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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Sacramento Natural Gas Storage, LLC, for a Certificate of Public Convenience and Necessity for Construction and Operation of Gas Storage Facilities and Requests for Related Determinations	))))))	Application No. 07-04-013 (Filed April 9, 2007)

AVONDALE GLEN ELDER NEIGHBORHOOD ASSOCIATION'S REQUEST FOR OFFICIAL NOTICE

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For: Avondale Glen Elder Neighborhood Association

Dated: August 27, 2010

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Pursuant to California Public Utilities Commission Rule of Practice (hereinafter CPUC Rule) 13.9, Avondale Glen Elder Neighborhood Association (hereinafter AGENA) requests that Administrative Law Judge Richard Smith and Assigned Commissioner Timothy Alan Simon take official notice of the following facts:

1. Pages 9 to 11 and A-49 to A-53 of the November 2009 California Energy Commission staff report *An Assessment of Resource Adequacy and Resource Plans of Publicly Owned Utilities in California* (CEC-200-2009-019) (hereinafter "Staff Report"). The Staff Report is available for download at http://www.energy.ca.gov/2009 publications/CEC-200-2009-019/CEC-200-2009-019.PDF. The Staff Report discusses the Sacramento Municipal Utilities District's (hereinafter SMUD) resource capacity and energy supplies from pages A-49 to A-53 and also discusses SMUD in the section entitled "Resources Adequacy Loads and Resources for Larger Publically Owned Utilities, 2008-2009" from pages 9 to 11. Sacramento Natural Gas Storage (hereinafter

SNGS) requested Official Notice of only pages A-50 and A-52 of this report.[1] SNGS' Request for Official Notice omits the entire context of the Staff Report's discussion about SMUD. The full report is relevant because it demonstrates that (1) SMUD's 2009 peak load decreased because of demand response, efficiency and conservation, (2) SMUD has not yet needed to utilize its demand side response measures, (3) between 2010 and 2018 SMUD's reliance on natural gas to meet the Firm Peak-Hour Requirement will decrease by one percent, and (4) SMUD's renewable energy capacity will double from 2010 to 2018. (See, e.g., Staff Report at pp. 9-10, A-49.) Official Notice of all sections of the Staff Report discussing SMUD is necessary to allow for a complete discussion and understanding of the Staff Report's conclusions about SMUD and the tables of which SNGS' requests Official Notice.[2] The title page of the Staff Report, pages 9 to 11, and pages A-49 to A-53 are attached hereto as Exhibit A.

2. Pages 131 to 144 of the December 2009 California Energy Commission 2009 Integrated Energy Policy Report (CEC-100-2009-003-CMF) (hereinafter "2009 IEPR"). The 2009 IEPR is available for download at

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[1] / To the extent that SNGS' Request for Official Notice can be read as inclusive of the entire Staff Report, only pages A-50 and A-52 were attached and therefore only those pages would be included in the record of this proceeding. However, all of the relevant pages of the Staff Report should be included in the record. Therefore, this request should be granted even if SNGS' Request includes the entire Staff Report.

[2] / AGENA assumes for purposes of this Request that SNGS' Request for Official Notice might be granted. If SNGS' Request for Official Notice is denied, then AGENA acknowledges this request is moot. Such a ruling would mean that all of the items in both SNGS' Request and this Request must be submitted as evidence in order to be considered in this proceeding (as AGENA has requested and has previously done) instead of as requests for official notice.

http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF. SNGS requested Official Notice of only pages 136 and 140 of the 2009 IEPR.[3] However, the 2009 IEPR discusses natural gas from pages 131 to 144. SNGS' Request for Official Notice omits the entire context of the 2009 IEPR discussion of natural gas. Read in its entirety, the 2009 IEPR is relevant because it demonstrates that (1) new extraction methods will increase overall natural gas supply in California, (2) by 2018 natural gas demand in California is projected to be eight percent (8%) lower than forecasted in 2007, (3) development of additional pipelines have increased supply, improved utilities' natural gas receiving ability, and increased flexibility to choose different supply sources, and (4) for a variety of reasons the price of natural gas in California is among the lowest in the nation and California is comparatively well-shielded from price volatility. (*See, e.g.,* 2009 IEPR, pp. 134, 139, 140-141, 144.) Official Notice of 2009 IEPR's full chapter on natural gas is necessary to allow for a complete discussion and understanding of the conclusions in the 2009 IEP and of the sections SNGS selectively included in its Request for Official Notice. The title page and pages 131 to 144 of the 2009 IEPR are attached hereto as Exhibit B.

3. The Official Statement of SMUD, approved at SMUD's July 13, 2010 Board meeting, that if the SNGS Project were not constructed, "the District would consider ***other available*** storage options." (Official Statement at p. 27 [emphasis added].)

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[3] / To the extent that SNGS' Request for Official Notice can be read as inclusive of the entire 2009 IEPR, only pages 136 and 140 were attached and therefore only those pages would be included in the record of this proceeding. However, all of the relevant pages of the Staff Report should be included in the record. Therefore, this request should be granted even if SNGS' Request includes the entire 2009 IEPR.

The Official Statement also demonstrates that SMUD, based on its own most recent assessment, projects a lower planned peak requirement through 2019 than prior reports produced by either SMUD or CEC. (Official Statement at p. 33.) The Official Statement may be downloaded from the Municipal Securities Rulemaking Board's (MSRB) website, MSRB was established by Congress under the 1975 amendments to the Securities Exchange Act of 1934, and the Official Statement can be accessed at http://emma.msrb.org/EA393164-EA308929-EA704612.pdf. This statement is relevant because it shows that SMUD does not need the proposed project. The cover page, pages 14-36, and page 69 of the Official Statement are attached hereto as Exhibit C.

4. The Executive Summary of the SMUD 2009 Ten-Year Transmission Plan Assessment, dated November 17, 2009. This document is relevant because it is SMUD's conclusion, based on its own comprehensive assessment, that SMUD can reliably meet the NERC/WECC maximum load reliability standards in both the near term (2010 through 2014) and the long term (2015 through 2019). This responds directly to claims made by SNGS based on reports of which it requests official notice. (*See* Response of SNGS to Motion by AGENA for Reconsideration of the Scope of Supplemental Hearings at p.4.) The title page and pages I - V of the SMUD 2009 Ten-Year Transmission Plan Assessment are attached as Attachment 1 to the Declaration of Colin Bailey in Support of this Request for Official Notice which is attached to this Request as Exhibit D.

CPUC Rule 13.9 allows official notice of documents to the same extent as allowed in California courts. California Evidence Code Section 452, the governing rule in California courts, authorizes judicial notice of official acts of legislative, executive and

judicial departments. California Evidence Code Section 453 states that judicial notice of any matter specified in Evidence Code Section 452 "shall" be taken if a party requests it and: "(a) Gives each adverse party sufficient notice of the request, through pleadings or otherwise, to enable such adverse party to prepare to meet the request; and (b) Furnishes the court with sufficient information to enable it to take judicial notice of the matter."

The fact of publication of official California Energy Commission and SMUD reports and the contents of those reports are proper subjects of official notice.[4] AGENA therefore requests that official notice of the matters set forth herein and attached hereto be taken.

Dated: August 27, 2010

Respectfully submitted,

LEGAL SERVICES OF NORTHERN CALIFORNIA

By: /s/
STEPHEN E. GOLDBERG

For: Avondale Glen Elder Neighborhood Association

[4] / In accordance with SNGS' Opposition to AGENA's Motion to Strike, AGENA requests official notice of the fact of publication and the fact that relevant agencies reached the conclusions contained in the reports for which official notice is requested, but not of the truth of the facts contained in the reports. (Response of SNGS to AGENA Motion to Strike at p.4.) Given that SNGS made this clarification to its request for official notice, this request for official notice is particularly important because statements in the reports, without considering whether they are factually true, can only be evaluated given their complete context.

Exhibit A

CALIFORNIA
ENERGY
COMMISSION

AN ASSESSMENT OF RESOURCE ADEQUACY AND RESOURCE PLANS OF PUBLICLY OWNED UTILITIES IN CALIFORNIA

STAFF REPORT

November 2009
CEC-200-2009-019

Arnold Schwarzenegger, *Governor*

Resource Adequacy Loads and Resources for Larger POUs, 2008–2009

As shown in **Table 1**, the 15 largest POUs, which have annual peak loads larger than 200 MW, account for 95 percent of all POU peak loads in the state. In 2008, LADWP and SMUD provided 57 percent of peak power needs for all public power customers in California. For 2009, the sum of forecast peak loads for all 40 POUs is 15,462 MW as shown in **Table 1.** This amount includes end-use customer demand plus any firm sales obligations, but does not include a PRM. Adding a 15 percent PRM to 2009 peak loads would raise total resource need to 17,781 MW.

Table 1: Peak Load and Annual Energy Requirements for the 15 Largest POUs, 2008 and 2009

15 POUs with Peak Loads Larger than 200 MW	2008 Peak MW	2009 Peak MW [1]	2008 Energy GWh	2009 Energy GWh
LADWP	6,006	5,690	28,230	27,908
SMUD	3,086	2,826	11,718	11,647
Imperial ID	979	938	3,736	3,716
Modesto ID	650	689	2,692	2,810
Turlock ID	602	558	3,336	2,344
Anaheim	581	524	2,700	2,792
Riverside	535	590	2,669	2,546
NCPA	501	495	2,678	2,621
Silicon Valley Power	490	477	3,005	3,035
Roseville Electric [2]	338	411	1,307	1,684
Glendale	306	335	1,239	1,126
Pasadena	310	316	1,245	1,275
Burbank	289	304	1,247	1,248
Redding	273	287	1,017	1,022
Vernon	204	189	1,121	1,092
Sub-total for the largest 15 POUs	15,150	14,629	67,940	66,866
Total for all 40 POUs	15,952	15,462	71,983	71,028
Largest 15 as a % of all 40 POUs	95%	95%	94%	94%

1 The 2009 Peak MW equals peak-hour demand for end-use customers plus firm sales, but does not include the planning reserve margin

2 The forecast increases for Roseville include a new firm sales obligation of 75 MW and 328 GWh, expiring in 2011.

Source: California Energy Commission, POU resource plan and resource adequacy filings, Spring 2009

Forecasted 2009 peak loads were down 905 MW from actual 2008 peak loads. Some of this apparent reduced demand is attributable to 333 MW in demand response/ interruptible programs available in 2009, none of which were called upon in 2008. Energy efficiency and conservation programs are also helping to reduce peak demand that utilities must serve. However, the largest factor for reduced 2009 peak demand in load forecasts is that current economic conditions are worse than in 2008.

LADWP forecasts 2009 adjusted peak demand at 5,690 MW, equal to a 316 MW reduction from 6,006 MW actual peak demand in 2008. But this 2009 forecast peak demand is only 207 MW less that LADWP's 1-in-2 forecast for 2008 at 5,897 MW. With no net increases in demand-side resources, this 207 MW reduction in forecast peak demand for 2009 can be attributed to reduced economic activity during the current recession, which would equal a reduction of 3 percent.

For 2009, SMUD has an adjusted peak-hour demand forecast of 2,826 MW, which includes 200 MW of demand response/interruptible programs and 29 MW of new energy efficiency programs; SMUD's 2008 actual peak-hour demand reached 3,086 MW without calling on those demand-side resources. This comports with the Energy Commission demand forecast for SMUD showing a 2 percent reduction from 2008 to 2009 in the weather-normalized 1-in-2 peak demand.

Meeting Peak Load Requirements with Utility-Owned Capacity Additions Since 2001

Since 2001, California POUs have brought 3,014 MW online (**Table 2**). Collectively, POUs invested in 2,450 MW of new thermal generation, including 510 MW in 2007-2008. **Table 2** shows 559 MW (nameplate) of new renewable resources since 2001, but this does not include numerous small projects, especially landfill gas, that each added less than 10 MW.

Table 2: POU Capacity Additions Greater Than 10 MW Since 2001

POU	Facility	MW	Online Date	Technology
LADWP	Harbor 10-14	235	Jan-02	Combustion Turbine
Redding	Redding Power 1-4	40	Jun-02	Combustion Turbine
Burbank	Lake 1	47	Jul-02	Combustion Turbine
Riverside	Springs	44	Jun-02	Combustion Turbine
Modesto ID	Woodland	80	Jun-03	Combined-Cycle
Colton	Augua Mansa Peaker	43	Jul-03	Combustion Turbine
Pasadena	Glenarm 3 & 4[1]	20	Oct-03	Combustion Turbine
LADWP	Solar DG facilities	17	Jan-04	Solar
Glendale	Grayson Unit 9[2]	6	Mar-04	Combustion Turbine
LADWP	Valley 6-7-8 (net)[3]	49	May-04	Combined-Cycle
LADWP	Haynes 3 & 4[4]	49	Jan-05	Combined-Cycle
Corona	Clearwater Cogen	30	Feb-05	Combined-Cycle
SVP	Von Rasefeld	147	Mar-05	Combined-Cycle
Burbank, *et al*[5]	Magnolia	328	Sep-05	Combined-Cycle
Vernon	Malburg	134	Oct-05	Combined-Cycle
SMUD	Cosumnes 1	500	Mar-06	Combined-Cycle
LADWP	Pleasant Valley	82	May-06	Wind
Modesto ID	Ripon	95	Jun-06	Combined-Cycle
Riverside	Riverside Energy Center	98	Jun-06	Combustion Turbine
SMUD	Solano Phase 1	39	Jun-06	Wind
Roseville	Roseville Energy Park	160	Oct-07	Combined-Cycle
Turlock ID	Walnut	250	Feb-08	Combined-Cycle
Imperial ID	Niland GT	100	Jun-08	Combustion Turbine
LADWP	Castaic upgrades	30	Jul-08	Hydro
SMUD	Solano Phase 2	62	Apr-08	Wind
LADWP	Willow Creek	72	Dec-08	Wind
Turlock ID	Windy Point	137	May-09	Wind
LADWP	Pine Tree	120	Jun-09	Wind
	Total Nameplate MW	3,014		

[1]Net increase, 94 MW project resulted in retirement of Broadway Units 1 & 2.

[2]Net increase, 45 MW project resulted in retiring another Grayson Unit.

[3]Net increase, 501 MW (dependable) project resulted in retiring 4 other Valley Units.

[4]Net increase, 560 MW (dependable) project resulted in retiring 2 other Haynes Units.

[5]Burbank, Anaheim, Glendale, Pasadena, Cerritos, and Colton own shares in Magnolia.

Source: California Energy Commission, Electricity Analysis Office, September 2009

Roseville Electric	2010[a]	2018[a]
	-4%	17%
Total	**1,687**	**1,484**
	100%	**97%**
Scheduled Additions		
None	*0*	*0*
Total Scheduled Additions	***0***	***0***
	0%	***0%***

Notes:

a. All energy values are in GWh. Each percentage value is of the Firm Energy Requirement for that category.

1. The S-1 form has two WAPA line items, but the Energy Balance Resource Accounting Table Form S-2 has only one line for WAPA.

2. The Capacity Resources Accounting Table Form S-1 lists this line item as Renewable Supply Contracts.

Source: Roseville Electric Energy Balance Resource Accounting Table Form S-2, January 31, 2009, updated May 5, 2009

Sacramento Municipal Utility District

Capacity

The Firm Peak-Hour Requirement for the Sacramento Municipal Utility District's (SMUD) increases four percent from 3,129 MW in 2010 to 3,269 MW in 2018. Total generation capacity decreases slightly during these years from 2,680 MW to 2,672 MW. SMUD adds 525 and 250 MW of short-term and spot market purchases in these two years, bringing total existing plus planned capacities to 3,205 and 3,922 MW in 2010 and 2018, respectively. SMUD has a residual resource need of 347 MW in 2018, and sufficient time exists for SMUD to acquire the capacity needed.

SMUD's UEG resources do not include either coal or nuclear. Its UEG capacity requirements are met by natural gas-fired, hydroelectric and renewable resources. The natural gas-fired category remains unchanged in capacity from 2010 to 2018, resulting in a very small 1 percent decrease between 2010 and 2018in this category's contribution toward meeting the Firm Peak-Hour Requirement.

Both hydroelectric and renewable UEG resources show increases between 2010 and 2018, with the former increasing by 390 MW, or 57 percent. This increases the hydroelectric category's contribution toward meeting the Firm Peak-Hour Requirement from 22 to 33 percent. The renewable category doubles in dependable capacity between 2010 and 2018 because the Solano wind project adds 46 dependable MW (105 MW nominal) in 2011. This increase, combined with the PV capacity of 1 MW, increases this UEG category's share of meeting the Firm Peak-Hour Requirement capacity by about 2 percent.

Long-term contracts provide 23 percent of the contribution to the Firm Peak-Hour Requirement in 2010 and 15 percent in 2018. Of 2010's long-term contracts, 243 MW will end

before 2018, a reduction in capacity of 43 percent. Short-term contracts total 230 MW in 2010, being nine percent of the capacity obtained. However, the reduction in the short-term category share towards meeting the Firm Peak-Hour Requirement is only 7 percent.

The Solano wind project is the only scheduled addition from 2010 to 2018.

