State of California

Department of Water Resources

Determination of Revenue Requirements

For the Period

January 1, 2009 through December 31, 2009

Submitted To
The California Public Utilities Commission
Pursuant To
Sections 80110 and 80134 of the California Water Code

August 6, 2008

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A. THE DETERMINATION

GENERAL

Pursuant to Section 80110 of the California Water Code, the Rate Agreement between the State of California Department of Water Resources ("Department" or "DWR") and the California Public Utilities Commission ("Commission" or "CPUC"), dated March 8, 2002 ("Rate Agreement"), and Division 23, Chapter 4, Sections 510–517 of the California Code of Regulations ("Regulations"), the Department hereby issues its Determination of Revenue Requirements for the period January 1, 2009 through December 31, 2009 ("2009 Determination"). Capitalized terms used and not otherwise defined herein have the meanings given to such terms in the Rate Agreement or the Indenture under which the Department's Power Supply Revenue Bonds were issued (the "Bond Indenture").

The costs of the Department's purchases to meet the net short requirements of retail end use customers in the three California investor-owned utilities ("Utilities" or "IOUs") namely, Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE") and San Diego Gas & Electric Company ("SDG&E") service territories, including the costs of administering the long-term contracts, are to be recovered from payments made by customers and collected by the IOUs on behalf of the Department. The terms and conditions for the recovery of the Department's costs from customers are set forth in the Act, the Regulations, the Rate Agreement and orders of the Commission. Among other things, the Rate Agreement contemplates a "Bond Charge" (as that term is defined in the Rate Agreement) that is designed to recover the Department's costs associated with its bond financing activity ("Bond Related Costs") and a "Power Charge" (as that term is defined in the Rate Agreement) that is designed to recover "Department Costs", or the Department's "Retail Revenue Requirements" (as those terms are defined in the Rate Agreement), including power supply-related costs. Subject to the conditions described in the Rate Agreement and other Commission Decisions, Bond Charges and certain charges designed to recover Department Costs may also be imposed on the customers of Electric Service Providers (as that term is defined in the Rate Agreement).[1] Additional background material is contained in the Department's prior Determinations of Revenue Requirements, copies of which have been incorporated into the administrative record supporting this Determination.

Pursuant to Sections 80110 and 80134 of the California Water Code and the Rate Agreement, this 2009 Determination contains information on the amounts required to be recovered, on a cash basis, in the 2009 Revenue Requirement Period (calendar year 2009).

For the 2009 Revenue Requirement Period, this 2009 Determination contains information regarding the following[2]: (a) the beginning balance of funds on deposit in the Electric Power Fund ("Fund"), including the amounts on deposit in each account and sub-account of the Fund; (b) the amounts projected to be necessary to pay the principal and interest on all bonds as well as

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[1] Under the Rate Agreement, the "Retail Revenue Requirement" is the amount to be recovered from "Power Charges" on IOU customers. The assessment on customers of Electric Service Providers of charges to recover Department Costs (e.g., "Direct Access Power Charge Revenues") reduces the amount of the "Retail Revenue Requirement," but has no material impact on the Department's costs.

[2] Where appropriate, the Department has provided information in this 2009 Determination on a quarterly basis. In other instances, particularly where information might be considered market-sensitive, the Department has provided information on an annual basis. Within this 2009 Determination, quantitative statistics presented in tabular form may not add due to rounding.

all other Bond Related Costs as and when the same are projected to become due, and the projected amount of Bond Charges required to be collected for such purpose; and (c) the amount needed to pay the Department's costs, including all Retail Revenue Requirements.

DETERMINATION OF REVENUE REQUIREMENTS

Pursuant to the Act, the Rate Agreement and the Regulations, the Department determines, on the basis of the materials presented and referred to by this 2009 Determination (including the materials referenced in Section J), that its cash basis revenue requirement for 2009 is $4.890 billion, consisting of $4.060 billion in Power Charges and $0.829 billion in Bond Charges.

This 2009 Determination takes into account preliminary actual operating results through June 2008.

Any net surpluses or deficiencies during the 2008 Revenue Requirement Period, which may result from the receipt of funds related to various litigation settlements involving the Department, variances in actual natural gas prices than those forecast and other considerations, are reflected in the Department's projected beginning 2009 operating balances.

Table A-1 shows a summary of the Department's revenue requirements and the accounts associated with projected Department Costs ("Power Charge Accounts") for 2009. These figures are compared to those reflected in the Department's final 2008 revenue requirement determination, as reflected in the Department's Supplemental 2008 Determination of Revenue Requirements for the period of January 1, 2008 through and including December 31, 2008 (as so reflected, the "2008 Determination"). A summary and comparison of the Department's revenue requirements and the accounts associated with its Bond Related Costs ("Bond Charge Accounts") is presented in Table A-2. Definitions of key accounts and sub-accounts are presented within each table.

TABLE A-1
SUMMARY OF THE DEPARTMENT'S 2009 POWER CHARGE REVENUE REQUIREMENTS AND POWER CHARGE ACCOUNTS AND COMPARISON TO 2008[1]
($ Millions)

Line	Description	2009[2]	2008[3]	Difference
1	*Beginning Balance in Power Charge Accounts*			
2	Operating Account	930	1,109	(179)
3	Priority Contract Account	-	115	(115)
4	Operating Reserve Account	548	612	(64)
5	**Total Beginning Balance in Power Charge Accounts**	**1,478**	**1,836**	**(358)**
6	*Power Charge Accounts Operating Revenues*			-
7	Power Charge Revenues[4]	4,060	3,162	899
8	Other Revenue[5]	70	60	10
9	Interest Earnings on Fund Balances	42	86	(45)
10	**Total Power Charge Accounts Operating Revenues**	**4,172**	**3,308**	**865**
11	*Power Charge Accounts Operating Expenses*			-
12	Administrative and General Expenses	28	28	-
13	Total Power Costs[6]	4,205	3,690	514
14	**Total Power Charge Accounts Operating Expenses**	**4,232**	**3,718**	**514**
15	Net Operating Revenues	(60)	(410)	350
16	**Ending Aggregate Balance in Power Charge Accounts**	**1,418**	**1,426**	**(8)**

