewable wind resources for delivery in 2007 to produce approximately 86 GWh annually through 2016.

Resource Planning Strategy and Goals

Redding Electric Utility (REU) holds several long-term contractual agreements for the delivery of power over high voltage transmission lines. All contracted deliveries are firm, fixed, and hold firm physical or owner-ship-like rights for delivery over the California-Oregon Transmission Project, the Pacific AC Intertie, or the Western Area Power Administration's (Western) Central Valley Project Transmission System.

Uncertainties of Concern to Redding Electric Utility (REU)

REU incorporates several uncertainties into its energy forecasting process. The greatest uncertainties relating to energy deliverables include fuel price volatility, hydrologic conditions, and future transmission availability. Energy values have been assessed using conservative estimates for fuel prices derived from the latest market trends, forward price curves, and staff estimates. REU has also sought solutions to hydrologic volatility by constructing local generation and signing long-term fixed contracts from alternative generation sources.

REU actively engages in portfolio diversification and risk mitigation strategies in order to minimize risks and optimize price - keeping costs low and reliability high. Redding evaluates other risks including regulatory, environmental, and electric market structure changes. Redding is also adapting to its resource planning and risk mitigation protocols in its new position in the SMUD/Western Control Area.

Spot Market Purchases

REU's system is energy sufficient while capacity resources are in line with the accepted planning reserve standard of 15-18 percent of peak load plus firm sales obligations. Wholesale spot-market purchases are kept to a minimum. Redding does not consider reliance upon California's short-term energy markets to be a prudent choice. REU forecasts the use of wholesale market purchases only for asset optimization.

Energy Service Providers

APS Energy Services
Constellation NewEnergy
Pilot Power Group, Inc.
Sempra Energy Solutions
Strategic Energy, LLC

The monthly, resource-specific data collectively comprising the Resource Plans has been granted confidentiality for four of these ESPs. This includes specific forecast data and company assessments about uncertainties and strategies to manage business risks. One company did not seek confidentiality for its information. Therefore, the attributes of these Resource Plans are summarized in only general terms or using aggregate numbers. Specific assessments are included without company attribution.

Existing Resources

Energy service providers do not, as part of their normal business plans, use company-owned generation to supply retail customer load. These companies carefully match wholesale power supply contracts to align with retail demand obligations, end-use load forecasts, and their strategic business plan. These supply contracts can be complex, short-term, mid-term, or long-term, and can involve more than one supplier of generation. Power suppliers may include merchants, power pools, power marketers, and utilities (publicly and investor-owned) who may be active in these private, bilateral markets. For four of these companies, details about these bilateral contract supplies have been granted confidential status until 2016 or the contract end of term, whichever is later.

APS Energy Services is affiliated with Arizona Public Service Company which does own generation in Arizona.

Sempra Energy Solutions (SES) is an energy service provider that is a separate company but affiliated with Sempra Energy. Sempra Energy also happens to be the corporate parent of San Diego Gas and Electric (SDG&E) and the Southern California Gas Company.

Peak Demand

For 2006, these five companies estimate their collective peak retail demand (not including a 15 percent planning reserve margin) will be 1,207 MW (see Figure 5-6). This is an estimate of the “most likely” case, including the peak demand for likely new customers, plus the expected demand of current customers who renew or extend their direct access contracts. This collective estimate of “most likely” non-coincident peak demand is 1,115 MW in 2016.

The peak demand month for these five companies may be in July, August, or September. For some companies, demand in June, July, August, September and October is only slightly less than their peak demand month.

At least one company was reluctant to forecast future retail demand beyond current contractual obligations. This reluctance to estimate precise monthly numbers out 11 years was attributed to substantial uncertainties about legislation, regulatory requirements, and competitive electricity market conditions. The filing from at least one company simply left blank cells on the spreadsheet for the last eight years in the forecast period. At least one ESP, however, has subsequently updated their demand forecast, providing the Energy Commission with more complete data.

Incremental Resource Needs

In the Resource Plans filed by all ESPs, there appear to be substantial variation in the specificity of plans to serve existing and planned customer loads. Several ESPs explicitly indicated a commitment to maintain a 15 percent planning reserve margin for their firm obligations, while some others did not report having secured enough resources to cover existing loads.