Table A-23: SMUD Capacity Resources in 2010 and 2018

Sacramento Municipal Utility District	**2010[a]**	**2018[a]**
Firm Peak-Hour Requirement[1]	**3,129**	**3,269**
Percent Change		**4%**
Utility Electric Generation (UEG)		
Coal-fired Plants		
None	*0*	*0*
Total Coal-fired Plants	0	0
	0%	0%
Nuclear Power Plants		
None	*0*	*0*
Total Nuclear Plants	0	0
	0%	0%
Gas-fired Power Plants		
Campbell Soup	*161*	*161*
Carson Ice	*93*	*93*
Cosumnes	*501*	*501*
McClellan	*72*	*72*
Proctor & Gamble	*180*	*180*
Total Gas-fired Plants	1,007	1,007
	32%	31%
Hydroelectric Power Plants		
All utility-controlled Hydro Plants	*684*	*1,074*
Total Hydroelectric Power Plants	684	1,074
	22%	33%
Renewable Power		
Solano (wind) (45 MW in 2010, increases to 91 MW in 2011)	*45*	*91*
Solar PV (utility scale)	*1*	*1*
Total UEG Renewable	46	92
	1%	3%
Total of Utility Electric Generation	***1,737***	***2,173***
	56%	***66%***
Long-Term Renewable and Other Bilateral Contracts (LT)		
Various Renewable & Small Hydro Resources	*51*	*51*
Western Area Power Administration (WAPA)	*409*	*438*
UC Davis Medical Center	*10*	*10*
PP&L (ends in 2015)	*100*	*0*
East Bay MUD 1 & 2 (ends in 2015)	*22*	*0*
PPM Wind (ends in 2015)	*31*	*0*
Avista Biomass & Hydro (ends in 2015)	*75*	*0*
SPI Biomass (ends in 2017)	*15*	*0*

Sacramento Municipal Utility District	2010[a]	2018[a]
Total LT Contracts	713	499
	23%	15%
Subtotal (UEG + LT)	***2,450***	***2,672***
	78%	***82%***
Short-Term to Expiration Contracts (ST)		
Klamath Falls (ends in 2011)	*50*	*0*
PPM Iberdrola Renewables (portfolio) (ends in 2011)	*50*	*0*
Klamath Falls Peaking (ends in 2013)	*30*	*0*
PPM Iberdrola Renewables (gas/option) (ends in 2013)	*100*	*0*
Total ST Contracts	230	0
	7%	0%
Total (UEG + LT +ST)	**2,680**	**2,672**
	86%	**82%**
Short-Term and Spot Market Purchases (ST/SM)	*525*	*250*
Total ST Contracts	525	250
	17%	8%
Total	**3,205**	**2,922**
	102%	**89%**
Scheduled Additions		
Solano (wind) (45 MW in 2010, increases to 91 MW in 2011)	*45*	*91*
Total Scheduled Additions	***45***	***91***
	1%	***3%***

Notes:

a. All capacity values are in MW. Percentages are of the Firm Peak-Hour Requirement for each category.

1. SMUD's Line 14 entry incorporates a 15 percent PRM.

Source: SMUD Capacity Resource Accounting Table Form S-1, March 3, 2009

Energy

From 2010 to 2018, SMUD's Firm Energy Requirement increases 3 percent from 11,583 GWh to 11,396 GWh. Total energy supplies from existing and planned resources decrease from 12,011 GWh to 10,154 GWh. The percentage of the Firm Energy Requirement that can be met by existing and specifically planned resources is 104 percent in 2010 and 85 percent in 2018.

SMUD's UEG resources do not include coal or nuclear. Most of SMUD's energy requirements are met by UEG natural gas-fired, hydroelectric, and renewable resources. The natural gas-fired category provides more than one-half of SMUD's Firm Energy Requirement, and approximately three-quarters of the UEG resources each year, remaining almost unchanged in total GWh from 2010 to 2018.

Hydroelectric UEG resources, under median hydrological conditions, will supply about 14 percent of the Firm Energy Requirement throughout the planning horizon. However, in dry 2007, SMUD's hydropower plants produced only 1,054 GWh, equal to 9 percent of that

year's energy requirements. In drier 2008, SMUD's hydropower system produced 885 GWh, equal to 7.5 percent of that year's energy needs.

UEG renewable energy is expected to increase nearly three-fold between 2010 and 2018. Almost all of the increase in UEG renewable energy is attributable to Solano wind project additions in 2011. Nonetheless, UEG renewable resources at most make up less than 10 percent of either the Firm Energy Requirement or the UEG resources.

Electricity deliveries from existing long-term contracts will decline as these contracts expire. These existing renewable and non-renewable contractual supplies are counted on for 3,220 GWh in 2010 and 1,454 GWh in 2018. Two long-term contract line items in the table above show no change supply contributions. They are various renewable and hydroelectric resources, and a contract with the Western Area Power Administration.

Table A-24: SMUD Energy Supplies in 2010 and 2018

Sacramento Municipal Utility District	**2010[a]**	**2018[a]**
Firm Peak-Hour Requirement	**11,583**	**11,936**
Percent Change		**3%**
Utility Electric Generation (UEG)		
Coal-fired Plants		
None	*0*	*0*
Total Coal-fired Plants	0	0
	0%	0%
Nuclear Power Plants		
None	*0*	*0*
Total Nuclear Plants	0	0
	0%	0%
Gas-fired Power Plants		
Campbell Soup	*1,122*	*1,122*
Carson Ice	*398*	*434*
Cosumnes	*4,006*	*4,006*
McClellan	*2*	*2*
Proctor & Gamble	*879*	*869*
Total Gas-fired Plants	6,407	6,433
	55%	54%
Hydroelectric Power Plants		
All utility-controlled Hydro Plants	*1,610*	*1,594*
Total Hydroelectric	1,610	1,594
	14%	13%
Renewable Energy Resources		
Solano wind (45 MW in 2010, increases to 91 MW in 2011)	*281*	*670*
Solar PV (utility scale)	*3*	*3*
Total UEG Renewable	284	673
	2%	6%
Total of Utility Electric Generation	***8,301***	***8,700***
	72%	***73%***
Long-Term Renewable and Other Bilateral Contracts (LT)		

Sacramento Municipal Utility District	2010[a]	2018[a]
Various Renewable & Small Hydro Resources	*517*	*517*
Western Power Administration (WAPA)	*937*	*937*
UC Davis Medical Center	*0*	*0*
PP&L (ends in 2015)	*569*	*0*
East Bay MUD 1 & 2 (ends in 2015)	*185*	*0*
PPM Wind (ends in 2015)	*224*	*0*
Avista Biomass & Hydro (ends in 2015)	*657*	*0*
SPI Biomass (ends in 2017)	*131*	*0*
Total LT Contracts	3,220	1,454
	28%	12%
Subtotal (UEG + LT)	***11,521***	***10,154***
	99%	***85%***
Short-Term to Expiration Contracts (ST)		
Klamath Falls (ends in 2011)	*219*	*0*
PPM Iberdrola Renewables (portfolio) (ends in 2011)	*230*	*0*
Klamath Falls Peaking (ends in 2013)	*9*	*0*
PPM Iberdrola Renewables (gas/option) (ends in 2013)	*32*	*0*
Total ST Contracts	490	0
	4%	0%
Total (UEG + LT +ST)	**12,011**	**10,154**
	104%	**85%**
Short-Term and Spot Market Purchases (ST/SM)	*0*	*0*
Total ST Contracts	0	0
	0%	0%
Total	**12,011**	**10,154**
	104%	**85%**
Scheduled Additions		
Solano wind (45 MW in 2010, increases to 91 MW in 2011)	*281*	*670*
Total Scheduled Additions	***281***	***670***
	2%	***6%***

Notes:

a. All energy values are in GWh. Each percentage value is of the Firm Energy Requirement for that category.

Source: SMUD Energy Balance Resource Accounting Table Form S-2, March 3, 2009

Silicon Valley Power

Capacity

For the City of Santa Clara, doing business as Silicon Valley Power (SVP), the Firm Peak-Hour Requirement increases by 11 percent from 555 MW in 2010 to 617 MW in 2018. Existing and planned resources (not including 75 MW of short-term and spot market purchases) represent 122 percent of the 2010 Firm Peak Requirement, and 118 percent of the 2018 requirement. When planned short-term and spot market purchases are included, the

Exhibit B

CALIFORNIA ENERGY COMMISSION

2009 INTEGRATED ENERGY POLICY REPORT

CEC-100-2009-003-CMF

ARNOLD SCHWARZENEGGER
GOVERNOR

within an Energy Commission-designated corridor. The Energy Commission believes that FERC should allow an IOU to qualify for cost recovery if the land is set aside for one or more transmission projects that may be constructed 10–15 years in the future and is within an Energy Commission-designated corridor.

Natural Gas

Natural gas provides almost one-third of the state's total energy requirements and continues to be a major fuel in California's supply portfolio. Natural gas is used in electricity generation, space heating for homes and commercial buildings, cooking, water heating, industrial processes, and as a transportation fuel.

Natural Gas Supplies

California's supply of natural gas comes from four areas: in-state production, southwestern United States, the Rocky Mountain region, and Canada, with 87 percent of the state's natural gas coming from out-of-state sources. After nearly a decade of relatively flat or declining U.S. natural gas production, domestic production in the lower 48 states began rising in 2006, and by 2008 returned to levels last seen in 1974 (Figure 13).[178]

Twenty years ago, California produced 20 percent of the state's supply of natural gas, the Southwest provided nearly 60 percent, and the rest came from Canada and other basins. However, in-state natural gas production has been declining over time (Figure 14), and the downward trend may continue from the current 825 million cubic feet per day (MMcf/d) to possibly 700 MMcf/d by 2020.

Production from conventional natural gas basins that provided the majority of domestic supply began to decline in the late 1990s and early 2000s, but as natural gas prices have increased, so have exploration and production. There have also been advances in horizontal drilling, a more efficient and cost-effective method for recovery of domestic unconventional natural gas reserves that provides the potential for greater gas production per well. Finding and development costs of a typical vertical well average $1.71 per thousand cubic feet (Mcf), while costs for a horizontal well average between $1.06/Mcf and $1.34/Mcf.[179]

Natural gas from out-of-state is delivered into California using the interstate natural gas pipeline system. Five interstate pipelines bring gas to California: Gas Transmission-Northwest pipeline carries Canadian natural gas; El Paso, Transwestern, and Questar's Southern Trails transport gas from the Southwest; and the Kern River pipeline system moves Rocky Mountain production to market. Except for Southern Trails, each of these pipelines serves other customers before reaching California. Figure 15 shows natural gas pipelines and resource areas in western North America.

Interstate pipelines and California production currently have the capacity to supply California consumers up to 10,230 MMcf/d. However, because of upstream demand and utility multiple receiving points, the state can only rely on receiving 8,315 MMcf/d of supply from pipelines and native production. Simply because an interstate pipeline has a certain delivery capacity does not mean that all of its capacity is available to California. Each pipeline serving California has firm delivery

178 Domestic natural gas production was 21.60 trillion cubic feet (Tcf) in 1974 and 21.40 Tcf in 2008.

179 California Energy Commission, *Shale-Deposited Natural Gas: A Review of Potential*, May 2009, CEC-200-2009-005-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-005/CEC-200-2009-005-SD.PDF].

FIGURE 15: NATURAL GAS RESOURCE AREAS AND PIPELINES

Source: *2008 California Gas Report*

In Operation

1. El Paso Natural Gas
2. Gasoducto Bajanorte (GB)
3. Gas Transmission Northwest (GTN)
4. Kern River Pipeline
5. Mojave Pipeline
6. North Baja Pipeline
7. Northwest Pipeline
8. Paiute Pipeline
9. Pacific Gas Electric Company
10. Questar Southern Trail Pipeline
11. Rockies Express (REX)
12. San Diego Gas &Electric Company
13. Southern California Gas Company
14. Transportadora de Gas Natural (TGN)
15. TransCanada Pipeline
16. Transwestern Pipeline
17. Tuscarora Pipeline

Proposed

18. Bronco Pipeline
19. Ruby Pipeline
20. Kern River Expansion
21. Sunstone Pipeline

contracts not only for California customers but also for customers upstream from California. Because of these upstream commitments, not all of a pipeline's capacity is available for delivery to the state.

If demand exceeds reliable supply, utilities and noncore customers will still be able to meet demand up to the pipeline delivery capacity, but prices would increase dramatically. To meet their needs, California utilities and noncore customers would then have to purchase natural gas that otherwise would have been delivered to customers outside of California. To attract the supply, they would have to pay elevated prices that would drive California prices above current market levels and cost the state's consumers an unknown amount.

Once natural gas arrives in California, it is distributed by the natural gas utility companies. The three major utilities – Southern California Gas Company (SoCal Gas), SDG&E, and PG&E – collectively serve 98 percent of the state's natural gas customers. The remaining 2 percent are served by municipal and smaller or out-of-state utilities.

The amount of available natural gas storage is also important. PG&E's storage fields have the ability to cycle small quantities of gas through the year. The utility needs most of the injection period to fill its storage to meet winter demand. PG&E has indicated that it may maintain a 1,451 MMcf/d withdrawal rate through the winter. Although SoCal Gas has good natural gas cycling capabilities, the independent, nonutility Lodi and Wild Goose facilities have better cycling abilities. Each may withdraw and inject several times throughout the year and may also hold the same delivery levels as volumes of gas in storage are extracted. SoCal Gas asserts that it can maintain up to 2,225 MMcf/d[180] of gas withdrawals throughout all levels of storage.

A potential additional source of natural gas supply is liquefied natural gas (LNG). In the near future, California could receive natural gas from an LNG facility located at Costa Azul, Mexico. The construction of the Costa Azul LNG terminal was completed last year and still awaits the first of its commercial deliveries. LNG is available, but suppliers at the moment are reluctant to enter the lower-priced Pacific Coast market. When supply does start to flow, North Baja Mexico will have first choice to receive up to 300 MMcf/d to meet its industrial and power plant needs. Any excess in supply would add to California's supply mix. Under normal conditions, this would lead to price competition for market share. However, LNG is a price taker, meaning it does not set the price; with the reluctance for deliveries to the Pacific Coast, it is unclear what impact Costa Azul will have on supply and price.

Another option for new supplies of natural gas is shale gas.[181] Natural gas accumulates in three types of formations: limestone, sandstone, and shale. Before 1998, limestone and sandstone formations produced nearly all domestic supplies of natural gas. Exploration and production companies, however, have long known about the potential for natural gas in shale formations. This potential led the industry to pursue the engineering innovations needed to access these natural gas resources.

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180 *2008 California Gas Report,* p. 90, available at: [http://www.socalgas.com/regulatory/documents/cgr/2008_CGR.pdf].

181 California Energy Commission, *Shale-Deposited Natural Gas: A Review of Potential*, draft staff paper, May 2009, CEC-200-2009-005-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-005/CEC-200-2009-005-SD.PDF].

In the mid-1990s, shale-deposited natural gas provided about 1 percent of production in the lower 48 states.[182] The development of three-dimensional and four-dimensional seismic surveys, improved drilling technologies, and technological innovations in well completion and stimulation has increased the productivity of wells drilled into shale formations so that by mid-2008, shale production represented almost 10 percent of production from the lower 48 states (Figure 16). The Natural Gas Supply Association believes that production from the shales "…could double in the next 10 years and provide one-quarter of the nation's natural gas supply."[183]

Natural Gas Demand

As a state, California is the second largest natural gas consumer in the United States, representing more than 10 percent of national natural gas consumption.[184] Customers in the residential and commercial sectors, referred to as "core" customers, accounted for 29 percent of the state's natural gas demand in 2008. Large consumers such as electricity generators and the industrial sector, referred to as "noncore" customers, accounted for about 71 percent of demand in the same year. California remains heavily dependent on natural gas to generate electricity, which accounted for more than 40 percent of natural gas demand in 2008.[185]

Most of the natural gas used in the residential sector is for space and water heating. Since 1970, the number of households in California has almost doubled, which has increased overall natural gas consumption, but as a result of California's building and appliance efficiency standards, the average amount of natural gas consumed per household has dropped more than 36 percent.

In 2009, the Energy Commission staff prepared a comprehensive forecast of natural gas demand by end users (excluding electricity generation) as part of the *2009 IEPR*.[186] Table 6 compares the 2009 natural gas forecast with the 2007 forecast for selected years.

The 2009 staff forecast is lower in the near term (2010) because of current economic conditions and because actual consumption in 2008, the starting point for the 2009 forecast, was lower than the forecasted 2008 consumption that was used in the 2007 forecast. By 2018, consumption is expected to be about 8 percent lower than in the prior forecast. As the economy recovers, projected annual growth in natural gas consumption is expected to exceed California Energy Demand 2007 forecast growth for 2010–2018.

Although the method to estimate energy efficiency impacts has been refined, the staff draft forecast uses essentially the same methods as earlier long-term staff demand forecasts. A more detailed discussion of forecast

182 "Lower 48"excludes Alaska and Hawaii.