Target Minimum Power Charge Account Balances	Target (Millions of Dollars)		
Operating Account: This minimum balance is targeted to cover intra-month volatility as measured by the maximum difference in revenues and expenses in a calendar month.	425	337	88
Operating Reserve Account: Covers deficiencies in the Operating Account. It is sized as the greater of (i) the maximum seven-month difference between operating revenues and expenses as calculated under a stress scenario, (ii) 12% of the Department's annual operating expenses and (iii) an amount equal to the maximum projected monthly contract cost payment.	667	548	119
Total Operating Reserves:	1,091	885	207

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]As reflected in the 2008 Supplemental Determination.
[4]Includes Bundled customer revenues and Cost Responsibility Surcharge revenues, whether from Direct Access or other sources, such as Community Choice Aggregation.
[5]Other revenues received by the Department are those related to surplus energy sales conducted by the IOUs when the IOUs and the Department have procured more energy than is needed to serve retail customers; details related to surplus energy sales are further discussed in Section D.
[6]Includes gas hedging and collateral amounts.

TABLE A-2
SUMMARY OF THE DEPARTMENT'S 2009 BOND CHARGE REVENUE REQUIREMENTS AND BOND CHARGE ACCOUNTS AND COMPARISON TO 2008[1]
($ Millions)

Line	Description	2009[2]	2008[3]	Difference
1	*Beginning Balance in Bond Charge Accounts*			
2	Bond Charge Collection Account	231	273	(43)
3	Bond Charge Payment Account	621	560	61
4	Debt Service Reserve Account	917	930	(13)
5	**Total Beginning Balance in Bond Charge Accounts**	**1,769**	**1,764**	**5**
6	*Bond Charge Accounts Revenues*			
7	Bond Charge Revenues from Utiltities[4]	829	831	(1)
8	Bond Charge Revenues from Direct Access Customers	-	-	-
9	Interest Earnings on Fund Balances	58	84	(26)
10	**Total Bond Charge Accounts Revenues**	**887**	**914**	**(27)**
11	*Bond Charge Accounts Expenses*			
12	Debt Service on Bonds[5]	920	935	(15)
13	**Total Bond Charge Accounts Expenses**	**920**	**935**	**(15)**
14	Net Bond Charge Revenues	(33)	(21)	(12)
15	**Ending Aggregate Balance in Bond Charge Accounts**	**1,736**	**1,743**	**(7)**

Target Minimum Bond Charge Account Balances	Target (Millions of Dollars)		
Bond Charge Collection Account: An amount equal to one month's required deposit to the Bond Charge Payment Account for projected debt service	76 - 78	78 - 80	
Bond Charge Payment Account: An amount equal to the debt service accrued and unpaid through the end of the third next succeeding calendar month	320 - 860	324 - 825	
Debt Service Reserve Account: Established as the maximum annual debt service	919	937	(18)

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]As reflected in the 2008 Supplemental Determination.
[4]Cost Responsibility Surcharge revenues are included in this amount, whether from Direct Access or other sources, such as Community Choice Aggregation.
[5]Debt service on bonds includes net qualified swap payments.

FUTURE ADJUSTMENT OF REVENUE REQUIREMENTS

The Department may propose to revise its revenue requirements for the 2009 Revenue Requirement Period given the potential for significant or material changes in the California energy market including changes in forecasted fuel costs, the status of market participants, decisions made in connection with the California Independent System Operator's Market Redesign and Technology Upgrade ("MRTU") proceeding, the Department's associated obligations and operations, and many other events that may materially affect the realized or projected financial performance of the Power Charge Accounts or the Bond Charge Accounts. In such event, the Department will inform the Commission of such material changes and will revise its revenue requirements accordingly. Several relevant factors are discussed in more detail within Section D.

B. BACKGROUND

THE ACT AND THE RATE AGREEMENT

Information on the Act and the Rate Agreement, which have not changed since 2002, is contained in the Department's prior Determinations of Revenue Requirements, copies of which have been incorporated into the administrative record supporting this Determination.

PROCEEDINGS RELATING TO 2008

On July 20, 2007, the Department issued its Proposed Determination of Revenue Requirements for 2008, consistent with the requirements of Sections 80110 and 80134 of the California Water Code, and provided information consistent with the Regulations. The Department provided interested persons with quantitative results from its PROMOD market simulation and Financial Model, subject to applicable non-disclosure requirements. Interested persons were advised to submit comments no later than August 10, 2007. The Department included a summary of the comments and its responses in Section I of the 2008 Determination dated August 22, 2007.

On August 22, 2007, the Department published its Determination of Revenue Requirements for the period of January 1, 2008 through and including December 31, 2008 and submitted it to the Commission. The August 22, 2007 Determination was found to be just and reasonable based on an assessment of all comments, the administrative record, the Act, the Regulations, Bond Indenture requirements and the Rate Agreement.

The Department reviewed certain matters relating to its August 22, 2007 Determination, including, but not limited to, operating results of the Electric Power Fund (the "Fund") as of September 30, 2007 (the August 22, 2007 Determination incorporated preliminary actual operating results through June 2007) and an updated gas price forecast.

On October 10, 2007, the Department issued its Proposed Revised Determination of Revenue Requirements for 2008, consistent with the requirements of Sections 80110 and 80134 of the California Water Code, and provided information consistent with the Regulations. The Department provided interested persons with quantitative results from its PROMOD market simulation and Financial Model, subject to applicable non-disclosure requirements. Interested persons were advised to submit comments no later than October 24, 2007. The Department included a summary of the comments and its responses in Section I of the 2008 Revised Determination.