For most months in the forecast period, ESPs plan to meet projected resource requirements using mid-term bilateral contracts, or short-term and spot market purchases, or generic resources. These generic resources could be entirely baseload or load-following non-renewable supplies, acquired from bilateral contract suppliers. One company forecast a constant 50 percent of its energy and capacity needs would be supplied by short-term bilateral contracts or spot market purchases. Another company disclaimed any intent to rely upon short-term or spot market purchases for needed capacity, stating, “We purchase to the peak of our requirement, we do not anticipate needing to buy to cover our peak load."

One company asserted a lack of reliance on short-term and spot market purchases for needed monthly energy, stating, “We have met all our future obligations and will not purchase bi-lateral contracts unless we sign more customers." Collectively, ESP filings show a need for generic capacity resources that totals 259 MW in 2006, 300 MW in 2009, and 423 MW in 2016. These amounts are shown in Figure 5-4.

One company submitted load-resource tables that are "unbalanced" in that a matching supply resource is not listed in the categories on the form for bilateral contracts, generic renewable capacity, generic non-renewable capacity, or short-term/spot market purchases. While that company provided confidential data on its bilateral contracts, using form S-5, this company did not include capacity values on form S-1, or energy value totals on form S-2. It became apparent that future demand by potential new customers, and future demand of existing customers with new contracts, will have to be met by using some combination of bilateral contracts and spot market purchases.

One company submitted plans to secure sufficient resources to meet its projected firm resource requirements using renewable contracts, other bilateral contracts, and modest use of short-term and spot market purchases. This last category will likely provide about 11 percent of its estimated capacity needs, and about 4 percent of its estimated energy needs.

At least one company plans to secure sufficient resources to meet its projected firm resource requirements entirely using bilateral contracts, short-term and spot market purchases, but without using short term or spot market purchases for needed capacity.

ESPs have conservatively not procured resources to serve this very uncertain load. However, what makes the load-resource tables "unbalanced" for at least one company is that a matching supply resource was not listed in the categories on the form for bilateral contracts, generic renewable capacity, generic non-renewable capacity, or short-term/spot market purchases. It becomes apparent that future bilateral contracts and spot market purchases will likely provide most of the capacity (and energy) needed to projected demand.

At least one ESP gave no indication regarding plans for adding to its portfolio of supply resources.

This fall, the CPUC is expected to adopt resource adequacy requirements covering the period June 2006 onwards. If these requirements match D.04-10-035 and the Phase II workshop Report discussion, then at least some ESPs will be required to modify their strategies and to acquire qualifying resources that cover both expected monthly peak loads and the minimum 15 percent planning reserve margin.

Energy Requirements

For 2006, these five companies estimate their collective annual retail energy demand will be 15,134 GWh. This is an estimate of the "most likely" case, including the peak demand for likely new customers, plus the expected demand of current customers who renew or extend their direct access contracts. Collectively, energy requirements are estimated to be 14,068 GWh in 2010 and 16,353 GWh in 2016. The trend is shown on Figure 5-7.

For most ESPs, the month with largest amount of energy use is consistently July or August. Total amounts of energy delivered to at least one company to its retail customers are fairly consistent from month to month. For this ESP, energy demand peaks in August, but this amount is typically just 16 percent larger than energy use in February when monthly energy consumption ebbs.

Two companies forecast growth in customer energy requirements. At least one company forecast a general downward trend in monthly energy demand, no doubt reflecting the contract expiration dates of its existing customer base. One company forecast flat-line energy use by its retail customers for the entire forecast period, meaning that each August had the same high figures, and each December had the same low figures, etc.

Renewable Resources

The amounts of energy supplied under contracts from renewable energy sources are estimated to grow from 293 GWh in 2006, to 649 GWh in 2009, to 738 GWh in 2010, and 1,446 GWh in 2016. These amounts are shown on Figure 5-9 and Figure 5-10.

Only one company submitted a Resource Plan indicating that it was on a path to deliver 20 percent of its retail energy requirements from state-defined eligible renewable resources by 2017. For this company, renewable energy supplies will comprise 12 percent of retail sales requirements in 2009, and 19 percent in 2016.

At least two companies do not anticipate signing any contracts for renewable energy delivery during the forecast period. Nor do these companies anticipate adding generic renewable resources to the portfolio of supply contracts. On the capacity and energy tables, no data was provided on the rows related to renewable supplies. They may anticipate purchasing renewable energy on spot markets, or meeting their renewable energy obligations by purchasing renewable energy credits (RECs). However, the supply forms and instructions did not specifically ask for this type of data, and the companies did not identify these options as part of their compliance strategy.