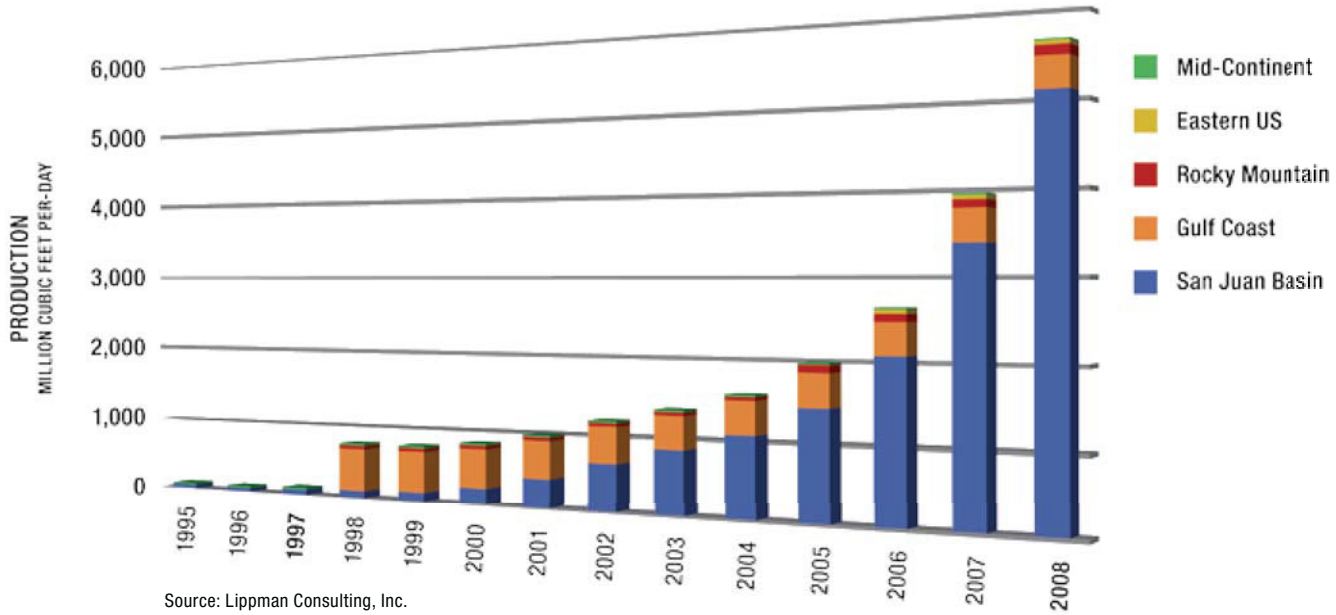
183 Natural Gas Supply Association, News Release, October 8, 2008, "Natural Gas from Shale Could Double in Next Ten Years," available at: [http://www.ngsa.org/newsletter/pdfs/2008%20Press%20Releases/22%20-%20Natural%20Gas%20from%20Shale%20to%20Double%20w%20graphic.pdf].

184 Energy Information Administration, *Natural Gas Annual 2007*, available at: [http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/natural_gas_annual/current/pdf/table_002.pdf].

185 Southern California Gas Company, *2008 California Gas Report*, available at: [http://www.socalgas.com/regulatory/documents/cgr/2008_CGR.pdf].

186 California Energy Commission, *California Energy Demand 2010–2020 Adopted Forecast*, December 2009, CEC-200-2009-012-CMF, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF].

FIGURE 16: LOWER 48 SHALE NATURAL GAS PRODUCTION



Source: Lippman Consulting, Inc.

TABLE 6: STATEWIDE END-USER NATURAL GAS CONSUMPTION

	MM THERMS		
	CED 2007	CED 2009 (HIGH-RATE CASE)	PERCENT DIFFERENCE
1990	12,893*	12,893*	0.00%
2000	13,913*	13,913*	0.00%
2007	13,445	12,494*	-0.07%
2010	13,616	12,162	-10.68%
2018	14,058	12,894	-8.28%

* Historic Values

	ANNUAL AVERAGE GROWTH RATES	
1990–2000	0.76%	0.76%
2000–2008	-0.43%	-0.89%
2008–2010	0.63%	-1.34%
2010–2018	0.40%	0.73%

Source: California Energy Commission, 2009

methods and data sources is available in the *Energy Demand Forecast Methods Report*.[187]

Energy Commission staff also evaluated winter peak day natural gas demand trends and the effect of that demand on pipelines and natural gas storage, using demand data from the *2008 California Gas Report*[188] and from utility and pipeline filings made to the Energy Commission. Winter demand is driven primarily by heating requirements in the residential and commercial sectors, while natural gas for electricity generation represents about 14 percent of winter demand. Demand from the industrial sector has very little seasonal variation.

The state is shifting to renewable energy sources to provide a larger share of the electricity generated to meet California's needs. Unless they are paired with on-site energy storage technologies, certain renewable generation technologies are not dispatchable to follow load and may not be available to meet peak day requirements. Solar thermal and photovoltaic generation better match load than does wind generation. To ensure reliable service during peak demand periods, natural gas-fired generation will be needed to meet peaking requirements, provide load following and backup services for the renewable generation, and provide baseload services.

The type of natural gas unit needed to supplement renewable generation will affect the need for natural gas. While older units have heat rates in excess of 10,000 British thermal units (Btu) per kWh, the newer combined cycle facilities are more efficient and operate at approximately 7,500 Btu per kWh. A 40 percent loss of renewable generation would be equivalent to an increase of 480 MMcf/d in combined cycle fuel use. However, peaking units are less efficient and, depending on the age of the unit, will use 50 to 100 percent more gas per megawatt-hour (MWh) than a new combined cycle unit. Replacing renewable generation with a peaker plant would therefore increase gas demand by 770 MMcf/d.[189]

Natural Gas and the Environment

The shift to a greater reliance on horizontal, rather than vertical, wells in shale formations elevates the issue of potential environmental impacts. While regulatory agencies and environmental groups highlighted these issues in the past, in the last 10 years the increased activities in shale formations brought greater focus on the potential environmental impacts, which can occur in any of five areas: surface preparation, drilling and completion, production and clean-up, transmission and distribution, and consumption. As a result, the increased development and production of natural gas in shale formations has raised four primary environmental concerns: surface disturbance, GHG emissions, other air contamination, and potential leakage of chemicals into the groundwater.

Surface preparation before drilling any natural gas well can create environmental stress in sensitive areas. The potential impact on wildlife habitat and wilderness areas has led to moratoriums on natural gas drilling in the Rocky Mountains and other sensitive areas of the lower 48 states. Drilling operations can also have significant impacts, and some states, including New York and Pennsylvania, have issued restoration requirement rules.

187 California Energy Commission, *Energy Demand Forecast Methods Report,* June 2005, CEC-400-2005-036, available at: [http://www.energy.ca.gov/2005publications/CEC-400-2005-036/CEC-400-2005-036.PDF].

188 *2008 California Gas Report*, see [http://www.socalgas.com/regulatory/documents/cgr/2008_CGR.pdf].

189 California Energy Commission, *Natural Gas Infrastructure*, May 2009, CEC-200-2009-004-SD, available at: [http://www.energy.ca.gov/2009publications/CEC-200-2009-004/CEC-200-2009-004-SD.PDF].

Because natural gas is made up mostly of methane (a GHG), small amounts of methane can sometimes leak into the atmosphere from wells, storage tanks, and pipelines. The Energy Information Administration says that methane emissions from all sources account for about 1 percent of total United States GHG emissions, but about 9 percent of the "greenhouse gas emissions based on global warming potential."[190]

The industry is attempting to address some of the environmental impacts of natural gas extraction by using smaller rigs that reduce surface disturbance. The use of horizontal and directional drilling allows producers greater flexibility about where drilling rigs are located.[191] The shift to horizontal drilling and away from vertical drilling can also lessen surface disturbance by requiring fewer wells to recover an equivalent amount of resource.

On a per million Btu (MMBtu) basis, total emissions from natural gas produced from shale formations differ little from those of natural gas from conventional sources. However, the carbon footprint of the horizontal wells used to extract shale gas far exceeds that of a typical vertical well since the drilling process, the completion process, and the production stimulation process (hydraulic fracturing) require more carbon-based fuels, more drilling mud, and more water. Further, running the required equipment and pumps produces more emissions.

Developing equivalent amounts of natural gas resources, though, requires two to three times more vertical wells than horizontal wells. For example, extracting 20,000 million cubic feet of natural gas may require up to 30 vertical wells but only 10 horizontal wells. The

190 An indicator of the carbon dioxide equivalent.

191 Natural Gas Supply Association, see [http://www.naturalgas.org].

natural gas industry uses both well types to reach potential natural gas resources located thousands of feet beneath the Earth's surface, but each horizontal well recovers more natural gas on average than a vertical well. As a result, the overall carbon footprint for the entire development of a shale formation may not differ from that of an equivalent-sized formation developed using vertical wells.

There are also environmental issues associated with the water used in shale gas extraction. The hydraulic fracturing process used to extract natural gas from shale formations uses hundreds of thousands of gallons of water treated with chemicals. In the development of an entire field, the amount of water injected into a shale formation could reach into the hundreds of millions of gallons. The volume of water used in the development of natural gas from shale formations raises other environmental concerns, including the consumption of large water quantities and recovered water disposal. Although field operators retrieve most of the injected water once the hydraulic fracturing is completed, a significant quantity of water and chemicals remain within the formation.

When development of shale formations occurs near major population centers, environmentalists, with concerns that potential leakage of chemicals used in the hydraulic fracturing process could pose a health and safety risk, are calling for stricter regulation. Some states have developed regulatory requirements for development of shale formations. For example, New York has issued regulations that include guidelines for the use and disposal of water, the protection of groundwater, and the use of chemicals.[192] Pennsylvania has also instituted rules governing the extraction of natural gas from shale formations, noting that, "… developing our energy resources cannot come at the expense of our environmental resources – our water, our land and our ecosystems."[193] In 2008, inspectors from the state's Department of Environmental Protection ordered the partial shutdown of two drilling sites after discovering violations of state regulations.[194]

Investigation into the environmental issues raised by natural gas exploration and production is an ongoing effort that will continue to be addressed by Energy Commission staff. Shale gas is only the latest addition to a portfolio of natural gas extraction technologies that the Energy Commission staff monitors. Staff will continue to monitor and report on developments in all forms of natural gas exploration and production.

Another natural gas supply source with potential environmental issues is LNG, which tends to contain higher-Btu-content hydrocarbons that have not been processed out, as is typically done with domestically produced natural gas. This can cause increased particulate emissions and has raised some health and environmental concerns about the use of LNG. However, there appears to be a growing consensus that the carbon footprint for LNG, on a life cycle basis, is smaller than that of coal-fired generation.[195]

192 Department of Environmental Conservation, New York State, *Final Scope for Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, February 2009*, available at: [http://www.dec.ny.gov/docs/materials_minerals_pdf/finalscope.pdf].

193 Kathleen McGinty, Secretary of Pennsylvania's Department of Environmental Protection, speaking at a department-sponsored summit, June 2008.

194 Environmental News Service, June 16, 2008.

195 Jamarillo, P., W. Griffin, and H. Matthew, "Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electric Generation," *Environmental Science and Technology,* 2007, Vol. 41, No. 17, 6290 and PACE (2009). Life Cycle Assessment of Greenhouse Gas Emissions from Liquified Natural Gas and Coal Fired Generation Scenarios: Assumptions and Results.

In the Energy Commission's report, *Potential Impacts of Climate Change on California's Energy Infrastructure and Identification of Adaptation Measures*, staff reported potential impacts of climate change on the natural gas infrastructure. It appears that sea level rise as a result of climate change will have little impact on natural gas availability since most of the supply comes from basins located in Alberta, the Rockies, and the southwestern United States. Also, potential new sources of shale gas are located in regions that cannot be affected by rising sea levels. However, climate change could cause changes in consumer energy demand based on temperature (for example, increased need for air conditioning because of warming trends) and could decrease hydroelectric production because of changes to precipitation patterns and snowpack. A major change in consumer demand and hydro availability could affect the general pattern of natural gas withdrawal from storage facilities. If utilities cannot keep up with traditional storage levels, consumers could be impacted by higher costs.

Reducing the environmental footprint of natural gas use in California should follow the loading order approach used in the state's electricity system. First and foremost is improving residential, commercial, and industrial energy efficiency, as well as the efficient use of natural gas as a transportation fuel, to reduce emissions associated with consumption of natural gas. An example of California's successful energy efficiency efforts are the previously mentioned statistics that the average California home consumed 120 Mcf of natural gas per year 40 years ago, but today consumes less than 50 Mcf per year. The second priority is to accelerate the adoption of clean alternatives to conventional natural gas resources, such as biogas for both the electricity and transportation sectors, as well as improved technologies. Finally, the performance and reliability of the natural gas system and infrastructure must be improved.

Natural Gas and Reliability

California's dependence on natural gas as an energy source requires the state to maintain a reliable natural gas delivery and storage infrastructure. Eighty-seven percent of California's natural gas supply is from out-of-state and delivered by pipelines that extend deep into Canada, the Rocky Mountains, and the U.S. Southwest production areas.

California needs adequate delivery pipelines and utility receiving capacity to ensure the state has supply to meet its needs at competitive prices. The consequences of inadequate natural gas infrastructure were particularly apparent during the 2000–2001 energy crisis. Interstate pipelines delivering natural gas to California were running at or near capacity for more than a year. The utilities' receiving, local transmission delivery systems, and storage operations were at their limits. Because there were no supply options available, California incurred natural gas costs that were double those paid in the years just prior to the crisis.

During and after the crisis, California increased its interstate pipeline delivery capacity, utilities improved their receiving ability, and the utility and independent storage owners enhanced their storage operations to meet future high-demand day conditions. These improvements have given California utilities the flexibility to choose supply sources in their day-to-day operations, which has forced production areas to compete for a share of the state's natural gas market.

There are concerns about whether increased natural gas demand for electricity generation in the Southwest will reduce the amount of natural gas available for California. Along El Paso's southern pipeline system,

more than 10,000 MW of natural-gas fired power plants have been built. If all of these plants ramp up at the same time to meet electricity demand, it could affect the ability of the pipeline to meet the natural gas demand for those plants, possibly leading to unstable natural gas supplies for California. Kern River pipeline also makes upstream deliveries in Utah and Nevada that effectively reduce its ability to deliver full capacity to California.

Natural gas storage is an important piece of California's natural gas infrastructure. Without it, the supply pipelines would have to increase in size to meet winter demand, leaving a huge investment standing idle during half of the year. Storage fields are basically depleted natural gas fields that have had injection and withdrawal wells already drilled and compression and processing equipment added to clean up extracted natural gas. Natural gas is withdrawn from storage during periods of high demand, such as in the winter for space heating and in the summer for power generation. Natural gas is injected into storage during the spring and fall when overall demand is low, making pipeline capacity available to bring in additional natural gas to fill the storage facilities.

California does have potential new sources of natural gas from an existing LNG import facility in Baja, Mexico, along with pipeline projects on the horizon. Three pipeline projects should significantly increase the flow of natural gas to the state:

- The Ruby Pipeline project is planning to deliver natural gas from Opal, Wyoming, to California at a rate of 1.2 billion cubic feet per day (Bcf/d). This pipeline is scheduled to be in service by 2011, and will deliver natural gas to Malin, Oregon.

- The Sunstone Pipeline plans to deliver 1.2 Bcf/d of natural gas from Opal, Wyoming to Stansfield, Oregon. This pipeline is

planned to be on-line in 2011 and could displace much natural gas in Oregon, thus freeing up supplies for California.

- The Kern River pipeline expansion project will increase delivery of natural gas from Wyoming to Southern California by 0.2 Bcf/d. The expansion of the existing pipeline is scheduled to be completed in 2010.

In the *2007 IEPR,* staff projected that as much as 20 percent of North American natural gas requirements might be met with LNG by 2017. However, United States LNG imports in 2008 were significantly lower than the amounts projected by Energy Commission staff and others, owing to a range of market developments, both global and domestic. In addition, United States and West Coast LNG terminal development appears to be slowing, and there is a new sense that the United States may not have to rely on LNG to make up previously projected supply deficits. The number of LNG facilities previously proposed for California has been reduced to two, only one of which has filed applications for building permits.

Natural gas is also used in the transportation sector in a broad range of applications, including personal vehicles, public transit, commercial vehicles, and freight movement. Natural gas vehicles may use compressed natural gas or LNG. The number of California on-road, light-duty vehicles powered by natural gas has increased since 2001 from 3,082 to 24,810 in 2008. While these numbers are small compared to the total vehicle population, increasing alternative transportation fuels to help meet the state's GHG reduction goals will require careful evaluation of the impacts on the natural gas supply system.

Natural Gas and the Economy

Wide and frequent swings in natural gas prices affect natural gas consumers, producers, and investors. Natural gas price volatility, measured as the magnitude and rate of changes in a commodity price over a given period, affects the national economy as a larger portion of gross domestic product is consumed by rising energy costs. As natural gas prices rise, they can have a negative impact on residential consumers by consuming more of a household's discretionary income. Consumers are also affected because volatility adds uncertainty in the electricity generation industry, which ultimately affects the price of electricity. Volatility also makes budgeting and cost management more difficult for commercial and industrial consumers that use significant amounts of natural gas in their operations. For natural gas producers, volatility contributes to the boom-bust cycle of drilling activity, ultimately affecting available natural gas supplies. Natural gas price volatility also affects the energy planning process because the added uncertainty in predicting market movements affects the ability to accurately forecast natural gas prices.