On October 31, 2007, the Department published its Revised Determination of Revenue Requirements for the period of January 1, 2008 through and including December 31, 2008 and submitted it to the Commission. The Revised Determination was found to be just and reasonable based on an assessment of all comments, the administrative record, the Act, the Regulations, Bond Indenture requirements and the Rate Agreement.

On December 20, 2007, the Commission issued Decision 07-12-030: "Order Allocating the 2008 Revenue Requirement Determination of the California Department of Water Resources".

The Department reviewed certain matters relating to its October 31, 2007 Determination, including, but not limited to, the restructuring of the Department's long-term power contract with Calpine Energy Services, L.P formerly referred to as the "Long-Term Commodity Sale" transaction, also known as the "Calpine 2" contract. The restructuring culminated in a contract amendment which was entered into on December 7, 2007, that replaced 1000 MW of 7x24 energy deliveries through 2009 with a 180 MW unit-contingent dispatchable capacity during 2008 and 2009, with an extension option by DWR through 2012.

On December 27, 2007, the Department issued its Proposed Supplemental Determination of Revenue Requirements for 2008, consistent with the requirements of Sections 80110 and 80134 of the California Water Code, and provided information consistent with the Regulations. The Department provided interested persons with quantitative results from its PROMOD market simulation and Financial Model, subject to applicable non-disclosure requirements. Interested persons were advised to submit comments no later than January 17, 2008. The Department included a summary of the comments and its responses in Section I of the 2008 Supplemental Determination.

On February 15, 2008, the Department published its Supplemental 2008 Determination of Revenue Requirements for the period of January 1, 2008 through and including December 31, 2008 and submitted it to the Commission. The Supplemental 2008 Determination resulted in a total decrease in cost of $630 million compared to the October 31, 2007 Determination.

The Commission found that the Supplemental Determination was just and reasonable based on an assessment of all comments, the administrative record, the Act, the Regulations, Bond Indenture requirements and the Rate Agreement.

THE 2009 DETERMINATION

The Department sent requests for information to each IOU on April 14, 2008, which solicited an update of various modeling assumptions and operational considerations. During April and May, the Department received responses to its requests for information from the IOUs.

The information obtained from the IOUs served as the basis for the Department's analytical and forecasting efforts related to the Proposed 2009 Determination published on July 8, 2008. The Department also considered other important criteria, including, but not limited to, Commission

Decisions and Bond Indenture requirements. The Department incorporated the resulting data into the PROMOD IV market simulation model, and the data became a part of the projections leading to the Proposed Determination. The Department provided interested persons with quantitative results from its PROMOD market simulation and Financial Model, subject to applicable non-disclosure requirements. Interested parties were advised to submit comments no later than July 29, 2008.

PG&E and SCE submitted comments. The Department considered the comments prior to this 2009 Determination. A summary of the comments and the Department's responses are included in Section I.

After review of all comments, the Department has made the following changes in this 2009 Determination:

1. Corrected a data reporting error that under-stated the variable cost of the Iberdrola Renewables contract. As a result, contract costs are higher than those projected in the Proposed 2009 Determination. The higher contract costs increased the Department's Operating Reserve and Operating Account requirements for the 2009 Revenue Requirement Period.

2. PG&E's most recent estimate of transmission and distribution losses and unaccounted for energy, which was provided to the Department in PG&E's response to the 2009 Revenue Requirement Data Requests, is included in this Determination.

3. Based on market observations, the Department has updated the natural gas price forecast supporting its contract costs for the remainder of 2008. The update to the 2008 gas price forecast results in gas prices that are approximately $3/MMBtu lower than the forecast previously used to project the Department's cost for the remainder of 2008. The lower gas prices affect this 2009 Determination by increasing the projected January 1, 2009 power charge account balances.

Table B-1 summarizes the changes between the Proposed Determination and this 2009 Determination for the Power Charge revenue requirement and Power Charge Accounts. Table B-1 reports the Department's operating activity on a cash basis; therefore, operating activity occurring in December 2008 affects the projected cash flow in 2009.

There are no changes to the 2009 Determination for the Bond Charge revenue requirements and Bond Charge Accounts.

TABLE B-1
SUMMARY OF THE DEPARTMENT'S 2009 POWER CHARGE REVENUE REQUIREMENTS AND POWER CHARGE ACCOUNTS AND COMPARISON TO PROPOSED DETERMINATION[1]
($ Millions)

Line	Description	2009[2]	Proposed 2009 Determination	Difference
1	*Beginning Balance in Power Charge Accounts*			
2	Operating Account	930	808	121
3	Priority Contract Account	-	-	-
4	Operating Reserve Account	548	548	-
5	**Total Beginning Balance in Power Charge Accounts**	**1,478**	**1,356**	**121**
6	*Power Charge Accounts Operating Revenues*			-
7	Power Charge Revenues[3]	4,060	4,164	(103)
8	Other Revenue[4]	70	71	(1)
9	Interest Earnings on Fund Balances	42	39	3
10	**Total Power Charge Accounts Operating Revenues**	**4,172**	**4,274**	**(102)**
11	*Power Charge Accounts Operating Expenses*			-
12	Administrative and General Expenses	28	28	-
13	Total Power Costs[5]	4,205	4,155	50
14	**Total Power Charge Accounts Operating Expenses**	**4,232**	**4,182**	**50**
15	Net Operating Revenues	(60)	92	(151)
16	**Ending Aggregate Balance in Power Charge Accounts**	**1,418**	**1,448**	**(30)**

Target Minimum Power Charge Account Balances	Target (Millions of Dollars)		
Operating Account: This minimum balance is targeted to cover intra-month volatility as measured by the maximum difference in revenues and expenses in a calendar month.	425	397	28
Operating Reserve Account: Covers deficiencies in the Operating Account. It is sized as the greater of (i) the maximum seven-month difference between operating revenues and expenses as calculated under a stress scenario, (ii) 12% of the Department's annual operating expenses and (iii) an amount equal to the maximum projected monthly contract cost payments.	667	639	27
Total Operating Reserves:	1,091	1,037	55

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]Includes Bundled customer revenues and Cost Responsibility Surcharge revenues, whether from Direct Access or other sources, such as Community Choice Aggregation.
[4]Other revenues received by the Department are those related to surplus energy sales conducted by the IOUs when the IOUs and the Department have procured more energy than is needed to serve retail customers; details related to surplus energy sales are further discussed in Section D.
[5]Includes gas hedging and collateral amounts.