Uncertainties of Concern to ESPs

One company warns that because its customers are free to leave, it is difficult to make long term projections of demand. From its narrative:

> "Unlike the IOUs, energy service providers … do not have captive customers. Direct Access (DA) qualified customers can choose service from any ESP or can choose to return to bundled utility service. Accordingly, the largest uncertainties for ___ are whether its current customers remain ___, whether its current customers choose another ESP, whether it's current customers choose to return to bundled service from the IOU's, and whether ___ can entice customers of other ESPs to switch from their current provider(s) to ___."

One ESP warns of other uncertainties related to serving Direct Access (DA) customers:

> "The wholesale cost of power is another significant uncertainty over which ___ has no control and no ability to influence. As wholesale power costs increase, the costs that DA customers must pay also increase. When the DA CRS of $27 per MWh is added to the wholesale power costs, some customers may choose to return to bundled service by the applicable IOU."
>
> "Another major uncertainty for … all ESPs is regulatory uncertainty. California has proven itself an extremely unstable market with constant change. Anti-free market forces continue to try to regulate or legislate DA out of existence. In addition to frontal assaults on DA, opponents of a free market are constantly trying to undermine DA by adding economic, regulatory or administrative burdens on DA customers and providers."
>
> "As a result of regulatory uncertainty in the past, many customers have been unwilling to enter into long-term power purchase transactions, even when wholesale power prices were extremely favorable. This may continue to be an issue in the future as well."

One company is mostly concerned with uncertainty regarding the wholesale market. From its narrative:

> "The number one driver of uncertainty for ___ is the wholesale power market; specifically the forward curve for energy delivered into SP-15 and NP-15. This uncertainty far-and-away surpasses the regulatory environment…. Unfortunately, ___ has no ability to control the cost of energy as we procure from the wholesale markets. At some point, if the wholesale market prices continue to rise, as they have over the

> past two years, the economics of Direct Access will reverse and most, if not all of ___ load, will migrate to a lower cost supplier.”

Regulatory uncertainty is one of the top concerns for most ESPs. From one company’s narrative:

> “The second greatest uncertainty for ___ is the regulatory and political environment. This ESP plans and procures energy as demand warrants, we have no assured book of business beyond our contracting window, therefore, ___ has no generating resources under contract beyond that window. Thus, the costs associated with resource adequacy requirements that, through regulation, extend beyond our contracting horizon are costs that ___ incurs with no offsetting counterparty under contract.”

One company is also concerned about stranded costs and exits fees that slow the momentum for moving toward opening direct assess. From its narrative:

> “The third greatest uncertainty is the regulatory lag that exists. The UDC's cost structure and recovery of costs is lagged, in some cases, by years via the 3-year rate case cycle and yearly ERRA proceedings. In addition, the ever-changing DWR revenue requirements and associated “true ups” continues to inject varying degrees of uncertainty over the economics of direct access. The re-payment of the DA-CRS and its eventual withering away is estimated in some scenarios as only a few years out and in other scenarios over a decade out. This kind of uncertainty is but one factor that influences the duration of the term of retail contracts and biases them toward the shorter end of the spectrum.”

One company is mostly concerned with legislative and regulatory uncertainty. From its narrative:

> “The greatest uncertainties an ESP in California faces that can affect its portfolio in near and far range forecasting are varied but predominately come from the legislative and regulatory venues. These are only exceeded by the risk of unintended consequences. The market and competitor behaviors are uncertain but do not have the same level of impact. That is an extremely strong statement given the volatility in the North American energy complex today.”

Near the top of its list are concerns regarding TURN’s so-called “re-regulation ballot initiative”, which would permanently eliminate new direct access. Long-term planning is made more difficult by uncertainties about stranded core/non-core expenses, and potential acceleration of the 20 percent renewable energy goal to 2010.