During 2008, natural gas spot prices – the price of natural gas for next-day delivery at a specific location – traded as high as $13.32 per Mcf and as low as $5.63/Mcf. The large price fluctuations in 2008 increased the focus on price volatility and its impacts on natural gas market participants. Factors that influence natural gas prices and price volatility include weather, supply and demand imbalances, infrastructure issues, unreliable data, regional and global economic conditions, speculative trading, and market manipulation.

The impacts of natural gas price changes vary for different consumers. For example, residential and small commercial core customer demand tends to be somewhat less affected by price swings. Demand by these customers is largely driven by heating needs during cold weather, and because core customers are often unaware of natural gas price changes until a monthly bill arrives in arrears, there is little opportunity for them to reduce consumption in response to price changes. In

addition, the rates that utilities charge these core customers are still subject to oversight by government agencies and are not subject to daily price changes.

However, longer term wholesale price changes do affect the retail rates these customers pay when utilities receive approval to adjust their natural gas tariff rates to reflect a change in costs. These increased prices negatively affect core customers, especially low-income households, resulting in more residential customers that are unable to pay their monthly bills, increasing the number of consumers that require assistance through programs such as the Low-Income Home Energy Assistance Program.

Industrial, or noncore, consumers of natural gas tend to be much more sensitive to price volatility. These consumers typically purchase large quantities of natural gas directly from the market and are immediately affected by changing prices, making budgeting and cost management more difficult. For example, nitrogen fertilizer manufacturers use significant amounts of natural gas, the cost of which can account for 90 percent of the total manufacturing costs. Price volatility can therefore have a dramatic impact on their manufacturing operations. Also, because industrial consumers often are large users of natural gas, significant changes in natural gas prices can influence many operational decisions. If prices become too high or are extremely volatile, industrial users might consider switching to a different fuel if possible or even shutting down their operations.

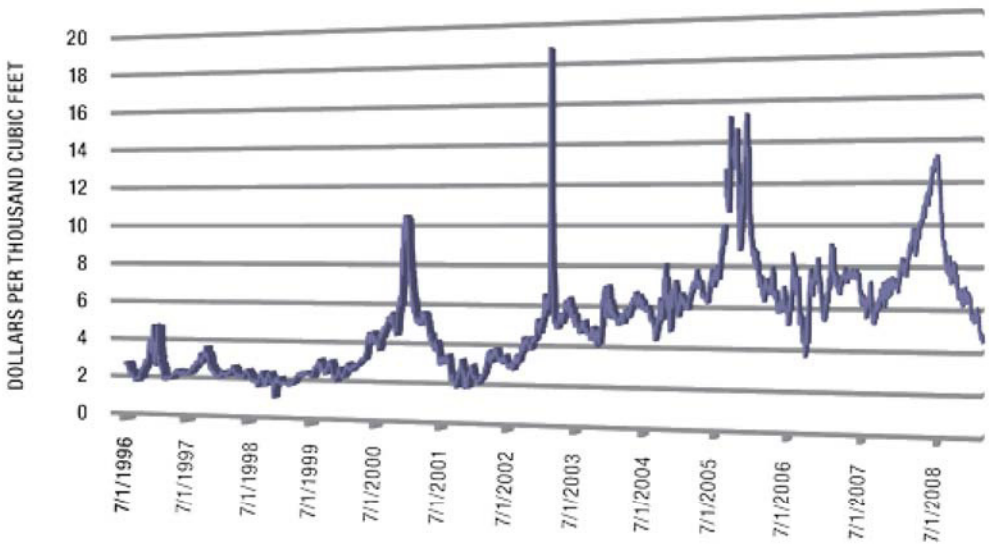
While price volatility can have material consequences for the industrial sector, some large industrial consumers have the ability to take advantage of hedging opportunities to reduce risk. Large users potentially could purchase and store natural gas when prices are low, enter into long-term fixed price contracts, or use financial instruments like options to lower the risk and uncertainty of changing prices.

The electricity generation sector is the largest consumer of natural gas, both nationally and in California,[196] so natural gas price volatility significantly affects this sector and ultimately the price of electricity. Natural gas price volatility leads to increased uncertainty for both regulated utilities and merchant power firms about the ongoing costs of operating natural gas-fired power plants, both existing and new. Increased uncertainty also heightens concern regarding investment in new natural gas-fired plants, which may be seen as more risky when compared to other generation technologies that use coal or renewable fuels.

Natural gas producers are also affected by price volatility, making project evaluation and investment decisions less certain. Price volatility can trigger concerns by lenders and investors and increase the cost of capital as lenders and investors demand greater returns because of increased uncertainty. Price volatility also contributes to recurring boom-bust production cycles and associated operational problems, such as employee turnover and expensive start-up and shutdown costs. The current period of falling natural gas prices provides a good example. Natural gas production is largely a capital intensive venture during well development but has lower marginal production costs once the well is producing gas. During periods of low prices, active wells can remain profitable to operate but, in the longer term, declining prices can lead to reduced production when the number of drilling rigs is reduced in response to sustained lower prices. Since prices peaked in July 2008,

196 Energy Information Administration, Natural Gas Consumption by End Use data, available at: [http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm].

FIGURE 17: HENRY HUB SPOT PRICES 1996–2008



Source: Natural Gas Intelligence data

United States drilling rig numbers dropped each week as prices continued to decline.[197]

Figure 17 shows a period of relatively stable natural gas prices in the late 1990s, followed by several periods of large price spikes after 2000. Henry Hub[198] spot prices traded within a $2/Mcf to $3/Mcf band throughout the late 1990s and early 2000s, rose to $4/Mcf, and surpassed $6/Mcf by the middle of the decade. One key factor that caused price increases was the growth in domestic demand that exceeded United States domestic production capabilities because North American basins were maturing and producing less gas. The combination of increasing domestic demand and declining domestic production resulted in natural gas prices moving higher.

There have been four major price spikes since 2000 that were caused by many of the physical and financial market factors mentioned earlier in this section. However, each price spike was influenced to different degrees by the various factors. For example, a severe cold winter storm played the significant role in the February 2003 price spike, and back-to-back hurricanes played the significant role in the fall 2005 price spike. The price spikes of winter 2000–2001 and summer 2008 were the result of a number of different factors, including market manipulation and market speculation.

197 Energy Information Administration's April 23, 2009, *Natural Gas Weekly* update reports that the domestic drilling rig count is down over 50 percent from its high in August 2008, reached in response to July 2008 peak prices.

198 Henry Hub is located in Louisiana and is North America's main natural gas trading hub and most widely quoted natural gas pricing point. It interconnects four intrastate and nine interstate pipelines that can transport enough natural gas to satisfy about 3 percent of total United States demand.

The flexibility from having extra infrastructure, coupled with supplies from lower-priced production areas, helps shield the state from the brunt of price volatility. Since California is part of an international natural gas market that includes Canada, the United States, and Mexico, a disruption in one area ripples though the rest of the market. California is not immune to the ripples, but the ripples are much smaller now when they reach the state. Prices of natural gas at California's border are among the lowest in the nation, with current prices considerably less than the Henry Hub price.

Fuels and Transportation

Although the fuels and transportation energy sector is responsible for producing the greatest volume of GHG emissions – nearly 40 percent of California's total – the issues confronting this sector go far beyond climate change. Reducing California's dependence on petroleum in general and foreign crude oil in particular are equally pressing issues. Doing so would not only reduce GHG emissions, but would also mitigate the effects that global demand, geopolitical events, crude oil refining capacity and outages, and petroleum infrastructure challenges have on fuel prices and the average cost of production of goods and services, both of which directly affect the state's economy and gross state product.

Assembly Bill 32 does not directly address GHG emissions reduction in the transportation sector, but legislation at both the state and federal level does. California's AB 1007 (Pavley, Chapter 371, Statutes of 2005), AB 118 (Núñez, Chapter 750, Statutes of 2007), AB 1493 (Pavley, Chapter 200, Statutes of 2002), California's Low Carbon Fuel Standard (LCFS), and the federal Energy Independence and Security Act's revisions to the Renewable Fuel Standard (RFS2) set policies and standards that will ultimately change vehicle and fuel technologies and accelerate the market for low carbon fuels well beyond the current level of demand.

The following section summarizes the Energy Commission's 2009 transportation supply and demand forecast. Providing this data will give decision makers a snapshot of the state's future fuel demand and supply for petroleum, as well as renewable and alternative fuels and vehicles. This data is imperative to understanding future fuel supply and infrastructure needs that could have a major impact on consumer reliability and the environment. In past *IEPR*s, the Energy Commission forecast has only included projections for petroleum transportation fuels. For the *2009 IEPR* cycle, staff expanded the list of transportation fuels to include demand forecasts for E85 (a blend of 15 percent gasoline and 85 percent ethanol), B20 (a blend of 80 percent diesel and 20 percent biodiesel), electricity, compressed natural gas (CNG), and LNG, with more limited analysis of hydrogen and propane.

Transportation Fuels Supply and Demand

In its transportation forecasts, the Energy Commission analyzes trends of transportation demand-related indicators, as well as demographic and economic variables. The transportation demand forecasts encompass four primary transportation sectors:

- Commercial and residential light-duty vehicles (under 10,000 pounds)
- Medium- and heavy-duty transit vehicles, including rail (over 10,000 pounds)

Exhibit C

OFFICIAL STATEMENT

RELATING TO

SACRAMENTO MUNICIPAL UTILITY DISTRICT

$250,000,000 ELECTRIC REVENUE BONDS, 2010 SERIES W

INTRODUCTION

This Official Statement, including the cover page and Appendices attached hereto, describes the Sacramento Municipal Utility District (the "District"), a political subdivision of the State of California (the "State"), and its $250,000,000 Electric Revenue Bonds, 2010 Series W (the "2010 Series W Bonds"), in connection with the sale by the District of the 2010 Series W Bonds. The 2010 Series W Bonds are being issued to (i) finance certain improvements and additions to the District's Electric System and (ii) pay costs associated with the issuance of the 2010 Series W Bonds.

The 2010 Series W Bonds are part of an Electric Revenue Bond authorization of the District and are issued pursuant to Resolution No. 6649 (the "Master Resolution") adopted in 1971, as amended and supplemented, and applicable California law, including Article 6a of Chapter 6 of the Municipal Utility District Act (Public Utilities Code Sections 12850 to 12860) (the "Act") and the Revenue Bond Law of 1941 (Government Code Section 54300 *et seq.*). The issuance of the 2010 Series W Bonds was authorized on July 13, 2010, by the Board of Directors of the District by a Fifty-Third Supplemental Resolution (the "Fifty-Third Supplemental Resolution") supplemental to the Master Resolution. The Master Resolution and all supplemental resolutions, including the Fifty-Third Supplemental Resolution, are collectively referred to herein as the "Resolution." See APPENDIX C - "SUMMARY OF CERTAIN PROVISIONS OF THE RESOLUTION."

The purchasers of the 2010 Series W Bonds, by virtue of their purchase of the 2010 Series W Bonds, will consent to certain amendments to the Resolution. See "SECURITY FOR THE BONDS – Consent to Amendments to the Resolution."

The 2010 Series W Bonds will be issued as bonds designated as "Build America Bonds" ("Build America Bonds") under the provisions of the American Recovery and Reinvestment Act of 2009, the interest on which is not excluded from gross income for purposes of federal income taxation. See "TAX MATTERS." The District expects to receive a cash subsidy payment from the United States Treasury equal to 35% of the interest payable on the 2010 Series W Bonds. Such cash subsidy payment may be offset against other liabilities of the District to the federal government or reduced or eliminated as described below. See "THE 2010 SERIES W BONDS – Designation of 2010 Series W Bonds as Build America Bonds."

The 2010 Series W Bonds and other bonds issued on a parity therewith pursuant to the Resolution are collectively referred to herein as the "Bonds." The Bonds, together with other Parity Bonds, are payable solely from the Net Revenues of the Electric System. See "SECURITY FOR THE BONDS." Bonds in the aggregate principal amount of $1,946,560,000 are outstanding as of June 1, 2010.

Although the Resolution establishes an "Electric Revenue Bond Reserve Fund" (the "Reserve Fund"), the Reserve Fund does *not* secure and will *not* be available to pay debt service on the 2010 Series W Bonds. The Reserve Fund secures all Bonds issued prior to January 1, 2004 that are currently

Controller. Cary Nethaway reports to the Chief Financial Officer. Mr. Nethaway is responsible for all District accounting and financial reporting. He was appointed as the Controller in 1993 and joined the District in 1979.

THE SERVICE AREA AND ELECTRIC SYSTEM

The Service Area

The District is the primary distributor of electric power within an area of approximately 900 square miles in central California. The service area includes the State capital, Sacramento, the populous areas principally to the northeast and south of the City of Sacramento (the "City" or "Sacramento") and the agricultural areas to the north and south. The City is located 85 miles northeast of San Francisco.

The District's electric system supplies power to a population of approximately 1.4 million with a total annual retail load of approximately 10,692 million kWh for the year ended December 31, 2009. As the capital of the nation's most populous state, Sacramento benefits from the stabilizing influence of a large government sector. Sacramento is home to the State government headquarters, the Sacramento County seat, the City government and various special districts that combine to make government the largest single employment sector in Sacramento. Construction, finance, insurance, real estate, transportation, communications, utilities and the service sector round out the major sectors of employment and industry in the Sacramento area.

The District's record peak load of 3,299 MW occurred on July 24, 2006. The District reviews its load forecast, at a minimum, on an annual basis.

The Electric System

The District owns and operates an integrated electric system that includes distribution, generation and transmission facilities.

The District supplies power to its bulk power substations through a 230 kilovolt ("kV") and 115 kV transmission system. This system transmits power from the District's generation plants, other than Solano Wind, and interconnects with Pacific Gas & Electric ("PG&E") and the Western Area Power Administration ("Western"). Power is distributed throughout Sacramento County via a 69 kV sub-transmission system with the exception of the City's downtown area which is served from the 115 kV transmission system. The downtown area is served from 115/12 kV and 115/21 kV substations. Inside the 21 kV systems are pockets of 4 kV distribution systems that are served from the 21 kV distribution system. The distribution system serving the remainder of the District's service territory is comprised of 69/12 kV substations with overhead and underground 12 kV distribution circuits.

BUSINESS STRATEGY

General

The District's Board of Directors has established the following purpose and vision statements: "The District's purpose is to provide solutions for meeting our customers' electrical energy needs. The District's vision is to empower our customers with solutions and options that increase energy efficiency, protect the environment, reduce global warming, and lower the cost to serve our region." The Board has adopted a set of strategic directives with related metrics, which it considers essential for the success of the District and for serving the District's customers. These include competitive rates, financial stability, reliability, customer relations, environmental leadership and safety.

The District's long-range business strategy focuses in part on ensuring financial stability by establishing rates that provide acceptable cash coverage of all fixed charges on a consolidated basis taking into consideration the impact of capital expenditures and other factors on cash flow. While the District's Board policy sets a minimum fixed charge of 1.3 times for annual budgets, the District's most recent rate increases, adopted by the District's Board in 2009, were intended to achieve a higher coverage level of 1.5 times by 2011. Due in large part to the effects of the current state of the economy on the District, it is not currently anticipated that such level will be achieved in 2011. The District's staff anticipates that the new revenue requirements and rate recommendation that it will develop later this year for 2012 will also be designed to provide coverage of 1.5 times by 2012. Over the past ten years the fixed charge ratio averaged 1.57 times.

The District's long-range business strategy also addresses legislative mandates concerning carbon emissions and renewable portfolio standards while insuring the continued reliability of electricity delivery to its customers. A significant consideration for the District will be how it will address its needle peak: those 40 or so hours of the year with extreme temperatures when customer demand surges by up to 400 additional MWs. Key elements of the District's strategy include:

- developing and maintaining a sustainable and reliable power supply to meet peak demand growth consistent with State mandates for renewable energy and reduced carbon emissions;

- working closely with customers to assist and incentivize them to more efficiently manage energy use, which will contribute to meeting greenhouse gas emission targets and manage needle peak demand requirements;

- managing price, volumetric and credit risks associated with energy and natural gas procurement; and

- attracting, developing, and retaining, an inclusive, skilled and involved workforce that reflects the District's community's values and is committed to achieving the District's mission.

Sustainable Power Supply

Maintaining a sustainable power supply focuses on efforts to research, promote and implement new renewable energy technologies and sources to meet the District's long-term commitment to reduced carbon emissions and reliable energy supply. The District defines a sustainable power supply as one that reduces its greenhouse gas emissions from the generation of electricity to 10% of its 1990 carbon dioxide emission levels by 2050, while assuring reliability of the electrical system; minimizing environmental impacts on land, habitat, water quality and air quality; and maintaining a competitive position relative to other California electricity providers.