C. THE DEPARTMENT'S DETERMINATION OF REVENUE REQUIREMENTS FOR THE PERIOD JANUARY 1, 2009 THROUGH DECEMBER 31, 2009

REVENUE REQUIREMENT DETERMINATION

For 2009, the Department's revenue requirements consist of Department Costs and Bond Related Costs, which are to be satisfied primarily by Power Charge Revenues and Bond Charge Revenues, respectively.

During 2009, the Department projects that it will incur the following power procurement-related Costs: (a) $4.205 billion for long-term power contract purchases to cover the net short requirement of customers; (b) $28 million in administrative and general expenses; and (c) $(60) million in other net changes to Power Charge Accounts (including operating reserves). This projection results in a revenue requirement of $4.172 billion.

Funds to meet these costs (in addition to surplus operating reserves) are projected to be provided from (a) $70 million from the Department's share of surplus power sales revenues; (b) $42 million of interest earned on Power Charge Account balances; and (c) $4.060 billion from Power Charge Revenues and Cost Responsibility Surcharge ("CRS") revenues from customers other than customers of the IOUs and DWR.

Table C-1 provides a quarterly projection of costs and revenues associated with the Power Charge Accounts for the 2009 Revenue Requirement Period.

TABLE C-1
POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE:
RETAIL CUSTOMER POWER CHARGE CASH REQUIREMENT
($ Millions)

Line	Description	Amounts for Revenue Requirement Period				
		2009 - Q1	2009 - Q2	2009 - Q3	2009 - Q4	Total
0	*Power Charge Accounts Expenses*					-
1	Power Costs	1,039	964	1,153	1,048	4,205
2	Administrative and General Expenses	7	7	7	7	28
3	Net Changes to Power Charge Account Balances	(87)	30	(44)	41	(60)
4	**Total Power Charge Accounts Expenses**	**959**	**1,001**	**1,117**	**1,096**	**4,172**
5	*Power Charge Accounts Revenues*					
6	Other Power Sales Revenues	14	34	10	11	70
7	Interest Earnings on Power Charge Account Balances	11	10	10	10	42
8	Operating Account Balance Adjustment	-	-	-	-	-
9	Total Power Charge Revenue Requirement	934	956	1,096	1,074	4,060
10	**Total Power Charge Accounts Revenues**	**959**	**1,001**	**1,117**	**1,096**	**4,172**

During 2009, the Department projects that it will incur the following Bond Related Costs: (a) $920 million for debt service on the Bonds and related Qualified Swap payments, payments of credit enhancement and liquidity facilities charges, and costs relating to other financial instruments and servicing arrangements in connection with the Bonds, and (b) $(33) million for changes to Bond Charge Account balances, resulting in total Bond Charge Account expenses of $887 million.

Funds to meet these requirements are provided from (a) $58 million in interest earned on Bond Charge Account balances, and (b) $829 million from Bond Charge Revenues (including CRS revenues from customers other than customers of the IOUs and DWR). There are no projected net transfers from Power Charge Accounts.

Table C-2 provides a quarterly projection of costs and revenues relating to the Bond Charge Accounts for the 2009 Revenue Requirement Period.

TABLE C-2
POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE:
RETAIL CUSTOMER BOND CHARGE CASH REQUIREMENT
($ Millions)

Line	Description	Amounts for Revenue Requirement Period				
		2009 - Q1	2009 - Q2	2009 - Q3	2009 - Q4	Total
0	*Bond Charge Accounts Expenses*					
1	Debt Service Payments	55	657	55	152	920
2	Net Changes to Bond Charge Account Balances	148	(444)	180	83	(33)
3	**Total Bond Charge Accounts Expenses**	**203**	**214**	**235**	**235**	**887**
4	*Bond Charge Accounts Revenues*					
5	Interest Earnings on Bond Charge Account Balances	9	21	8	19	58
6	Retail Customer Bond Charge Revenue Requirement	194	193	227	216	829
7	**Total Bond Charge Accounts Revenues**	**203**	**214**	**235**	**235**	**887**

In aggregate, the Department's total cash basis expenses are projected to be $5.152 billion. Revenues from interest earned and other power sales are projected to be $170 million, and net changes in fund balances are projected to be $(92) million, resulting in combined customer revenue requirements of $4.890 billion.

D. ASSUMPTIONS GOVERNING THE DEPARTMENT'S PROJECTION OF REVENUE REQUIREMENTS FOR THE 2009 REVENUE REQUIREMENT PERIOD

The Department based this 2009 Determination on a number of assumptions regarding retail customer load, demand side management and conservation, power supply, natural gas prices, off-system sales, administrative and general expenses as well as other considerations affecting the Department's revenues and expenses.

ESTIMATED ENERGY REQUIREMENTS

The Department obtained the utilities' most recent retail energy forecasts in April 2008. The Department reviewed the utilities' underlying forecast assumptions, including population growth, changes in employment and labor within the utility's service area, weather effects, growth in distributed generation, and annexation of the utility's service area by publicly owned utilities. In developing its bundled requirements forecast, the Department also reviewed forecasts of direct access and Community Choice Aggregation (CCA) in California. These assumptions are discussed in greater detail below.