One company is not optimistic regarding the proposed policy of requiring load serving entities to procure their own reserves. Here is an excerpt:

> <u>Resource Adequacy</u>
>
> The final outcome of this regulatory requirement will most likely affect our forecast in three ways. First, if enacted as discussed currently it will effectively destroy the seven-year-old operating reserves market the ISO has run. This will in turn eliminate the transparency of this element of the market. The interface between the capacity and energy markets in the real time from a financial to system operations perspective will become unavailable to market participants as well as policy makers.
>
> The second way our business forecast will be affected is in our inability to manage our portfolio as all western portfolios have been managed for decades with respect to the short term markets. The short term market optimization brought about from physical fundamental knowledge and experience which sets us apart from other market participants will be negated. The only purchasing activity within the operating month will be done by generators due to forced outages. The generators will of course have built this risk premium into every MWh they sell forward thereby significantly increasing the financial expense for no gain to the market. If a specific customer or our portfolio consumption changes dramatically eight months before the summer season we are forced into being in a long position by regulatory compliance in a market that is biased towards lower spot prices.
>
> Or for a more spontaneous example customer ABC decides to pull its third shift for next month which reduces its consumption by thirty percent and now the ESP has power to sell into a falling market. The amount of these types of exposure with no guaranteed rate of return as the UDC enjoys becomes a very real constraint for the business and its future forecast.
>
> The third impact on our business forecast is in the area of product innovation which is the core of bringing value to the customer base beyond the plain vanilla aggregate service the UDC is designed to provide. Our customer's have grown to appreciate and expect their ability to call and co-design their future rates with us incorporating layering of risk and term lengths to suit their specific businesses. The currently discussed capacity showings will take away the customers' flexibility other than on an annual basis. The sensitivity on this issue will be around synthetic products requiring significant risk allocations."

One company is concerned that various proposed legislative bills would significantly impact their business. This company specifically mentioned Assembly Bill 1704 which would lift the direct access suspension, and AB 1585 which would accelerate the state's Renewable Portfolio Standards for ESPs to 2010. Two other examples of uncertainty of concern are potential new regulatory requirements related to resource adequacy for ESPs, and the implementation of exit fees for non-core departing load. All these uncertainties and more affect the ability to forecast and serve customer load in California.

One company is mostly concerned with regulatory uncertainty regarding the potential for full restoration direct access. From its narrative:

> "As an ESP ____ faces a variety of uncertainties that affects its load forecasts. The dominant forms of uncertainty Strategic Energy faces in California are related to Regulatory Uncertainty."

For this company, regulatory uncertainty includes:

- Implementation of a core/non-core market structure
- Structure of adopted core/non-core market
- Legislative or initiative based re-regulation of the direct access market
- Involvement in Community Choice Aggregation
- Changes to UDC switching rules
- Market Pricing
- DA CRS reassessment
- Current Direct Access Load Growth Opportunities
- Resource Adequacy Requirements
- Renewable Portfolio Standards
- Direct Access Cost Responsibility Surcharge ("DA CRS")"

Like other ESPs, this company has other concerns regarding legislative and regulatory uncertainty. Among the topics listed from its narrative are:

- Community Choice Aggregation,
- Changing rules that affect the ability of Unbundled Non-Core customers to return to IOUs, ESPs,
- Market Pricing,
- Direct Access exit fees,
- Resource Adequacy Rules imposed on ESPs, and
- Renewable Portfolio Standard rules imposed on ESPs.

APPENDIX C: RECENT RETAIL PRICES IN CALIFORNIA AND WESTERN U.S. STATES

Statewide Prices

	1998	1999	2000	2001	2002	2003	2004	2005
AZ	7.33	7.23	7.25	7.35	7.21	7.34	7.59	7.11
CA	8.93	8.97	9.47	12.04	12.50	11.62	11.18	10.73
CO	5.95	5.95	5.88	5.57	6.00	6.77	7.00	7.29
ID	4.03	4.00	4.17	5.18	5.58	5.22	4.97	4.94
MT	4.79	4.96	5.00	6.26	5.75	6.16	6.09	6.24
NM	6.78	6.58	6.58	7.02	6.73	7.00	7.19	7.13
NV	5.76	5.93	6.17	7.88	8.42	8.29	8.58	8.58
OR	4.90	4.86	4.89	4.97	6.32	6.18	6.09	6.29
UT	5.16	4.86	4.84	6.31	5.39	5.41	5.72	5.40
WY	4.31	4.30	4.34	5.23	4.68	4.76	4.95	4.92