Renewable Energy. The District has a target to increase the percentage of its energy coming from renewable sources to 23.6% by the year 2010 and up to 37% by 2020. The District supplied an estimated 22.3% of its energy from renewable sources in 2009, and is on-schedule to meet its 2010 goal. The District also currently has sufficient power supply commitments to fulfill its renewable sources policy to 2016. Additionally, by applying certain of its surplus renewable sources from years prior to 2016 to the years 2017 through 2020 the District has sufficient power supply commitments to fulfill its renewable sources policy to 2020. The District's renewable resources goals consist of both a Renewables Portfolio Standard ("RPS") and a voluntary green pricing program for customers called Greenergy. In addition to new sources, meeting these goals will require replacement of certain existing renewable

contracts which expire in future years. While the District anticipates it will meet its renewable resource goal primarily through purchase contracts with third parties, it continues to explore additional wind development, partnering options with other utilities on future projects and local development options. The District's resource forecast (see "POWER SUPPLY AND TRANSMISSION – Projected Resources" herein) accounts for future renewable resources as a component of "Uncommitted Purchases." The District will continue to evaluate other generation and transmission options to ensure system reliability as the market in California evolves.

The District expects that the State will implement Assembly Bill 32 ("AB 32") climate change emissions regulations before the federal government takes similar action, and that AB 32 will result in two types of rules: direct regulations and a market based cap and trade program. While it is too early in the California regulatory process to determine the specific structure of a cap and trade program, the District expects that direct regulations will include renewable energy supply (e.g., a RPS) and energy efficiency (e.g., minimum electricity demand reduction requirements) mandates. These mandates currently exist in California and the District expects that they likely will be strengthened out to 2020. California's current RPS, which applies to Investor-Owned Utilities ("IOUs"), is a 20% renewable energy supply requirement of retail sales for 2010. The premium paid for renewable energy, relative to other energy options, has been increasing, which could be a consideration in working toward the District's goal to supply 33% of its energy from renewable sources (not including the Greenergy program) in 2020. Additionally, a shortage of transmission capacity has limited the development of lower-cost renewable resources that lie far from population centers. See "DEVELOPMENTS IN THE ENERGY MARKETS – State Legislation – *Greenhouse Gas Emissions*."

Customer Commitments and State Greenhouse Gas Emission Targets

The District is working closely with its customers to meet the anticipated growth in the demand for electricity while balancing environmental and customer service goals.

Advanced Metering, Infrastructure and Rate Design. As a community organization, the District is dedicated to providing transparency and local participation to enable customers to easily and positively affect energy usage, energy cost, and contribution to climate change. In October 2009 the District was awarded a $127 million federal grant to underwrite 40% of the cost of advanced meters for the entire system, install "smart technology' on several distribution circuits, test dynamic rates, and install equipment to facilitate load management. The grant will assist the District in advancing state-of-the-art technology that will allow customers to manage energy use and give the District experience in integrating smart grid elements to improve reliability, reduce losses, and improve customer service through better, timelier information.

Energy Efficiency. To further assist customers in managing energy usage, the District offers an extensive array of energy efficiency programs and services including financial incentives, loans, energy audits and education. In addition, the District has partnered with local developers to incorporate energy efficient measures in new home construction. The District has set a goal of meeting nearly all new load requirements related to growth through 2017 with energy efficiency measures. This target exceeds levels that California's IOUs are required to meet. See "POWER SUPPLY AND TRANSMISSION – Projected Resources."

Electricity and Natural Gas

The District continues to utilize a comprehensive and integrated power and fuel supply strategy to acquire a reliable and diversified portfolio of electricity and natural gas to meet existing and future needs. This strategy includes a combination of both physical supply and financial hedging transactions. The

District's physical supply arrangements include ownership interest in natural gas reserves and ownership of power generating resources, as well as a diversified portfolio of power and fuel supply purchase contracts that range in duration, with a mixture of fixed and variable pricing terms.

With regard to the power purchase contracts, the District has entered into a series of contracts for the purchase of electricity to supply the portion of its resource needs not already provided for by owned resources. The District also actively manages its exposure on variable rate electricity supply agreements by entering into financial contracts to fix prices when warranted by economic conditions. See "POWER SUPPLY AND TRANSMISSION – Power Purchase Agreements."

With regard to fuel supply contracts, the District utilizes a similar strategy of employing financial contracts of various durations to hedge its variable rate fuel supply contracts. Through these contracts the District has fixed the price of most of its anticipated natural gas requirements through 2013. See "POWER SUPPLY AND TRANSMISSION – Fuel Supply–*Supply*."

In addition to hedging prices for its natural gas and electricity needs, the District utilizes weather hedges to help mitigate swings in net income caused by variation in precipitation levels. Payments received from these hedging contracts help to offset the cost of replacement power when the amount of energy generated from the District's hydroelectric facilities is reduced due to limited precipitation. Some of the hedging contracts also require payments from the District to counterparties when precipitation exceeds normal levels. While weather hedges will still be used to mitigate the financial impacts of extremely low precipitation, the District has implemented a pass through rate component to help protect against increased power supply costs in years where precipitation levels at District-owned hydroelectric facilities are low. The pass through rate component is expected to be both more effective and less costly than weather hedges in providing a stabilizing effect on net income despite varying hydro conditions. See "DISTRICT RATES AND CUSTOMER BASE – Rates and Charges."

The Current Economy and Market Conditions

The District has been impacted by the current state of the economy in a number of ways. With the downturn in the local economy the District has seen a sales decline of 3.5% from 2008 to 2010 as well as reduced investment returns. Net sales after the effect of energy efficiency programs and SB1 solar reductions are expected to remain flat through 2014. Declining natural gas prices have resulted in collateral calls from some of the District's gas contract counterparties. As of June 18, 2010, the District had posted $65.8 million in collateral comprised of letters of credit issued under a bank facility with a maximum amount of $50 million and cash in the amount of $15.8 million. Further decreases in natural gas prices would result in increased collateral posting by the District and such increases may be significant. Assuming no change in gas prices, the District's collateral posting requirements will decrease by approximately $26 million over the next six months. While the posting of collateral is not an expense for the District, it does temporarily encumber unrestricted cash balances and the letter of credit facility described above.

The District has taken a number of steps to address these circumstances. The District established an Enterprise Performance initiative in 2008 to review the effectiveness of District processes against industry best practices. Many of the findings are currently being implemented. The efficiencies from these initiatives along with the benefits from the advanced metering project are expected to save up to $20 million per year in operating costs. The District has also reduced its ongoing capital expenditure plan to reflect the much reduced need for new system capacity.

In addition, on June 16, 2009 the Board approved rate increases of 5.5% effective September 1, 2009; 5.5% effective March 1, 2010; and 2.25% effective January 1, 2011. The District's staff anticipates that new revenue requirements and a new rate recommendation for 2012 and 2013 will be developed in the fourth quarter of 2010.

DISTRICT RATES AND CUSTOMER BASE

Rates and Charges

The District has autonomous authority to establish the rates charged for all District services. Unlike IOUs and some other municipal utility systems, retail rate and revenue levels are not subject to review or regulation by any other governmental agencies, federal, State or local. Changes in such rates require formal action, after public hearing, by the Board of Directors. This District is not required by law to transfer any portion of its collections from customers to any local government.

On June 16, 2009, the Board approved rate increases of 5.5% effective September 1, 2009; 5.5% effective March 1, 2010; and 2.25% effective January 1, 2011. The increased revenue supports the District's efforts to maintain its commitment to remain competitive and to achieve targeted fixed charge ratios, while maintaining high standards of reliability and customer service.

Effective July 2008, the District implemented a pass through rate component to deal with variations in hydroelectric generation from the District's Upper American River Project (the "UARP") (see "POWER SUPPLY AND TRANSMISSION – Power Generation Facilities – Hydroelectric") called a Hydro Generation Adjustment ("HGA"). The HGA is designed to increase revenues in dry years when the District must buy power to replace hydroelectric generation and return money to customers in wet years when the District has more hydroelectric generation than expected. The District designated $30 million of the Rate Stabilization Fund balance to initially fund an HGA balancing account. Each year the District determines the impact of precipitation variances on hydroelectric generation from the UARP. When the precipitation variance results in a deficiency of hydroelectric generation from the UARP, transfers from the HGA balancing account will be made in an amount approximating the cost to the District of replacement power until the balance in the HGA balancing account is zero. When the precipitation variance results in a surplus of hydroelectric generation from the UARP, deposits will be made to the HGA balancing account in an amount approximating the positive impact to the District from the surplus hydroelectric generation until the balance in the HGA balancing account is equal to 5% of budgeted retail revenue (currently approximately $60 million). If the balance in the HGA balancing account is not sufficient to cover transfers that would otherwise be made in the event of a deficiency in hydroelectric generation from the UARP, the HGA will automatically be imposed on customers up to a maximum of 4% of retail revenue. If the balance in the HGA balancing account is equal to 5% of budgeted retail revenue on any date of calculation of the precipitation variance and the precipitation variance results in surplus hydroelectric generation from the UARP, the positive impact of the surplus will be rebated to customers up to a maximum of 4% of retail revenue.

In October 2008, $15 million of the original $30 million balance in the HGA balancing account was transferred to revenues to offset that year's hydroelectric generation variance. An additional $11 million was transferred to revenue in April 2009. The $4 million balance remaining in the HGA balancing account was transferred to revenue in April 2010 and a $0.00004 / kWh HGA surcharge was implemented on all customer bills on April 10, 2010 to collect the balance of replacement power costs due to the deficiency in hydroelectric generation from the UARP in the 12 months ended March 31, 2010.

The District's rates remain significantly below those of PG&E and other large utilities throughout California. The following table sets forth the average charges per kWh by customer class for both the District and PG&E. PG&E's rates reflect their most recently approved rate effective June 1, 2010.

AVERAGE CLASS RATES

	SMUD Rates (cents/kWh)	PG&E Rates (cents/kWh)[1]	Percent Higher Than SMUD
Residential	11.92¢	16.35¢	37%
Small Commercial	12.51	17.91	43
Medium Commercial	11.31	16.04	42
Medium Commercial/Industrial (> 500)	10.49	13.91	33
Large Commercial/Industrial (> 1000 kW)	9.35	11.47	23
Agriculture	11.45	14.20	24
Lighting	10.91	16.25	49
System	11.46	15.25	33

(1) Based on average rates per PG&E filing, Advice Letter 3669-E effective June 1, 2010.

The following table shows a comparison of the District's charges for the average residential usage of 700 kWh per month (based on an average of winter and summer) with similar charges of the four largest utilities in the State.

STATEWIDE COMPARISON–RESIDENTIAL SERVICE

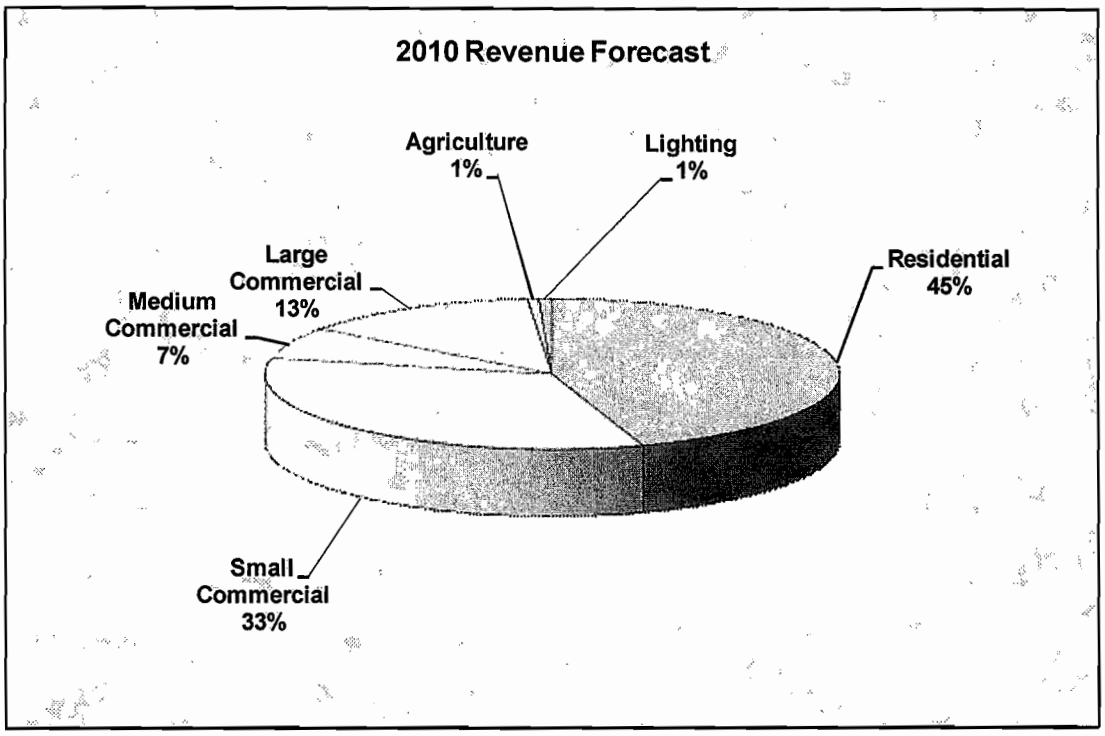
	Monthly Billing Charge 700 kWh	Percent Higher Than SMUD
Sacramento Municipal Utility District	$ 79.77[1]	–
Los Angeles Dept. of Water & Power	90.35[2]	13%
Pacific Gas & Electric Company	106.30[2]	33
San Diego Gas & Electric Company	113.80[2]	43
Southern California Edison Company	115.72[2]	45

(1) Includes approved March 1, 2010 rate increase of 5.5%, January 1, 2010 Solar Surcharge, and April 10, 2010 Hydro Generation Adjustment. Does not include other approved rate increase of 2.25% in 2011.

(2) Per individual utility's published schedules as of 06-01-10.

Allocation of Revenue by Customer Class

The following chart sets forth the forecast percentage of the District revenues from billed sales associated with each customer class.



Customer Base; Largest Customers

A stabilizing influence on the District's revenues is that a substantial proportion is derived from residential customers (46% for 2009). Historically, revenue from commercial and industrial consumption has been more sensitive to economic fluctuation. In 2009, no single customer contributed more than 2.6% of revenues. The top ten customers generated approximately 11% of revenues and the top 30 approximately 17%. The following table presents information on the District's top ten customers as of December 31, 2009.

DISTRICT'S LARGEST CUSTOMERS
(As of December 31, 2009)

Customer Type	Annual Revenue ($ million)	% of Total Revenue
Government	$29.68	2.59%
Government	26.31	2.30
Government	13.98	1.22
Technology	9.78	0.85
Aerospace	9.49	0.83
Grocery	8.38	0.73
Communications	8.24	0.72
Government (Education)	5.66	0.49
Government (Education)	5.61	0.49
Industrial Gases	5.42	0.47
Top 10 Total	**$122.55**	**10.69%**

POWER SUPPLY AND TRANSMISSION

Power Supply Resources

The following table sets forth information concerning the District's power supply resources as of July 1, 2010. Capacity availability reflects rated or nameplate capacities at the District's load center, as well as entitlement, firm allocations and contract amounts.

POWER SUPPLY RESOURCES
(As of July 1, 2010)

Source:	Capacity Available (MW)[1]
Generating Facilities:	
Upper American River Project (hydroelectric)	684
SMUD-Solano Wind Project[2]	48
Solar Photovoltaic[2]	1
Sub-total:	733
Local Gas-Fired Plants:	
SFA (Cosumnes)	500
SPA (Campbell Soup)	163
SPA (McClellan)	72
SCA (Procter & Gamble)	179
CVFA (Carson-Ice)	93
Sub-total:	1,007
Purchased Power:	
Western Area Power Administration	416
Iberdrola/Klamath Falls	255
Pacific Power & Light ("PP&L")	100
Iberdrola Wind	35
Iberdrola Biomass	34
Avista	75
Other Long-Term Contracts	117
Committed Purchases[3]	500
Sub-total:	1,532
Total	3,272

(1) Available capacity is the net capacity available to serve the District's system peak load.
(2) Solar and wind supply resources are intermittent and are shown at the average historical capacity over the past 3 years between 3:00 p.m. and 8:00 p.m., which the District considers its peak period.
(3) Committed Purchases are primarily purchased on a year-ahead to season-ahead basis from various sources.

Power Generation Facilities

Hydroelectric. The District's Upper American River Project ("UARP") consists of three relatively large storage reservoirs (Union Valley, Loon Lake and Ice House) with an aggregate water storage capacity of approximately 400,000 acre-feet and eight small reservoirs. Project facilities also include eight tunnels with a combined length of over 26 miles and eight powerhouses containing 11 turbines. In addition to providing clean hydroelectric power and operating flexibility for the District, the UARP area provides habitat for fish and wildlife and a variety of recreational opportunities, including camping, fishing, boating, hiking, horseback riding, mountain biking and cross-country skiing.

The combined capacity of the UARP is approximately 684 MW at the District's load center in Sacramento. Under current licensing and mean water conditions, these facilities are expected to generate approximately 1,700 gigawatt hours ("GWh") of electric energy annually, which represents approximately 15% of the District's current average annual retail energy requirements. When practicable, the District utilizes hedging contracts designed to reduce the financial impact of varying precipitation and generation from the UARP. The District Board adopted, on May 15, 2008 a rate adjustment mechanism that would collect added revenues in a dry year and reduce revenues collected in a wet year.