Table D-1 shows the projected 2009 energy requirements forecast (quantified in gigawatt hours) for the PG&E, SCE and SDG&E service areas during 2009.

TABLE D-1
ESTIMATED ANNUAL ENERGY REQUIREMENTS

Service Area	Total Retail Requirements	Direct Access and CCA Requirements	Bundled Requirements
Pacific Gas & Electric	95,655	7,330	88,324
Southern California Edison	97,903	10,430	87,473
San Diego Gas & Electric	22,373	3,277	19,096
Total	215,931	21,037	194,894

DIRECT ACCESS

The Department's direct access estimates are based on data provided by each IOU in April and May 2008 and a review of monthly direct access reports produced by the Commission. The Department notes a slow but steady decline in direct access loads since the Commission suspended the right of bundled customers to elect direct access service, effective September 20, 2001. The Department regularly reviews each utility's monthly report to the Commission on current direct access load and service request changes to identify any substantive developments that would require action by the Department.

While the option to elect direct access service is suspended until the Department no longer supplies power under Division 27 of the Water Code (see California Water Code § 80110), the Commission recently initiated a Rulemaking (R. 07-05-025) to evaluate lifting the suspension of direct access prior to 2015 when the last long-term contract expires[3]. The Commission states that it expects the proceeding to last longer than eighteen months. Given the manifold issues and the timing of the proceeding, the Department does not project that the suspension of direct access will be lifted during the 2009 Revenue Requirement period.

Table D-2 shows each IOU's direct access forecast, as a percentage of total retail loads, for 2009.

TABLE D-2
2009 DIRECT ACCESS FORECAST[4]

Service Area	Percent of Retail Load
Pacific Gas & Electric	6.92%
Southern California Edison	10.49%
San Diego Gas & Electric	14.65%
Total	**9.34%**

COMMUNITY CHOICE AGGREGATION

CCA refers to the ability of communities or public entities to aggregate load and procure all or a portion of their power requirements independent of the IOUs. Assembly Bill 117, adopted in 2002, modified the Public Utilities Code to allow local governments "…to elect to combine the loads of its residents, businesses, and municipal facilities in a community-wide electric buyers' program."[5] Significant volumes of CCA could lead to changes in Department rates to accommodate reduced IOU retail deliveries of Department power.

At present no load has left bundled utility service to form or become part of a Community Choice Aggregator pursuant to AB 117. However, the San Joaquin Valley Power Authority (SJVPA) filed an Implementation Plan with the CPUC in January 2007 to become a Community Choice Aggregator. That plan was certified by the CPUC in May 2007. At the present time, SJVPA is expected to eventually serve approximately 2,000 GWh of load to eleven cities and one county. SJVPA's plans to phase in its Community Choice Aggregation program have been delayed and are not expected to result in power procurement for customers prior to November 2008. As a result of these delays, SJVPA is currently expected to phase in approximately 800 GWh of load in 2009, with additional load served in 2010. The SJVPA Community Choice Aggregation load, if implemented, will reduce bundled load in both PG&E's service territory and SCE's service territory.

Other communities have indicated an interest in pursuing CCA, including the City and County of San Francisco, several East Bay cities, the City of Chula Vista, Marin County, and the City of Fresno. Because the Department estimates that the process for aggregators to initiate feasibility studies and ultimately procure power on behalf of load to be eighteen to twenty-four months, we

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[3] Peevey Proposed Decision April 24, 2007, Order Granting Petition for Rulemaking and Instituting Rulemaking as to Whether, When, or How Direct Access Should be Restored.
[4] Figures in Table D-2 represent direct access as a percentage of total retail loads for 2009. These percentages correspond to direct access loads forecast by the IOUs in 2008. The Department assumes that direct access load will remain constant from 2009 to 2010.
[5] Public Utilities Code, Section 331.1(a).

do not expect any load from these communities to migrate under the CCA program during the 2009 Revenue Requirement Period.

POWER SUPPLY RELATED ASSUMPTIONS

In this 2009 Determination, the Department considered three types of power supplies needed to meet the requirements of each IOU: (a) IOU supplied resources; (b) supply from the Department's long-term power contracts; and (c) the residual net short of each IOU.[6]

Table D-3 below shows, for the 2009 Revenue Requirement Period, the estimated energy requirements for the customers of the IOUs, estimated supplies from generation by the three IOUs,[7] the resulting net short, the expected supply from the Department's long-term power contracts, off-system energy sales and the residual net short.

TABLE D-3
ESTIMATED NET SHORT ENERGY, SUPPLY FROM THE DEPARTMENT'S LONG-TERM POWER CONTRACTS AND THE DEPARTMENT'S ESTIMATE OF THE RESIDUAL NET SHORT

	Amount for the Revenue Requirement Period (GWH)
All Investor-Owned Utilities	
Energy Requirements After Adjustments	185,096
Supply from Utility Resources	125,400
Net Short	59,696
Supply from the Department's Priority Long-Term Power Contracts	42,970
Off-System Sales	(3,679)
Residual Net Short (Surplus)	20,405

Table D-4 shows, on a quarterly basis for the 2009 Revenue Requirement Period, estimated net short volumes in gigawatt-hours, supply from the Department's long-term power contracts and the residual net short.

[6] While the Department has calculated and presented the residual net short requirements of the IOUs, pursuant to the Act, the Department has not made any provision for the cost of the residual net short requirements in its Determination for the 2009 Revenue Requirement Period. For purposes of this 2009 Determination, the residual net short for each IOU equals the projected amount of wholesale energy remaining to be procured by such IOU on behalf of ratepayers in its service area.

[7] For purposes of this 2009 Determination, generation retained by the three IOUs is defined as the sum of generation owned by the IOUs, interruptible load, supply from contracts between the IOUs and qualifying facilities ("QFs") and other bilateral contracts.