Residential

	1998	1999	2000	2001	2002	2003	2004	2005
AZ	8.68	8.53	8.44	8.30	8.27	8.35	8.47	7.90
CA	10.59	10.68	10.89	12.65	12.90	12.00	11.78	11.75
CO	7.45	7.38	7.31	7.46	7.37	8.14	8.32	8.72
ID	5.28	5.26	5.39	6.03	6.59	6.24	6.08	5.88
MT	6.50	6.78	6.49	6.83	7.23	7.56	7.84	7.43
NM	8.85	8.62	8.36	8.65	8.50	8.69	8.78	8.70
NV	7.00	7.13	7.28	9.07	9.43	9.02	9.70	10.09
OR	5.83	5.75	5.88	6.31	7.12	7.06	7.12	7.17
UT	6.84	6.27	6.29	7.06	6.79	6.90	7.24	7.07
WY	6.28	6.34	6.50	6.96	6.97	7.04	7.10	6.87

Commercial

	1998	1999	2000	2001	2002	2003	2004	2005
AZ	7.76	7.51	7.34	7.36	7.28	7.09	7.50	7.01
CA	9.49	9.79	10.25	12.76	13.22	12.19	11.90	11.11
CO	5.67	5.61	5.55	5.67	5.67	6.60	6.92	7.25
ID	4.34	4.20	4.24	4.94	5.71	5.56	5.34	5.20
MT	5.87	6.35	5.60	6.17	6.53	7.10	7.17	7.08
NM	7.80	7.53	7.06	7.47	7.22	7.36	7.52	7.57
NV	6.50	6.66	6.74	8.44	9.06	8.79	9.10	9.34
OR	5.04	4.94	5.06	5.40	6.59	6.38	6.39	6.64
UT	5.71	5.29	5.23	6.48	5.60	5.59	5.92	5.65
WY	5.25	5.28	5.29	5.49	5.71	5.74	6.00	5.96

Industrial

	1998	1999	2000	2001	2002	2003	2004	2005
AZ	5.12	5.04	5.27	5.30	5.20	5.38	5.50	5.39
CA	6.49	6.57	7.14	9.89	10.83	9.85	8.53	8.00
CO	4.34	4.38	4.25	4.50	4.52	5.10	5.32	5.29
ID	2.92	2.90	3.11	4.56	4.34	4.16	3.83	3.47
MT	3.26	3.14	3.97	4.77	3.70	4.01	4.14	4.31
NM	4.47	4.25	4.69	4.91	4.48	4.95	5.10	5.08
NV	4.57	4.77	4.98	6.57	7.25	7.30	7.25	6.84
OR	3.60	3.58	3.56	3.59	4.72	4.63	4.25	4.24
UT	3.45	3.36	3.35	4.89	3.84	3.79	4.07	3.82
WY	3.38	3.34	3.36	3.88	3.55	3.65	3.90	3.80