In 1957, the Federal Power Commission (predecessor agency to FERC) issued a license to the District for the UARP. This 50-year license was subsequently amended to add and upgrade facilities and now includes all segments of the District's hydroelectric facilities located on the South Fork of the American River and its tributaries. The original FERC license expired in July 2007, at which time FERC issued the District the first of potentially multiple annual license extensions. The issuance of annual extensions is not uncommon in hydroelectric relicensing as the typical relicensing timeframe of 7 years is often inadequate to deal with the complex issues involved. Nevertheless, after several years of negotiations, the District reached a settlement agreement with federal and State regulatory land management agencies, nongovernmental organizations, and other interested stakeholders on proposed terms and conditions to be included in a new FERC license for the UARP. The settlement agreement was filed with the FERC on February 1, 2007. The agreement calls for the District to manage stream flows to accommodate fish habitat and recreational uses (such as boating) and obligates the District to provide other enhancements to recreational facilities. The District staff estimates that the settlement agreement will reduce annual average generation by approximately 100 GWh which, along with agreed upon capital and O&M expenditures, will cost the District approximately $15 million annually. The agreement also includes a proposed 400 MW pumped storage project (the "Iowa Hill Project") which would increase the production capacity of the hydro system up to 60% if the District decides to construct the project. The District has not yet determined whether it will proceed with the Iowa Hill Project and, thus, no specific plans related thereto have yet been developed.

The issuance of the new license is subject to completion of the environmental reviews to be conducted under the National Environmental Policy Act ("NEPA") and the California Environmental Quality Act ("CEQA") and the issuance by the State Water Resources Control Board ("SWRCB") of a Clean Water Act, Section 401 permit. FERC completed the NEPA process in March 2008. The District completed certification of its CEQA documents in September 2008. The SWRCB can now issue the 401 Permit, but the timing of this document is uncertain. Since FERC cannot issue the new license until the 401 Permit is released, the timing of the new license remains unknown, though it could be issued as early as late 2010 or early 2011. Nevertheless, the District expects to be granted annual extensions of its current license until such time as FERC issues the new license.

Solano Wind Project. The District owns and operates a 102 MW wind project, located in Solano County. This project consists of 23 wind turbine generators ("WTG") rated at 660 kilowatts ("kW") each, and 29 WTGs rated at 3 MW each. Energy from the project is collected at 21 kilovolts ("kV") and

transmitted over a dedicated 3 mile overhead system to District-owned Russell substation. At the Russell facility, the energy is transformed to 230 kV and interconnected to PG&E's Vaca-Dixon transmission line. Energy deliveries are scheduled through the California Independent System Operator ("CAISO"). The District is considering further development at the site, potentially adding as much as 125 MW in additional capacity to be on line by 2012, which the District would dispatch and control in addition to the 102 MW currently dispatched and controlled by the District. The District has certified the Final Environmental Impact Report for this potential additional development and issued a Request for Proposals ("RFP") to develop the site. The RFP invited proposals for two alternative ownership structures, a District ownership structure and third party development and ownership structure. The District is currently evaluating responses to the RFP.

Solar Photovoltaic. The District has installed approximately 5 MW of solar photovoltaic generating facilities. These facilities include large installations at the Rancho Seco property, the Hedge Substation property, and other District facilities as well as smaller photovoltaic systems throughout the service area on customer roofs, buildings and parking lots.

Local Gas-Fired Plants. The District has completed construction of five local natural gas-fired plants for its service area: the CVFA Project, the SCA Project, the SPA Project, SPA McClellan and the SFA Project (each defined below). These five plants are referred to collectively as the "Local Gas-Fired Plants." These plants are a strategic component of the District's resource mix. In addition to providing the District a total capacity of approximately 1,007 MW, the Local Gas-Fired Plants provide the District with needed voltage support, operational and load following capability, and the reliability inherent in having power resources located close to loads. With the exception of SPA McClellan, these plants have been financed through the issuance of project revenue bonds by separate joint powers authorities (the "Authorities"). The District has entered into long-term agreements with the Authorities providing for the purchase by the District, on either a take-and-pay or take-or-pay basis as described below, of all of the power from each of the Local Gas-Fired Plants. Although the Local Gas-Fired Plants are owned individually by the Authorities, the District has exclusive control of their dispatch and manages their operations as part of its overall power supply strategy.

Except for payments under the two take-or-pay contracts described below, current payments from the District to the Authorities are subject to reduction or suspension on a monthly basis if the Local Gas-Fired Plants do not meet certain performance standards. The two take-and-pay power purchase agreements between the District and the Authorities described below call for capacity and energy payments. The capacity payments are based on each plant's availability factor (the percentage of time each calendar month that the plant is ready to generate electricity and to meet certain other system needs). In each case, the capacity payment is reduced by one percentage point for each percentage point shortfall in the availability factor below 90%, and suspended if the availability factor is below 70%. The District may terminate the take-and-pay power purchase agreements under certain substandard availability or capacity conditions, which vary for the related Local Gas-Fired Plant.

Payments under the power purchase agreements are payable from revenues prior to the payment of the principal of or interest on the Bonds, as are other maintenance and operation costs and energy payments. For further discussion of the District's obligations to make these payments to the joint powers authorities, see "CAPITAL REQUIREMENTS AND OUTSTANDING INDEBTEDNESS – Outstanding Indebtedness – *Joint Powers Authorities*."

The following is a brief description of the five Local Gas-Fired Plants:

The CVFA Carson Cogeneration Project (the "CVFA Project"). The CVFA Project, a 99.9 MW Net Demonstrated Capacity ("NDC") natural-gas-fired cogeneration project consisting of separate combined cycle and peaking plants, provides steam to Arctic Glacier Ice Company and to the Sacramento Regional County Sanitation District wastewater treatment plant adjacent to the site. The CVFA Project is owned by the CVFA, a joint powers authority formed by the District and the Sacramento Regional County Sanitation District. Construction of the CVFA Project was completed and the plant began commercial operation on October 11, 1995. The take-or-pay power purchase agreement between the District and CVFA will expire no earlier than the date all payments required to be made on or with respect to the related bonds or the related indenture have been paid or discharged in full. In February 2008, the District Board of Directors, along with the CVFA and SCA Commissions, entered into an agreement for upgrading various LM6000 units at CVFA and SCA. At CVFA, only the combined cycle unit was upgraded. This engine upgrade converted the existing LM6000PA unit to an LM6000PC Sprint version. The upgrade was completed in the spring of 2010 and increased the unit's output by approximately 8 MW. The costs of the upgrade will be paid through a contribution from the District to the CVFA Project.

The SCA Procter & Gamble Cogeneration Project (the "SCA Project"). The SCA Project, a 180 MW NDC natural gas-fired cogeneration facility, is located in an established industrial area of Sacramento. The initial combined cycle portion of the plant began commercial operation on March 1, 1997. Construction of the peaking plant portion of the SCA Project commenced during 2000 and the unit achieved commercial status on April 24, 2001. The SCA Project produces steam for use in Procter & Gamble Manufacturing Company's oleochemical manufacturing processes and electricity for sale to the District. The SCA Project is owned by the SCA, a joint powers authority formed by the District and SFA, a separate joint powers authority. The take-or-pay power purchase agreement between the District and SCA will expire no earlier than the date all payments required to be made on or with respect to the related bonds or the related indenture have been paid or discharged in full. In February 2008, the District's Board of Directors, along with the CVFA and SCA Commissions, entered into an agreement for upgrading various LM6000 units at CVFA and SCA. At SCA, both combined cycle units and the simple cycle peaker were included in the upgrade agreement. The combined cycle engine upgrades converted the existing LM6000PA units to LM6000PC Sprint versions. The first combined cycle engine upgrade was completed on June 7, 2008. The second combined cycle engine upgrade was completed on April 10, 2009. The simple cycle engine upgrade added Sprint capability to the existing LM6000PC engine and increased the peaking plant output by approximately 6 MW. The costs of the upgrades have been, and are expected to continue to be, paid through contributions from the District to the SCA Project.

The SPA Campbell Soup Cogeneration Project (the "SPA Project"). The SPA Project, a 159.8 MW NDC natural gas-fired cogeneration project, was completed and began commercial operations on December 4, 1997. Upgrades were implemented during 2000 which increased the plant's peaking capacity to 180 MW, well above its net demonstrated capacity of 159.8 MW. The plant is located in south Sacramento adjacent to the Campbell Soup Company food processing facility. The SPA Project is owned by the SPA, a joint powers authority formed by the District and SFA. The take-and-pay power purchase agreement between the District and SPA expires in December 2027.

The SPA McClellan Gas Turbine ("SPA McClellan"). SPA McClellan is a 72 MW gas-fueled simple cycle combustion turbine generating plant at McClellan Business Park in Sacramento. This turbine is connected to the District's electric system and is operated to meet the District's peak-load requirements. SPA McClellan is aligned for remote starting and operation with both black start and fast start capabilities. The District constructed the McClellan unit in 1986 as a 50 MW emergency power source for the McClellan Air Force Base. In 2001, following the Air Force Base closure, McClellan was

upgraded to 72 MW and converted for District use. In May 2007, the District transferred ownership of the McClellan Gas Turbine to the SPA for more efficient operation. SPA passes all costs of operations and maintenance through to the District in accordance with the terms of a Power Purchase and Operating Agreement ("PPA"). SPA McClellan's PPA expires on May 1, 2037. SPA has no debt related to SPA McClellan. In exchange for paying all costs related to SPA McClellan, the District receives all of the power generated thereby.

The Cosumnes Power Plant (the "SFA Project"). The SFA Project is a 501.2 MW NDC natural gas-fired, combined cycle plant located in the southern portion of Sacramento County adjacent to the District's decommissioned Rancho Seco Nuclear Power Plant. Commercial operation commenced effective February 24, 2006. All energy from the SFA Project is purchased by the District under a take-and-pay power purchase agreement. The power purchase agreement between the District and SFA expires in October, 2039 or when the bonds related to the SFA Project mature. The SFA Project is owned by the SFA, a joint powers authority formed by the District and Modesto Irrigation District ("Modesto").

Fuel Supply

General. The District is obligated to arrange for the purchase and delivery of natural gas to the Local Gas-Fired Plants. Management of the natural gas procurement and delivery process is a key focus of the District's reliability and risk policies. The Local Gas-Fired plants generally supply over 50% of the District's average electric load. Although the natural gas consumption of the power plants can vary significantly depending on the season and the market price of power, the plants require, on average, a total of approximately 125,000 Decatherms per day ("Dths/day") with a daily peak slightly in excess of 160,000 Dths/day of natural gas. The District has implemented a comprehensive strategy to secure a reliable and diversified fuel supply through a variety of agreements and ownership arrangements for the supply, transportation, and storage of natural gas.

Supply. The District hedges a significant portion of its expected gas needs to meet customer power requirements. This is accomplished through a combination of long-term supply arrangements and a rolling three year exposure reduction program. Long-term arrangements may consist of a combination of physical commodity supply contracts, financial hedges, or the outright ownership of proven, developed, and producing natural gas reserves.

In March 2003, the District purchased an ownership interest in natural gas reserves located in the San Juan basin in northern New Mexico from affiliates of El Paso Corp. The property, known as the Rosa Unit, consists of 54,209 acres of producing oil and gas leases totaling over 400 producing gas wells operated by Williams Production Company LLC. The District's share of the production rate is expected to be approximately 20,000 Dths/day to 25,000 Dths/day, which represents approximately 18% of the District's current average daily requirement. The reserves are expected to last roughly 50 years, with production declining gradually over time.

The District has contracted with the Northern California Gas Authority No. 1 ("NCGA") to purchase an approximate average of 12,506 Dths/day over the remaining life of a contract expiring May 31, 2027. The District pays a discounted variable price for the fuel and anticipates periodically fixing the effective price under separate agreements. Currently the delivery point is the AECO hub, in Alberta, Canada and the District is using its long-term transport capacity to deliver it to the local area plants. The Board has authorized staff to obtain up to 80,000 Dths/day of additional discounted supply under multiple supply contracts with similar arrangements. For any future purchases, the District anticipates that the supplies will be financed by tax-exempt entities not affiliated with the District. The District would commit to take the gas for the term of the financings on a pay-as-you-go basis.

Natural gas is purchased from a wide variety of producers and marketers at the northern and southern California borders, at Alberta, Canada and from the San Juan and the Rocky Mountain supply basins. The District has a number of both fixed-price supply agreements and financial hedging contracts to fix gas costs ranging from one month to twenty years in duration. Together with the Rosa Unit reserves, these contracts have fixed the price on about 100% of the District's expected average gas needs through 2013.

Renewable Natural Gas Supply. The District has entered into two contracts for landfill gas that qualifies as renewable energy. First, in March 2009, the District entered into a 15- year contract with Shell Energy North America (US), L.P. ("Shell Energy") to purchase up to 6,000 Dths/day of natural gas produced from a landfill project in Texas. The District began taking deliveries of this supply in April 2009. Currently the delivery point is PG&E Topock and the District is using its long-term transport capacity to deliver it to the SFA Project.

Second, the District contracted with Heartland Renewable Energy, LLC ("HRE") on December 15, 2009 for a 20-year supply of natural gas from a digester facility in Colorado. The District will receive between 3,000 Dths/day and 7,000 Dths/day and deliveries are expected to begin in 2012. Currently the delivery point is Opal, Wyoming and the District is using its long-term transport capacity to deliver it to the SFA Project.

Gas Transmission

The District has satisfied its obligation to deliver natural gas to its power plants by constructing a natural gas pipeline, purchasing an equity interest in two PG&E backbone gas transmission lines, and contracting for capacity on a number of existing interstate natural gas transmission lines.

The Local Pipeline. The District constructed and owns a 20-inch, 51-mile natural gas pipeline in the greater Sacramento area (the "Local Pipeline") that transports gas to all of the Local Gas-Fired Plants except SPA McClellan. The Local Pipeline is interconnected with PG&E's major California Gas Transmission lines 300 and 401. Additionally, it may be interconnected with one or more private gas gathering pipelines located in the area, a gas storage project and/or other FERC approved pipelines that may be built in the local area. In conjunction with the construction of the SFA Project, the District extended the Local Pipeline to the plant site. The 26-mile extension was completed in the third quarter of 2004. The extension is 24 inches in diameter and was designed to serve both the SFA Project and an additional second phase, if constructed.

PG&E Backbone Gas Transmission Lines 300 and 401. In 1997, the District purchased an equity interest in PG&E backbone gas transmission lines 300 and 401 (referred to as the PG&E backbone). The total capacity acquired, 86,000 Dths/day, consists of 43,000 Dths/day of firm gas transport from the California–Oregon border at Malin, and 43,000 Dths/day from the California–Arizona border at Topock, Arizona, to the District's interconnection with the PG&E backbone near Winters, California. The District is also entitled to a share of the non-firm capacity, which is approximately 4,000 Dths/day; making the total capacity available to the District a majority of the time closer to 90,000 Dths/day. The purchase makes the District a co-owner of the PG&E backbone gas transmission lines 300 and 401 and obligates the District to pay PG&E to operate the capacity on its behalf subject to an operating agreement. Because of its ownership interest in the lines, the District is not subject to curtailments ordered by the California Public Utilities Commission ("CPUC") or FERC, which enhances the reliability of the District's transmission arrangements.

The District obtained additional backbone capacity under tariff service for 20,000 Dth/day of northern path (Redwood) capacity and 20,000 Dths/day of southern path (Baja) capacity. This contract expires in June 2011 but the District has an option to extend for another five years.

Transwestern FTS-1 Long Term Agreements. In 2006, the District extended its agreement for 10,000 Dths/day of firm gas transportation capacity on the Transwestern Pipeline from the Blanco Hub in New Mexico to the receipt point into the PG&E system at Topock, Arizona for ten years. The District also obtained an additional 10,000 Dths/day of capacity along the same route, with service through March 2012 and rights to extend the contract under FERC rules at tariff rates. The District also acquired 20,000 Dths/day of additional long-term capacity from Ignacio, Colorado to the Blanco Hub. This capacity is provided through March 2012. These contracts are expected to be extended for one year on an annual basis. These agreements will provide 18,000 to 20,000 Dths/day of long-term capacity from the Ignacio hub to the California-Arizona border, which is sufficient to transport the long-term average projected gas supplied from the Rosa Unit.

Kern River Gas Transmission Company Long Term Agreement. The District has an agreement with Kern River Gas Transmission Company for 20,000 Dths/day of firm capacity through April 30, 2018. This capacity gives the District access to the Rocky Mountain supply basin at Opal, Wyoming, and connects to PG&E Line 300 (owned in part by the District) at Daggett, California.

TransCanada Firm Transmission Service Agreements. The District has several agreements with TransCanada Corporation which gives the District access to Canadian supply from the Alberta basin to Kingsgate, B.C. to the California-Oregon border at Malin. The District has agreements for 22,101 Dths/day at the California-Oregon border at Malin via the GTN pipeline and approximately 12,000 Dths/day from Alberta via the NOVA pipeline to Kingsgate via the ANG/Foothills pipeline, all expiring in 2023. In order to match the Canadian capacity with the take away capacity at Malin, the District has an agreement with Powerex Corporation for approximately 10,000 Dths/day expiring March 31, 2012. The District's diversified portfolio of gas transmission arrangements allow for the purchase of gas from a variety of suppliers and locations, and the opportunity to capitalize on regional price differentials where possible. In addition, its ownership interest in the SMUD/PG&E backbone and Local Pipeline enhances the reliability of the District's gas supply.