TABLE D-4
NET SHORT, SUPPLY FROM THE DEPARTMENT'S LONG-TERM POWER CONTRACTS, OFF-SYSTEM SALES AND RESIDUAL NET SHORT IN 2009[1]

	Net Short (GWH)	Supply from Power Contracts (GWH)	Power Contract Costs (Millions of Dollars)	Off-System Sales Volumes (GWH)	Revenues from Off System Sales (Millions of Dollars)	(Residual Net Short) Spot Volume (GWH)
Q1-2009	15,009	10,512	1,152	(941)	(73)	5,439
Q2-2009	11,959	10,319	1,031	(1,887)	(115)	3,527
Q3-2009	16,641	11,632	1,228	(389)	(24)	5,397
Q4-2009	16,088	10,507	1,075	(461)	(42)	6,042
Total	59,696	42,970	4,486	(3,679)	(253)	20,405

[1]All costs and revenues are presented on an accrual basis.

UTILITY RESOURCES

The Department reviewed each utility's 2009 forecast of utility owned generation, qualifying facility ("QF") contract generation, and bilateral contract generation for consistency with the Department's own energy dispatch forecast. Where necessary, the Department updated its assumptions concerning QF contract terms and expiration dates, outage schedules, and net dependable resource capacity, among others, to reflect current details related to each IOU's resource portfolio.

HYDRO CONDITION ASSUMPTIONS

Normal hydrologic conditions are assumed for both California and the Pacific Northwest during 2009 and 2010. Neither the CEC nor the National Weather Service Northwest River Forecast Center has provided meaningful forecasts past the 2008 water year. Therefore, DWR has projected normal hydroelectric dispatch for the 2009 Revenue Requirement Period.

CONTRACT ASSUMPTIONS

During the 2009 Revenue Requirement Period, approximately 42,970 GWhs of energy is projected to be supplied on behalf of the retail electric customers of the IOUs through the Department's long-term power contracts. The terms and conditions of each contract have been reflected in the Department's market simulation, resulting in a projection of contract-specific, hourly energy dispatches to meet the projected energy requirements of each IOU's retail customers. The terms and conditions incorporated in the Department's market simulation include, among other details, must-take energy volumes and dispatchable contract capacities, contract heat rates and unit outage rates as well as scheduling limitations. During market simulation, all energy dispatches from the Department's dispatchable long-term power contracts occur based on dispatch of available power supply resources in merit order of the cost of dispatch and delivery of those resources, subject to transmission delivery constraints, and the effective cost of those constraints. In general, each incremental generating unit is dispatched only if the incremental cost of generating an additional MWh from that unit is less than the cost of alternative sources that can provide to the same location.

Table D-5 provides a listing of all of the long-term power contracts that will be operational during the 2009 Revenue Requirement Period and beyond, describing the term and capacity associated with each contract and the IOU to which the contract has been allocated.

Detailed contract terms can be found on the CERS website, http://cers.water.ca.gov

TABLE D-5
LONG-TERM POWER CONTRACT LISTING

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
Alliance Colton, LLC	4/23/2001 Renegotiated on 9/19/02	8/1/2001	12/31/2010	80	SCE
Bear Energy (Previously Williams Energy)	2/16/2001 Renegotiated on 11/11/02	1/1/2008	12/31/2010	275	SDG&E
"	"	7/1/2003	12/31/2010	50	SDG&E
"	"	1/1/2008	12/31/2010	1045	SCE
CalPeak Power—Panoche, LLC	8/14/2001 Renegotiated on 5/2/02	12/27/2001	12/27/2011	52.6	PG&E
CalPeak Power--Vaca Dixon, LLC	8/14/2001 Renegotiated on 5/2/02	6/21/2002	12/31/2011	51.9	PG&E
CalPeak Power--El Cajon, LLC	8/14/2001 Renegotiated on 5/2/02	5/29/2002	12/31/2011	50.9	SDG&E
CalPeak Power—Border, LLC	8/14/2001 Renegotiated on 5/2/02	12/12/2001	12/12/2011	51.6	SDG&E
CalPeak Power—Enterprise, LLC	8/14/2001 Renegotiated on 5/2/02	12/8/2001	12/8/2011	52.5	SDG&E
Calpine Energy Services, L.P. (Calpine 1)	2/6/2001 Renegotiated on 4/22/02	1/1/2004	12/31/2009	1000	PG&E

		Delivery	Delivery		
	Date	Start	End	Capacity	
Counter-Party	**Executed**	**Date**	**Date**	**MW**	**Allocated**
Calpine Energy Services, L.P. (Calpine 2)	2/26/2001 Renegotiated on 4/22/02; Renegotiated on 12/7/2007	1/1/2008	12/31/2009, buyer option to extend to 12/31/2012	180	PG&E
Calpine Energy Services, L.P. (Peaking Capacity)	2/27/2001 Renegotiated on 4/22/02	8/1/2002	7/31/2011	495	PG&E
Coral Power, LLC	5/24/2001	1/1/2006	6/30/2010	400	PG&E
"	"	7/1/2010	6/30/2012	100	PG&E
"	"	7/1/2002	6/30/2012	100	PG&E
"	"	7/1/2003	6/30/2012	175	PG&E
"	"	7/1/2004	6/30/2012	175	PG&E
Power Receivables Finance (formerly Allegheny Energy Supply Company, LLC)	3/23/2001 Renegotiated 6/10/03	1/1/2006	12/31/2011	800	SCE
GWF Energy, LLC	5/11/2001 Renegotiated on 8/22/02	9/6/2001	12/31/2011	95.8	PG&E
"	"	7/1/2002	12/31/2011	95.8	PG&E
"	"	6/01/2003	10/31/2012	170.5	PG&E
High Desert Power Project	3/9/2001 Renegotiated on 4/22/02	4/22/2003	3/31/2011	Up to 840	SCE
Kings River Conservation District	12/31/2002 Renegotiated 8/18/04	9/19/2005	9/18/2015	96	PG&E
Mountain View Power Partners, LLC	5/31/2001 Renegotiated on 10/1/02	10/1/2001	9/30/2011	66.6	SCE