Source: DOE-EIA

APPENDIX D: CALIFORNIA RETAIL PRICE OUTLOOK

Consolidated Retail Electricity Price Forecast --- Nominal Cents/kWh

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
PG&E	Residential	12.4	12.7	12.3	12.1	12.0	12.1	12.1	12.0	12.2	12.0	12.3	12.3
	Commercial	13.6	13.9	13.7	13.7	13.9	14.0	13.8	13.6	13.8	13.6	13.7	13.7
	Industrial	9.9	10.1	10.1	10.1	10.3	10.4	10.3	10.0	10.2	10.0	10.2	10.3
	Agricultural	11.2	11.9	11.3	11.3	11.7	11.8	11.8	11.7	11.9	11.7	12.0	12.0
	Other	12.5	12.6	12.6	12.6	13.0	13.2	13.2	13.1	13.3	13.2	13.5	13.6
SCE	Residential	12.5	12.6	13.1	13.5	12.7	12.8	12.9	12.9	12.5	12.6	12.7	12.9
	Commercial	14.2	15.3	15.7	16.2	15.8	15.8	16.0	16.2	16.4	16.5	16.6	16.7
	Industrial	9.8	10.6	11.3	11.5	11.4	11.4	11.5	11.6	11.5	11.6	11.6	11.7
	Agricultural	9.4	9.4	9.9	10.1	10.1	10.1	10.1	9.9	9.4	9.5	9.6	9.6
	Other	14.9	14.3	14.7	15.5	15.6	15.8	16.1	16.0	15.5	15.6	15.9	16.1
SDG&E	Residential	16.2	16.7	16.7	17.0	16.4	16.6	16.9	17.3	17.6	17.9	18.2	18.5
	Commercial	13.3	13.6	13.6	13.8	13.6	13.8	14.0	14.2	14.4	14.6	14.8	15.0
	Industrial	11.2	11.5	11.5	11.8	11.9	12.1	12.4	12.6	12.8	13.0	13.2	13.5
	Agricultural	15.3	15.8	15.8	16.1	16.3	16.6	16.9	17.2	17.5	17.8	18.1	18.4
	Other	15.5	15.4	16.0	16.3	16.6	16.8	17.1	17.5	17.8	18.1	18.4	18.7
BGP	Residential	12.5	12.7	13.0	13.1	13.3	13.2	13.4	13.5	13.6	13.8	13.9	14.1
	Commercial	12.5	12.6	12.9	13.1	13.2	13.1	13.3	13.5	13.6	13.8	14.0	14.1
	Industrial	10.0	10.1	10.4	10.5	10.5	10.6	10.7	10.8	10.9	11.0	11.1	11.2
	Agricultural	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SMUD	Residential	9.0	10.5	10.8	10.8	10.1	9.9	10.1	10.3	10.4	10.5	10.7	10.9
	Commercial	9.1	10.7	10.9	11.0	10.2	10.1	10.3	10.4	10.5	10.7	10.8	11.0
	Industrial	7.2	8.5	8.7	8.8	8.1	8.0	8.2	8.3	8.4	8.5	8.6	8.8
	Agricultural	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LADWP	Residential	10.4	10.4	10.6	10.8	10.9	11.0	11.2	11.4	11.5	11.7	11.8	12.0
	Commercial	9.6	9.1	9.1	9.3	9.3	9.3	9.4	9.5	9.5	9.6	9.7	9.7
	Industrial	7.4	6.8	6.9	6.9	7.0	6.9	6.9	7.0	7.0	7.0	7.0	7.1
	Agricultural	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other IID	Residential	11.4	11.6	11.8	12.0	12.2	12.5	12.7	12.9	13.1	13.4	13.6	13.8
	Commercial	11.1	11.3	11.5	11.7	11.9	12.1	12.3	12.6	12.8	13.0	13.2	13.5
	Industrial	9.3	9.4	9.6	9.8	10.0	10.2	10.3	10.5	10.7	10.9	11.1	11.3
	Agricultural	9.8	9.9	10.2	10.3	10.5	10.7	10.9	11.1	11.3	11.5	11.7	11.9
	Other	14.2	14.4	14.7	15.0	15.2	15.5	15.8	16.1	16.4	16.6	16.9	17.2

Source : CEC staff
Notes: This outlook of electricity rates consolidates IOU, Municipal and energy service provider (ESP) rates into rates by service territory.
BGP: Burbank, Glendale and Pasadena

APPENDIX E: GENERATION AND T&D COST OUTLOOK BY IOU RATE CLASS

PG&E

	Total			Residential			Small Commercial			Medium Commercial			Industrial		
	Generation	T&D	Total	Generation	T&D	Total	Generation	T&D	Total	Generation	T&D	Total	Generation	T&D	Total
2005	5.4	6.7	12.2	4.5	8.4	12.9	6.3	8.8	15.1	8.1	6.3	14.4	7.4	5.5	12.9
2006	6.1	5.7	11.8	5.1	7.3	12.4	7.1	7.7	14.9	9.1	5.1	14.2	8.4	4.5	12.9
2007	6.1	5.5	11.5	5.1	7.0	12.1	7.2	7.4	14.6	9.1	5.0	14.2	8.4	4.4	12.9
2008	6.2	5.3	11.4	5.4	6.7	12.0	7.5	7.1	14.6	9.5	5.1	14.6	8.8	4.5	13.3
2009	6.2	5.5	11.7	5.3	6.8	12.2	7.4	7.3	14.7	9.5	5.2	14.7	8.7	4.6	13.4
2010	6.0	5.6	11.6	5.1	7.0	12.1	7.2	7.4	14.6	9.1	5.3	14.5	8.4	4.7	13.1
2011	5.7	5.8	11.5	4.9	7.1	12.0	6.8	7.6	14.4	8.6	5.5	14.1	8.0	4.8	12.8
2012	5.8	5.9	11.8	4.9	7.3	12.2	6.8	7.8	14.6	8.7	5.6	14.3	8.0	4.9	12.9
2013	5.9	5.7	11.7	4.9	7.0	12.0	6.9	7.5	14.4	8.8	5.3	14.0	8.1	4.6	12.7
2014	6.1	5.9	11.9	5.0	7.2	12.2	7.0	7.7	14.7	9.0	5.4	14.4	8.3	4.7	13.0
2015	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2016	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