Gas Storage

The District also employs gas storage as part of its overall fuel supply strategy. Gas storage is used to balance gas supply, mitigate market price volatility, and provide a reliable backup supply.

The District has a contract with Wild Goose Storage, Inc. expiring on March 31, 2011 for capacity in an expansion of the Wild Goose Storage project located near Yuba City in northern California. The contract provides the District with capacity levels of 2.33 million Dths of storage inventory, 25,674 Dths/day of injection rights and 58,349 Dths/day of withdrawal capacity (withdrawal capacity is reduced to 18,671 Dths/day if the inventory dips below 25%) during this period.

The District signed a contract with a developer to connect a proposed local storage project directly to the District's local pipeline. The proposed storage field is approximately 8 Bcf, and is located approximately one mile from the District's pipeline. The District's share of the field would be up to 4 Bcf with an injection limit of 40,000 Dths/day and 70,000 Dths/day withdrawal. The term is 20 years, with the District expecting to receive storage capacity from 2011 through 2031 if completed. In the event that the proposed storage field is not completed, the District would consider other available storage options.

Power Purchase Agreements

The District has a number of power purchase agreements to help meet its power requirements. Certain of these agreements are described below.

Western. Effective January 1, 2005, the District entered into a 20-year contract with Western. Power sold under this contract is generated by the Central Valley Project ("CVP"), a series of federal hydroelectric facilities in northern California operated by the United States Bureau of Reclamation. The contract provides the District with the right to purchase 31.25% of all power allocated or sold by Western through December 31, 2014. Starting in 2015, the District's allocation under the contract will be reduced to about 25% of total Western power sold. Through the period ending 2014, the District's Base Resource share is expected to be approximately 420 MW of capacity and approximately 899 GWh of energy in an average year, but could vary depending on the availability of water to the CVP. Energy available under the contract is determined by water releases required for water supply and flood control, and is then shaped into higher value periods within other CVP operating constraints. More capacity and energy is typically available in spring and summer months and less delivered in fall and winter.

The District also has a contract with Western, effective January 1, 2005 through September 30, 2010, by which Western delivers 200 MW per hour of Supplemental Power during on-peak hours. The District schedules, and Western accepts, Supplemental Power at the California Oregon Border ("COB") at an agreed upon price. Western delivers the Supplemental Power to the District at the District's Hurley or Elverta 230 kV Substations at the same agreed upon price. The District also pays Western's filed transmission rates for the point-to-point and network transmission service over a combination of Western's rights on the PACI and Western's 230kV grid to deliver the Supplemental Power to the District. By February 1 of each year, the parties renegotiate the amount of Supplemental Power that is provided for off-peak hours, and the extent to which Western will provide an additional 100 MW of Supplemental Power for on- and off-peak hours for the period May 1st through the following April 30th. The District currently anticipates that this contract will be extended. However, no assurance can be given that a contract extension will be successfully negotiated. In the event that the contract is not extended, the District will be required to replace these resources from another source.

Iberdrola Renewables ("Iberdrola"). The District has seven agreements with Iberdrola (formerly known as PPM Energy and PacifiCorp Power Marketing). Two of these agreements were initially transacted with the City of Klamath Falls, Oregon and later acquired by Iberdrola through assignment. Five of these agreements were transacted directly with Iberdrola or a predecessor.

Under these contracts the District receives 130 MW of summer peaking capacity through the fall of 2012 indexed at the price of gas, and 100 MW of capacity and energy through June 2011 also indexed at the price of gas. One of the contracts expiring in June 2011 also provides the District with 25 MW of Renewable Energy Credits ("RECs").

Two of the contracts provide the District with both renewable energy and RECs. These contracts include an agreement for 75 MW of wind power generated in northern California and a 12-year contract for 300 GWh's of biomass energy that commenced July 1, 2009 with an expected average capacity of 43 MW.

Pacific Power and Light. The District has entered into a series of agreements with Pacific Power & Light ("PP&L"), providing 100 MW of capacity and 350,400 megawatt-hour ("MWh") of energy through December 31, 2014. The District pays for the amount of energy delivered based on PP&L's cost of coal. Additionally, the agreement provides for up to 219,000 MWh of provisional

energy. The provisional energy option allows the District to call on the additional energy but requires the District to return the energy during the following calendar year.

Avista. The District has a contract totaling 75 MW for renewable power from biomass and small hydroelectric power plants in the Avista control area located in the northwest United States. This contract extends through 2014 and helps the District meet its RPS.

Vulcan Power Company. In April, 2010 the District entered into a power purchase agreement with Vulcan Power Company ("Vulcan") for the delivery of up to 132 MW (expected to be 120 MW nominal power output) of renewable energy from geothermal generation being developed in north central Nevada, from a Vulcan project known as the Patua Project. The project will be developed in three phases. Phase 1, which is nominally 60 MW, is expected to be online October, 2012, and is expected to deliver an estimated 479 GWhs/yr to the District. Phases 2 and 3 are each nominally 30 MW, and are expected to be online October, 2013, and July, 2014, respectively. Each of phases 2 and 3 are expected to provide the District with 237 GWhs/yr.

Renewable Energy Feed-In Tariff. In September 2009, the District's Board authorized a feed-in tariff program for the purchase of renewable energy from local renewable energy projects connected to the District's distribution system. The District's Board authorized connection of up to 100 MWs under the feed-in tariff under which standard payment rates and standard purchase terms for power are published. The feed-in tariff program was effective starting January 1, 2010. By January 11, 2010, the District had received enough applications to fully reserve the 100 MW queue and to have approximately 20 MWs of applications on a waiting list. The entire queue was reserved by applicants having solar photovoltaic projects. As part of the feed-in tariff process, the District began offering power purchase agreements to applicants in the queue in June 2010. Power purchase agreements with 20 year terms covering just over 60 MWs were recently executed. The District expects that power purchase agreements will be executed with all applicants in the queue for virtually all of the reserved capacity.

Transmission Service Agreements

TANC California-Oregon Transmission Project. The California-Oregon Transmission Project ("COTP") is one part of a three 500-kV line coordinated system known as the California-Oregon Intertie or "COI." The COTP is allocated one-third of the 4800 MW capability of the COI system (see related agreements below). The Transmission Agency of Northern California ("TANC") owns about 87% of the COTP. The District is a member of TANC and a party to Project Agreement No. 3 ("PA3") among the members of TANC, under which it is entitled to about 27.5% of TANC's COTP rights. In 2009, the District acquired approximately an additional 2.5% of COTP rights under a long-term layoff agreement with the cities of Roseville and Palo Alto. The District is obligated to pay its share of TANC's COTP operating and maintenance expenses and debt service, which is equal to its ownership share under PA3 and the long-term layoff agreement, totaling about 30%, provided that its share of such expense is subject to increases (limited to no more than 25% of the District's ownership share under PA3 not including the long-term layoff agreement) in the event of an unremedied default by one or more of the TANC members. The District's payments under this contract, like the District's payments under its other power purchase and transmission service agreements, are treated as "Maintenance and Operation Costs" or "Energy Payments" under the resolutions securing the District's Bonds and Subordinated Bonds. The District relies on its COTP rights to purchase power and obtain renewable resources to supplement its own resources to serve its load.

TANC Tesla-Midway Transmission Service. TANC has a long term contract with PG&E to provide TANC with 300 MW of transmission service between PG&E's Midway Substation and the electric systems of the TANC Members (the "Tesla-Midway Service"). The District's share of the Tesla-

Midway Service had been 46 MW. As part of the long-term layoff agreement, the District acquired an additional 2 MW of South-of Tesla Principles (SOTP) transmission rights for 15 years starting February, 2009 from Roseville bringing the District's share of the Tesla-Midway Service to 48 MW. TANC members also engage in short-term and long-term Tesla-Midway Service arrangements among themselves based on each member's individual interests. The District has obtained 30 MW of additional rights on a short-term basis (less than 4 years).

Bonneville Power Administration. In 2009, the District entered into a transmission service agreement with the Bonneville Power Administration ("BPA") for 60MW of firm point-to-point transmission service from BPA's Hilltop substation in north eastern California to the Malin substation at the California-Oregon border for the purpose of transmitting power under the District's power purchase agreement with Vulcan Power Company for phase 1 of the Patua geothermal project over BPA's 230kV transmission lines.

Pacificorp. In 2009, the District entered into a transmission service agreement with Pacificorp for 60MW of firm point-to-point transmission service across Pacificorp's high voltage step-up transformer at the Malin substation at the California-Oregon border for the purpose of transmitting power under the District's power purchase agreement with Vulcan Power Company for phase 1 of the Patua geothermal project.

Western Area Power Administration. The District does not have a direct interconnection of its power system to the COTP. To facilitate getting its share of COTP power transfers to its system, the District has a long term transmission service agreement with Western that enables the District to move power scheduled on its COTP transmission rights from the terminus of the COTP line at the Tracy substation, to the District's system across Western's transmission system.

Projected Resources

The following tables titled "Projected Requirements and Resources to Meet Load Requirements Energy Requirements and Resources" (the "Energy Table") and "Capacity Requirements and Resources Net Capacity – Megawatts" (the "Capacity Table") describe the District's forecast of resources available to meet its load requirements through the year 2019. Resources are shown on an annualized basis with market purchases netted against surplus sales to arrive at a single net position for each year. Because the District's available resources do not exactly match its actual load requirements on an hourly basis, there are times during a year when resources available will either exceed or be insufficient to meet the District's needs. Expected actual capacity values are included in the tables. These values may differ from measured NDC values of the Local Area Gas-Fired Plants. The table below also includes the impact energy efficiency has on resource requirements as discussed below under "Demand Side Management Programs." *See* "BUSINESS STRATEGY" and "Power Generation Facilities—*Local Gas-Fired Plants*."

Resources listed in both the Energy Table and the Capacity Table are listed as either renewable or non-renewable. Generally, the District follows the California Energy Commission ("CEC") guidelines for eligibility requirements. Some of the District's renewable resources listed include wind, small hydro, and biomass. Small hydro is a hydroelectric facility with a capacity of 30 MW or less. Biomass represents generation from a fuel comprised of agricultural wastes and residues, landscape and tree trimmings, wood and wood waste. One resource, the Iberdola – Renewable Energy Credits entry, is to identify a non-renewable power supply bundled with RECs, which qualifies for some renewable energy programs within the District, but not others.

As in any forecast, assumptions are made. In both the Energy Table and the Capacity Table the Western and UARP forecasts assume average water conditions throughout the period. UARP forecasts assume re-licensing goes into effect in 2011. On the capacity table, Western and CVFA renewable capacity is estimated based on the ratio of renewable energy to total Western or CVFA energy. See "Power Generation Facilities – *Hydroelectric*" above.

Statewide photovoltaic goals were established by the State under Senate Bill 1 ("SB1") in 2006 to provide 3,000 MW of solar power. The District's goals to assist the State in meeting its goals are shown separately from the District's other photovoltaic goals.

The Uncommitted Purchases Projects (Sales) on the tables represent either anticipated future needs or surpluses. Future needs are met well in advance of delivery. They also include both renewable and non-renewable resources.

The Transmission Losses represent reductions in the amount of energy or capacity from the location it was purchased to the point of entering the District's electrical system. This amount reduces the Total Resources available to meet the Total Projected Energy Requirements of the electrical system.

Also, on the Capacity Table, Total Resources include a 15% margin for reserves.

Demand Side Management Programs

The District's demand-side management initiatives represent an integral element of its total resource portfolio, and are organized into two major components: energy efficiency and load management programs. Energy efficiency offerings include a wide variety of programs and services to customers to retrofit or upgrade existing equipment and fixtures and to install new energy efficiency measures in existing and new construction facilities. Load management allows the District to reduce the load on the electric system by cycling residential air conditioning, and calling upon commercial/industrial customers to curtail energy usage when energy is constrained during the summer or system emergencies. Load management programs are projected to allow the District to shed approximately 200 MW of peak load in an emergency on a hot day, representing about 6% of the District's maximum system peak demand.

A new customer metering system with 2-way communication capability is expected to assist the District in reducing energy requirements, and more importantly, peak demand. Information from this system regarding customer usage patterns is expected to help the District tailor rate designs that provide customers with both the information and ability to manage their energy usage around high energy cost periods.

PROJECTED REQUIREMENTS AND RESOURCES TO MEET LOAD REQUIREMENTS[1]
ENERGY REQUIREMENTS AND RESOURCES (GWh)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Renewable Resources										
District or Joint Powers Authority Owned:										
UARP Small Hydro	54	59	59	59	59	59	59	59	59	59
Photovoltaic – Solar	3	2	2	2	2	2	2	2	2	2
Solano Wind	276	273	673	673	673	673	673	673	673	673
SFA – Shell Landfill	244	408	619	614	614	702	702	702	702	755
CVFA – Digester Gas	46	13	-	-	-	-	-	-	-	-
Total	**622**	**755**	**1,354**	**1,348**	**1,348**	**1,437**	**1,437**	**1,437**	**1,437**	**1,489**
Purchases										
Western Small Hydro	17	21	18	18	18	15	15	15	15	15
Iberdrola – Renewable Energy Credits	198	103	0	0	0	0	0	0	0	0
Iberdrola Wind	224	224	224	224	224	111	0	0	0	0
Iberdrola Biomass	339	339	340	339	339	339	339	339	339	339
Avista – Biomass and Small Hydro	657	657	659	547	438	0	0	0	0	0
Vulcan – Geothermal	0	0	119	533	711	711	711	711	711	711
Other Long-Term Contracts	507	634	709	760	760	578	477	422	346	345
Total	**1,942**	**1,978**	**2,069**	**2,420**	**2,489**	**1,753**	**1,542**	**1,487**	**1,410**	**1,410**
Non-Renewable										
District or Joint Powers Authority Owned:										
UARP	1,621	1,555	1,542	1,563	1,563	1,563	1,563	1,563	1,563	1,563
SFA	3,676	3,208	3,336	3,336	3,247	3,247	3,247	3,247	3,247	3,195
CVFA	342	419	443	447	447	447	447	447	447	447
SCA	909	883	893	907	907	907	907	907	907	907
SPA – McClellan	3	2	2	0	0	0	0	0	0	0
SPA	1,096	1,090	1,126	1,148	1,148	1,148	1,148	1,148	1,148	1,148
Total	**7,647**	**7,158**	**7,342**	**7,399**	**7,399**	**7,311**	**7,311**	**7,311**	**7,311**	**7,259**
Purchases										
Western Large Hydro	835	1,015	883	881	881	710	710	710	710	710
Iberdrola	496	145	50	0	0	0	0	0	0	0
PP&L	569	569	569	569	569	0	0	0	0	0
WAPA Customer (wheeling)	36	44	38	38	38	38	38	38	38	38
Committed Purchases (Sales)	0	352	0	0	0	0	0	0	0	0
Total	**1,936**	**2,124**	**1,539**	**1,487**	**1,487**	**748**	**748**	**748**	**748**	**748**
Uncommitted Purchase Projects (Sales)	(936)	(856)	(1,166)	(1,519)	(1,602)	9	587	952	1,119	1,207
Total Resources	**11,211**	**11,159**	**11,138**	**11,136**	**11,122**	**11,258**	**11,624**	**11,935**	**12,025**	**12,112**
Transmission Losses (COTP/CVP)	90	90	91	90	73	33	33	34	36	37
Total Projected Energy Requirements	**11,121**	**11,068**	**11,048**	**11,045**	**11,049**	**11,226**	**11,591**	**11,901**	**11,990**	**12,075**
Energy Efficiency Goals	76	214	353	498	644	788	887	968	1,048	1,126
SB1 Photovoltaic Goals	27	45	55	65	74	97	108	137	166	199
Other SMUD PV Programs	0	0	0	0	0	0	0	0	0	0
Total Gross Energy Requirements before EE and Solar PV Programs	**11,224**	**11,327**	**11,456**	**11,608**	**11,766**	**12,110**	**12,586**	**13,006**	**13,204**	**13,400**

(1) Totals may not sum due to rounding.