		Delivery	Delivery		
	Date	Start	End	Capacity	
Counter-Party	**Executed**	**Date**	**Date**	**MW**	**Allocated**
Iberdrola Renewables (formerly PPM Energy)	7/6/2001	7/1/2004	6/30/2011	300	PG&E
City/County of San Francisco	12/30/2002	unknown	unknown	Est. 192	PG&E
Sempra Energy Resources	5/4/2001	1/1/2004	9/30/2011	1200	SCE
"	"	1/1/2008	9/30/2011	400	SCE
Sunrise Power Company, LLC	6/25/2001 Renegotiated on 12/31/02	6/01/2003	6/30/2012	572	SDG&E
(Wellhead) Fresno Cogeneration Partners	8/3/2001 Renegotiated on 12/17/02	8/20/2001	10/31/2011	21.5	PG&E
Wellhead Power Gates, LLC	8/14/2001 Renegotiated on 12/17/02	12/27/2001	10/31/2011	46.4	PG&E
Wellhead Power Panoche, LLC	8/14/2001 Renegotiated on 12/17/02	12/14/2001	10/31/2011	49.9	PG&E
Shell Wind (Cabazon Project)	7/12/2001 Renegotiated on 4/24/02	8/31/2002	12/31/2013	43	SDG&E
Shell Wind (Whitewater Hill Project)	7/12/2001 Renegotiated on 4/24/02	8/31/02 (partial)	12/31/2013	65	SDG&E

The Department, in cooperation with representatives of the Attorney General's office and representatives of the Governor's staff, has continued its efforts to modify terms and conditions of the Department's long-term power contracts consistent with the requirements of the Act and applicable federal law. Three of the remaining original contracts have yet to be renegotiated from their original terms.

CONTRACT MANAGEMENT AND DISPOSITION ALTERNATIVES

The Power Charge component of the revenue requirement is directly related to the costs of power supplied under the Department's long-term power contracts. In considering changes to the contracts to modify its revenue requirements, the Department can (1) continue to use its contracts in their present form, (2) seek to modify the contracts through bilateral renegotiation with its counterparties, or (3) terminate the contracts.

Theoretically, the Department could unilaterally terminate one or more of its contracts. The terms of each of the Department's contracts provide that if the contract is terminated for reasons other than breach or default by the power-supplying counterparty to the contract, the Department is obligated to pay the entire remaining estimated value of the contract. Any such termination other than for an uncured default or breach by the seller would likely increase the Department's revenue requirements due to timing implications of the payments to the counterparty. In addition, energy no longer supplied by DWR would need to be replaced by the investor-owned utilities in either the short-term market or through new long-term power contracts with other suppliers, to the extent any portion of the energy supplied under a DWR contract is not surplus to the energy needs of the retail customers of the utilities. For this reason, under present market conditions and terms of the contracts, the Department does not believe that unilateral termination of any of the contracts would result in a reduction in its revenue requirements or overall ratepayer costs.

It is possible that additional power contract modifications, including termination of one or more contracts, could be agreed to between the Department and one or more of its long-term power supply counterparties prior to the end of the 2009 Revenue Requirement Period. As of the date of filing of this 2009 Revenue Requirement Determination, the Department has not entered into any such final power contract modifications other than as already noted herein.

COST RESPONSIBILITY SURCHARGE

In a series of decisions, the CPUC ordered certain classes of direct access, municipal and customer generation departing load, and Community Choice Aggregation customers to pay the Cost Responsibility Surcharge related to historical stranded costs and ongoing costs. Included in the Cost Responsibility Surcharge is a DWR Bond Charge component, which is assessed to pay debt service associated with DWR's bond issuances and a DWR Power Charge component, which pays a portion of the above-market costs of the DWR power portfolio. The Bond Charge and the Power Charge components are rates imposed on total electricity usage by direct access, departing load and Community Choice Aggregation customers by the CPUC in concert with the establishment of Power Charges and Bond Charges on bundled customers.

Cost Responsibility Surcharge revenues reduce the amount of Bond Charges and Power Charges that must be imposed on bundled customers to recover Bond Related Costs and Department Costs. In the aggregate, the payments by direct access load, departing load, and Community Choice Aggregation load and from bundled customer load for the DWR Bond Charge and the DWR Power Charge flow to DWR to recover the DWR Bond Related Costs and Department Costs.

SALES OF EXCESS ENERGY ASSUMPTIONS[8]

As with any retail provider of energy, from time to time, the combined IOU and Department power supply portfolios provide more energy than is needed to serve their retail customers. In general, these additional purchases result from differences between projected and actual IOU load. This excess energy is sold in wholesale markets by the IOUs under the current operating arrangements governing administration, operation and dispatch of DWR's contracts. On occasion, the price obtained for surplus power sales will be less than the price paid for power. However, these minimal energy transaction losses are an expected incident of appropriate power supply portfolio management, in that losses on sales from over-procurement are on average less than the costs associated with spot market purchases when there has been under-procurement. The income from such sales is used to partially offset the revenue requirements of the Department and the IOUs that would otherwise be recovered from retail customers.

On September 19, 2002, the Commission issued Decision 02-09-053, which, in part, determined that energy and resulting income from the sale of excess energy ("off-system sales") would be shared on a pro-rata basis between the Department and the IOUs.

Projected revenue shares from the sale of excess energy, both the Department's and total IOU, are provided below in Table D-6.