SCE

	Total			Residential			Small Commercial			Medium Commercial			Industrial		
	Generation	T&D	Total	Generation	T&D	Total	Generation	T&D	Total	Generation	T&D	Total	Generation	T&D	Total
2005	7.8	5.0	12.8	6.2	6.4	12.6	8.2	7.6	15.7	10.0	4.4	14.4	8.7	3.3	12.0
2006	8.4	5.1	13.6	6.6	6.5	13.1	8.8	7.7	16.5	10.9	4.6	15.4	9.4	3.4	12.8
2007	8.5	5.5	13.9	6.6	7.0	13.6	8.8	8.2	17.0	10.9	4.9	15.8	9.4	3.7	13.1
2008	8.3	5.2	13.5	6.4	6.3	12.8	8.6	7.6	16.2	10.7	5.0	15.7	9.2	3.8	13.0
2009	8.2	5.4	13.5	6.4	6.5	12.8	8.5	7.7	16.2	10.6	5.1	15.7	9.1	3.8	12.9
2010	8.2	5.5	13.7	6.4	6.6	13.0	8.6	7.9	16.4	10.6	5.2	15.8	9.1	3.9	13.0
2011	8.1	5.6	13.7	6.1	6.8	12.9	8.5	8.1	16.6	10.8	5.4	16.1	9.1	4.0	13.2
2012	7.9	5.7	13.6	5.6	6.9	12.5	8.3	8.3	16.5	10.9	5.5	16.4	9.0	4.1	13.1
2013	7.9	5.8	13.7	5.6	7.0	12.6	8.3	8.4	16.7	10.9	5.6	16.5	9.0	4.2	13.2
2014	7.9	5.9	13.8	5.6	7.2	12.7	8.3	8.6	16.9	10.9	5.7	16.6	9.0	4.2	13.3
2015	7.9	6.1	13.9	5.5	7.3	12.9	8.3	8.8	17.0	10.9	5.8	16.7	9.0	4.3	13.3
2016	7.9	6.2	14.1	5.6	7.5	13.1	8.3	9.0	17.3	10.9	6.0	16.9	9.1	4.4	13.5

SDG&E

	Total			Residential			Small Commercial			Medium and Large Comr		
	Generation	T&D	Total	Generation	T&D	Total	Generation	T&D	Total	Generation	T&D	Total
2005	6.1	7.7	13.8	7.4	9.0	16.4	7.4	9.5	16.9	4.9	6.4	11.3
2006	6.1	7.4	13.5	7.4	8.7	16.1	7.4	9.1	16.5	4.9	6.2	11.1
2007	6.1	7.4	13.5	7.4	8.7	16.1	7.4	9.1	16.5	4.9	6.2	11.1
2008	6.1	7.0	13.1	7.4	7.8	15.2	7.4	8.2	15.6	4.9	6.2	11.1
2009	6.1	7.0	13.1	7.4	7.8	15.2	7.4	8.2	15.6	4.9	6.2	11.1
2010	6.1	7.0	13.1	7.4	7.8	15.2	7.4	8.2	15.6	4.9	6.2	11.1
2011	6.1	7.0	13.1	7.4	7.8	15.2	7.4	8.2	15.6	4.9	6.2	11.1
2012	6.1	7.0	13.1	7.4	7.8	15.2	7.4	8.2	15.6	4.9	6.2	11.1
2013	6.1	7.0	13.1	7.4	7.8	15.2	7.4	8.2	15.6	4.9	6.2	11.1
2014	6.1	7.0	13.1	7.4	7.8	15.2	7.4	8.2	15.6	4.9	6.2	11.1
2015	6.1	7.0	13.1	7.4	7.8	15.2	7.4	8.2	15.6	4.9	6.2	11.1
2016	6.1	7.0	13.1	7.4	7.8	15.2	7.4	8.2	15.6	4.9	6.2	11.1

[i] Charles Gus, Integrated Resource Planner, City of Anaheim, Electricity Resource and Bulk Transmission Data Submittal to the California Energy Commission, April 1, 2005

[ii] Email from Himanshu Pandey to Jim Woodward, July 11, 2005.

[iii] Personal communication from Himanshu Pandey, Burbank, to Jim Woodward, California Energy Commission, July 11, 2005.