CAPACITY REQUIREMENTS AND RESOURCES[1]
NET CAPACITY – MEGAWATTS

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Load:										
Planned Peak before EE/SB1	3,004	3,022	3,050	3,086	3,129	3,179	3,293	3,410	3,461	3,512
Energy Efficiency Goals	(19)	(54)	(86)	(120)	(145)	(171)	(234)	(256)	(278)	(303)
SB1 Photovoltaic Goals	(8)	(13)	(17)	(20)	(23)	(29)	(33)	(42)	(50)	(56)
Other District Photovoltaic Programs	0	0	0	0	0	0	0	0	0	0
Planned Peak	2,958	2,937	2,929	2,928	2,943	2,960	3,008	3,095	3,115	3,135
Transmission Losses (COTP/CVP)	18	18	18	18	18	18	18	18	18	18
Non Dispatchable Demand Resource	(61)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)
Adjusted peak	2,915	2,899	2,891	2,890	2,905	2,922	2,970	3,056	3,077	3,096
Renewable Resources										
District or Joint Powers Authority Owned:										
UARP Small Hydro	36	36	36	36	36	36	36	36	36	36
Photovoltaic – Solar	1	1	1	1	1	1	1	1	1	1
Solano Wind	48	48	108	108	108	108	108	108	108	108
SFA – Shell Landfill	31	56	78	78	78	89	89	89	89	96
CVFA – Digester Gas	11	3	3	3	0	0	0	0	0	0
Dispatchable Demand Resource	139	127	121	113	113	113	113	113	113	113
Total	**266**	**271**	**347**	**339**	**336**	**347**	**347**	**347**	**347**	**353**
Purchases										
Western Small Hydro	14	14	14	14	14	14	14	14	14	14
Iberdrola – Renewable Energy Credits	25	0	0	0	0	0	0	0	0	0
Iberdrola Wind	35	35	35	35	0	0	0	0	0	0
Iberdrola Biomass	34	34	34	34	34	34	34	34	34	34
Avista – Biomass and Small Hydro	75	75	75	50	50	0	0	0	0	0
Vulcan Geothermal	0	0	0	58	116	116	116	116	116	116
Other Long-Term Contracts	58	85	109	131	131	97	97	97	82	82
Total	**241**	**244**	**267**	**322**	**345**	**261**	**261**	**261**	**246**	**246**
Non-Renewable										
District or Joint Powers Authority Owned:										
UARP	649	649	649	649	649	649	649	649	649	649
SFA	469	444	422	422	422	411	411	411	411	404
CVFA	82	98	98	98	93	93	93	93	93	93
SCA	179	179	179	179	179	179	179	179	179	179
SPA – McClellan	72	72	72	72	72	72	72	72	72	72
SPA	163	163	163	163	163	163	163	163	163	163
Total	**1,614**	**1,604**	**1,582**	**1,582**	**1,577**	**1,566**	**1,566**	**1,566**	**1,566**	**1,559**
Purchases										
Western Large Hydro	402	402	402	402	402	402	322	322	322	322
Iberdrola	230	130	130	0	0	0	0	0	0	0
PP&L	100	100	100	100	100	0	0	0	0	0
Other Long-term Contracts	17	17	17	17	17	17	17	17	17	17
Firm Contract Reserves	42	37	37	30	30	22	18	18	18	18
Committed Purchases	500	0	0	0	0	0	0	0	0	0
Total	**1,291**	**687**	**687**	**550**	**549**	**441**	**356**	**356**	**356**	**356**
Uncommitted Purchases	0	529	441	530	534	745	885	985	1,024	1,046
Total Resources	**3,411**	**3,334**	**3,324**	**3,323**	**3,341**	**3,360**	**3,415**	**3,515**	**3,539**	**3,561**

(1) Totals may not sum due to rounding.

Balancing Authority Area Agreements

The District began operating as an independent balancing authority ("BA") on June 18, 2002 within the WECC reliability organization's region, departing from the CAISO BA. This reduced the District's exposure to the costs and reliability risks of the CAISO's markets. Subsequently, the District has expanded its operational footprint beyond the District's service territory to include Western's electric system (on January 1, 2005) and the COTP (on December 1, 2005). The District has contracts with both Western and TANC to provide specified services and in 2010 will receive compensation totaling $3.7 million from them. The agreement with Western among other terms, establishes operating reserve obligations between the parties. Western in turn has agreements with electric systems connected to it to assure that such systems also operate reliably (i.e. Modesto Irrigation District ("Modesto"), the City of Roseville ("Roseville") and the City of Redding ("Redding")). Additionally, the District has certain interconnection and operations agreements with other interconnecting BA areas (i.e. CAISO, BPA and the Turlock Irrigation District ("TID")). These agreements provide for the operation, maintenance and coordination of the interconnections. They also contain emergency assistance arrangements, in compliance with the reliability standards issued by NERC.

The Energy Policy Act of 2005 gave FERC authority to enforce reliability standards for the bulk electric system. In June 2007 these standards became enforceable and the District was audited in Winter 2007 and is scheduled for an audit in August 2010. Certain of these reliability standards apply to the District's operation of the BA. In order to share the cost of penalties among the parties operating within the BA, the District developed the Reliability Standards Performance Agreement and is now transitioning the operation of the District BA to an newly created entity known as the Balancing Authority of Northern California as explained further below.

Reliability Standards Performance Agreement. With the implementation of Mandatory Reliability Standards by the North American Electric Reliability Corporation ("NERC"), the District executed agreements with the electric systems within its BA area (Modesto, Roseville and Redding) in December 2008. Under these Agreements the parties established a process to share penalties if the actions of the party caused the District to incur a penalty under the Reliability Standards applicable to the District as the BA. The agreement is intended to be transitional as the parties agreed to establish a joint powers agency to be the new BA in place of the District BA.

Balancing Authority of Northern California. The District, Modesto, Roseville and Redding executed a Joint Exercise of Powers Agreement ("JPA Agreement") creating the Balancing Authority of Northern California ("B.A.N.C.") on May 8, 2009. B.A.N.C. has elected commission members and taken other steps necessary to establish itself and has retained legal counsel to establish agreements among the members and implement operation as a BA. Liability for penalties associated with BA related reliability standards will be shared as provided in such agreements. The District will be the BA operator under contract and will continue to perform BA functions on behalf of B.A.N.C. much as it does now as the District BA. The JPA Agreement assigns cost responsibility based on load, with the District representing approximately 70% of the total load. The transition to operation of the B.A.N.C. is expected to be implemented by the end of the first quarter 2011.

Power Pool and Other Agreements

Northwest Power Pool Agreement. The Northwest Power Pool ("NWPP") is an agreement among over 30 utilities and public agencies in the western United States to coordinate planning and operations. The District became a member in February 2007. The principal feature of the NWPP is the Reserve Sharing Program ("RSP") which permits participants to rely on one another in the event that any participant experiences a generating resource outage. The District and Western executed a letter

agreement for implementation of reserve sharing on April 24, 2009. The District began participation in the RSP on November 4, 2009. Under the RSP the District and TID (also a NWPP member) share their reserve amounts and when necessary may call upon NWPP reserves using their COTP rights. The NWPP RSP permits members to operate more efficiently by reducing the reserves that they would otherwise need to have available if they could not rely on each other.

TANC-SMUD OASIS Administration Agreement. The District entered into an agreement with TANC to provide OASIS services (transmission sales and scheduling related services in the District BA of TANC members' COTP rights) on September 29, 2005. The District is compensated for performing these services. TANC and the District are reviewing the terms, conditions and compensation to clarify each party's role for regulatory reliability standards compliance responsibilities and take into account the District's increased efforts related to supporting TANC's compliance requirements. TANC includes the costs of this service in its annual budgets and recovers it from its members who use the TANC OASIS to make their COTP transmission available to third parties.

Other Agreements with PG&E

Background. The District's electric system was originally purchased from PG&E in 1947. The District's service area is mostly surrounded by PG&E's service area and the two electric systems are interconnected at the District's Rancho Seco and Lake-Gold Hill 230-kV substations.

Interconnection Agreement. PG&E and the District executed a Replacement Interconnection Agreement ("RIA") which became effective on January 1, 2010. The RIA provides that the District and PG&E operate their interconnections reliably, plan their electric systems to meet their load requirements, and avoid or mitigate impacts they cause by certain electric system modifications. The new agreement has a termination date of December 31, 2024, subject to FERC approval.

Generator Interconnection Agreements. The District signed a Large Generator Interconnection Agreement with CAISO and PG&E for the potential new development at the Solano Wind Project site, effective December 16, 2008 with a 50-year term. The existing Solano Wind Project is interconnected through a Small Generator Interconnection Agreement and a Large Generator Interconnection Agreement, also with the CAISO and PG&E. Both agreements became effective in January 2010 and both have terms of 20 years. Prior to January 2010 the Solano Wind Project was interconnected under two Special Facilities Agreements.

Other generator interconnection agreements include a Small Generator Interconnection Agreement for Camp Far West with CAISO and PG&E for a 22-year term and a Small Generator Interconnection Agreement with PG&E for Slab Creek with a 22-year term. Both agreements became effective on January 14, 2010.

MISCELLANEOUS

This Official Statement includes descriptions of the terms of the 2010 Series W Bonds, power purchase agreements with certain other parties, pooling and other agreements, the Resolution and certain provisions of the Act. Such descriptions do not purport to be complete, and all such descriptions and references thereto are qualified in their entirety by reference to each such document.

Copies of the Resolution, which forms a contract with the holders of the 2010 Series W Bonds, will be made available upon request.

This Official Statement has been duly authorized by the Board.

SACRAMENTO MUNICIPAL UTILITY DISTRICT

By: /s/ John DiStasio
General Manager

Exhibit D

DECLARATION OF COLIN BAILEY

1. My name is Colin Bailey. I am a staff attorney with Legal Services of Northern California. I am licensed to practice law in the State of California.

2. I am co-counsel for the Avondale Glen Elder Neighborhood Association (AGENA) in *Application of Sacramento Natural Gas Storage, LLC, for a Certificate of Public Convenience and Necessity*, Application Number 07-04-013, currently pending before the California Public Utilities Commission (CPUC).

3. I submitted two Public Records Act (PRA) requests to the Sacramento Municipal Utilities District (SMUD) on behalf of AGENA, the first of these on June 9, 2010 and the second on June 15, 2010. SMUD produced documents simultaneously in response to both of the aforementioned PRA requests. I reviewed the documents SMUD produced in person at SMUD on July 26, 2010. Included among documents produced by SMUD in response to AGENA's PRA requests was the document titled, "SMUD 2009 Ten-Year Transmission Plan Assessment", labeled "FINAL" and dated November 17, 2009. A true and correct copies of the title page and pages I - V of the SMUD 2009 Ten-Year Transmission Plan Assessment I reviewed at SMUD on July 26, 2010 are attached to this declaration at Attachment 1.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct. Executed August 26, 2010 at Sacramento, California.

Colin Bailey

Colin Bailey
Attorney for AGENA

Attachment 1

SMUD
2009 Ten-Year Transmission Plan Assessment

FINAL

November 17, 2009

SMUD
Sacramento Municipal Utility District

Prepared by: _____ Date: 12/4/09
Foung Mua
Senior Transmission Planning Engineer
Grid Planning

Approved by: Craig Cameron Date: 12/4/09
Craig Cameron
Supervisor
Grid Planning

Approved by: _____ Date: _____
Vicken Kasarjian
Director
System Operations and Reliability

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Executive Summary

SMUD performs an annual electric transmission system assessment to ensure that SMUD's transmission facilities continue to meet all applicable NERC/WECC Reliability Standards for the near-term (years one through five) and long-term (years six though ten) planning horizons.

For this report, SMUD performed

- *A ten year planning assessment of the SMUD transmission system*

  A comprehensive assessment of the Sacramento Area electric transmission system was performed to ensure that NERC/WECC Reliability Standards are met through the ten year planning horizon. This year's assessment focused on years 2010 through 2019 that addressed the bulk electric system issues that impact both the LSC and the local area In addition, it also evaluated the system impacts resulting from extreme bulk electric system disturbances.

- *An annual SMUD load serving capability (LSC) study*

  The LSC is the maximum load that can be served with all facilities in service while meeting all applicable reliability standards.

  For the near-term planning horizon (2010 through 2014) with the committed projects described in Table E-1, studies demonstrate that the District will be able to reliably serve load in all years

  Several project alternatives provide margin above load serving requirements for the long-term planning horizon (2015 through 2019). A brief description of these projects is provided in Table E-2 For planning and modeling purposes only, the projects in Table E-2 are shown with preliminary in-service dates. No final decision has been made as to the timing or staging of these projects The District will evaluate the need and timing of these projects and make a recommendation in future assessments

  Figure E-1 provides a graphical representation of the District's LSC compared to the managed high growth demand forecasts with all the committed and proposed projects in-service as described in Tables E-1 and E-2

- *System reliability risk studies based on WECC/NERC planning standards*

  SMUD used the 2009 Pacific Gas and Electric (PG&E) Expansion Plan power flow base cases as a basis for this assessment. These cases incorporated a 1-in-10 year adverse peak load for both SMUD and the surrounding Sacramento Area All Category A, B, C, and D contingencies were run

against the base cases to identify any reliability concerns within the SMUD Area.

- *Transmission upgrade proposals to address reliability risks*

  The 2009 Ten-Year Assessment Plan has identified no new upgrade proposals based on performed power flow, PV, and QV analyses.

- *Summarized planned transmission projects*

  The committed projects identified in Table E-1 provide margin above LSC requirements to meet the 1-in-10 year load forecasts and meet the NERC/WECC Reliability Standards for years 2010 through 2014. Funds have been approved for their construction in order to meet the in-service dates described in the table. A more detailed discussion of these projects can be found in Chapter 5 of this report.

Table E-1: Near-Term (Years 1-5) Planned Transmission Projects

Project Name	Project Description	Project Status	Expected In-Service Date
Cordova 230/69 kV Substation	New Distribution Substation	Committed	May 31, 2010
Upgrade SMUD Cogeneration Fleet	Upgrade turbine equipment	Committed	May 31, 2008 – May 31, 2010
Install 150 MVAr of Transmission Capacitors	Install transmission capacitors	Committed	May 31, 2009 – May 31, 2011
O'Banion-Elverta /Natomas 230 kV Project	New 230 kV DCTL between O'Banion and Elverta/Natomas Substations	Committed	May 31, 2011

The following project proposals identified in Table E-2 provide margin above the 1-in-10 year load forecasts and meet the NERC/WECC Reliability Standards for study years 2015 through 2019. A more detailed discussion of these projects can be found in Chapter 5 of the report.

Table E-2: Long-Term (Years 6-10) Proposed Transmission Projects

Project Name	Project Description	Project Status	Proposed In-Service Date
Franklin 230/69 kV Substation	New Distribution Substation	Proposed	May 31, 2015
O'Banion-Sutter 230 kV DCTL Conversion	Add circuit breakers to convert O'Banion-Sutter line to double circuit tower line	Proposed	May 31, 2016
Iowa Hill Pump Storage Facility	New Hydro Plant in the UARP	Proposed	May 31, 2017
Install 200 MVAr of transmission capacitors	Install transmission capacitors	Proposed	May 31, 2017
Lake-Folsom 230 kV and Folsom-Orangevale 230 kV Reconductoring	Reconductor the Lake-Folsom-Orangevale 230 kV Lines	Proposed	May 31, 2017

In addition to the aforementioned projects, other projects that could add transmission system infrastructure to increase the SMUD LSC include the following:

- A 500 kV transmission line interconnection to WAPA's Tracy station
- Convert the McClellan peaker into a synchronous condenser
- Static Var Systems added in the SMUD service area
- Modification or removal of the Lake – Gold Hill series reactor
- Resource Projects
    - Hybrid solar-thermal plant
    - Solar-thermal augmentation of CPP
    - Redesigned Dispatchable Demand Response

These projects are currently in the conceptual phase with preliminary studies underway.

- *A sensitivity power flow study with unmanaged peak forecasts*

To evaluate the impacts to the transmission system at higher than forecasted load levels, a sensitivity case was done that does not include the planned expansions of SMUD's energy efficiency (EE) and SB1 programs. The intent of this sensitivity is to support a screening level analysis of these programs and the documented power flow results are given for informational purposes only.

Power flow studies demonstrated the following transmission lines could experience thermal overloads under emergency conditions with the higher load levels that results from no energy efficiency or solar capacity:

- Hurley-Natomas 230 kV
- North City-Station A 115 kV #1 and #2
- Hurley-North City 115 kV #2

In addition, the 230 kV voltage could drop below 218 kV (0.95 pu) for the loss of the O'Banion-Sutter 230 kV Line.

CERTIFICATE OF SERVICE BY ELECTRONIC MAIL OR U.S. MAIL

I, the undersigned, state that I am a citizen of the United States and am employed in the City and County of Sacramento; that I am over the age of eighteen (18) years and not a party to the within cause; and that my business address is 455 Capital Mall, Suite 210, Sacramento, CA 95814.

I am readily familiar with the business practice of the City of Sacramento for collection and processing of correspondence for mailing with the United States Postal Service. In the ordinary course of business, correspondence is deposited with the United States Postal Service the same day it is submitted for mailing. On the August 27, 2010, I served a true copy of:

AVONDALE GLEN ELDER NEIGHBORHOOD ASSOCIATION'S REQUEST FOR OFFICIAL NOTICE

[XX] By Electronic Mail – serving the enclosed via e-mail transmission to each of the parties listed on the official service list for A.07-04-013 with an e-mail address.

[XX] By U.S. Mail – by placing the enclosed for collection and mailing, in the course of ordinary business practice, with other correspondence of the City of Sacramento, enclosed in a sealed envelope, with postage fully prepaid, addressed to those parties listed on the official service list for A.07-04-013 without an e-mail address.

I certify and declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on this August 27, 2010 at Sacramento, California.

/s/ Matthew C. Tabarangao
Matthew C. Tabarangao

CALIFORNIA PUBLIC UTILITIES COMMISSION
Electronic Mail Service Lists

Proceeding: A0704013 - Sacramento Natural Gas
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