TABLE D-6
PROJECTED SALE OF EXCESS ENERGY[1]

	DWR Volume	**IOU Volume**	**Total Volume**		**DWR Revenue**	**IOU Revenue**	**Total Revenue**		**Weighted Average Price**
	(GWh)	(GWh)	(GWh)		(Millions of Dollars)	(Millions of Dollars)	(Millions of Dollars)		($/MWh)
Q1-2009	275	666	941		21	51	73		77
Q2-2009	508	1,379	1,887		31	84	115		61
Q3-2009	104	284	389		6	17	24		61
Q4-2009	140	321	461		13	29	42		91
Total	1,027	2,651	3,679		72	182	253		69

[1]All revenues presented on an accrual basis

LONG-TERM POWER CONTRACT COST ASSUMPTIONS

Each long-term power contract identified in Table D-5 has been reviewed by the Department to determine the costs that will impact its revenue requirements during 2009. All applicable costs are reflected in the Department's electric market simulation along with previously noted operational considerations. The types of costs included in the Department's contract-specific projections include, but are not limited to, fixed energy, capacity, fixed operation and maintenance, variable operation and maintenance, scheduling coordinator fees, and fuel management fees. Total accrued long-term power contract costs, including requisite natural gas

[8] The Department is considering the affects of eliminating the sharing of surplus sales revenue on its Revenue Requirements

purchases, are projected to be $4.486 billion for the 2009 Revenue Requirement Period, as noted in Table D-4. Natural gas costs represent a significant component of the Department's total energy costs and are discussed below in greater detail.

For informational purposes, Table D-7 shows, for the 2009 Revenue Requirement Period, the expected average cost (in $/MWh) on a quarterly basis for the Department's long-term power contracts.

TABLE D-7
ESTIMATED POWER SUPPLY COSTS
(Dollars per Megawatt-Hour)

	Long-Term Priority Contracts
Quarter 1 – 2009	107
Quarter 2 – 2009	97
Quarter 3 – 2009	102
Quarter 4 – 2009	99

NATURAL GAS PRICE FORECAST AND FUELS ASSUMPTIONS

The natural gas price forecast supporting this 2009 Determination is based on the NCI Spring 2008 Natural Gas Price Forecast ("NCI Spring 2008 Forecast") Base Case prepared by Navigant Consulting, Inc. ("NCI"), consultants to the Department. Assumptions underlying the NCI Spring 2008 Forecast include all significant supply and demand factors affecting the North American natural gas market such as the timing of major gas pipeline capacity changes, resource base additions and subtractions, gas demand, the price of crude oil, the timing and magnitude of certain liquefied natural gas ("LNG") capacities, imports and exports.

The NCI Spring 2008 Forecast was prepared based upon the GPCM natural gas forecast model and yields long term monthly gas prices. In order to account for short term fluctuations in the natural gas market, NYMEX prices are used in the initial eighteen months of the forecast. For the gas price forecast underlying this 2009 Determination, the near term monthly prices at Henry Hub were revised on June 25, 2008 by averaging the then ten most recent daily settlement prices. The differences between the initial monthly price forecasts at Henry Hub and the recalculated monthly prices were used to proportionately adjust the forecasted prices at other market hubs, including PG&E Citygate and the Southern California Border. The results of these adjustments to the NCI Fall 2007 Forecast are referred to as the NCI/DWR Spring 2008 Natural Gas Forecast ("NCI/DWR Spring 2008 Forecast").

Compared to the Base Case forecast underlying the Supplemental 2008 Determination published February 15, 2008, prices in the NCI/DWR Spring 2008 Forecast Base Case supporting this 2009 Determination are shown in Table D-8.

TABLE D-8
NATURAL GAS PRICE FORECAST COMPARISON AT HENRY HUB
(Nominal $/MMBtu)

	2009	**2010**
Gas Price Forecast –2009 Determination	12.06	10.02
Gas Price Forecast – 2008 Supplemental Determination	7.98	NA
Difference	4.09	NA

Table D-9 below lists the updated natural gas prices by quarter for 2009 and 2010 at two key California market hubs: PG&E Citygate and the Southern California Border.

TABLE D-9
NATURAL GAS AVERAGE PRICE FORECASTS
(Nominal $/MMBtu)

	Southern California Border		**PG&E Citygate**	
	2009	**2010**	**2009**	**2010**
Q1 – 2009	13.30	11.87	13.82	12.62
Q2 – 2009	10.70	9.74	11.21	10.38
Q3 – 2009	10.99	9.22	11.56	9.79
Q4 – 2009	11.47	8.00	12.24	8.53
Annual Average	**11.61**	**9.71**	**12.21**	**10.33**

As part of a 2002 settlement agreement with Williams Energy Marketing and Trading ("Williams") the Department entered into a Natural Gas Purchase Contract for natural gas deliveries beginning on January 1, 2004 and ending on December 31, 2010. On October 2, 2003, the CPUC issued Decision 03-10-016, which allocated fuel volumes related to the Williams Natural Gas Purchase Contract between SCE (64% in 2009) and SDG&E (36% in 2009).

During the 2009 Revenue Requirement Period, it is projected that the Natural Gas Purchase Contract will result in power cost savings of approximately $131 million, based on the difference between the contract fuel price of $4.32 and the Department's projected average fuel price of $11.61 at the Southern California Border pricing hub. For the purpose of determining power cost savings related hereto, the weighted average fuel price considered in this analysis accounts for related, seasonal variations in both the base case fuel price forecast and fuel volumes delivered under the Williams Natural Gas Purchase Contract in 2009.

GAS HEDGING EXPENSE

For the 2009 Revenue Requirement Period, the Department has reflected the impact of natural gas price hedges on a portion of the projected gas purchases that will be made to support the Department's power contracts. The hedging expenses and projected hedged volume are based on responses to information requests provided by the IOUs in April and May 2008 and monthly activity in the Department's Gas Hedging Account and the Department's own internal analysis.

The Department estimates that as of June 30, 2008, the IOUs had collectively secured, or developed reasonably firm plans to secure, hedges on behalf of DWR that establish the effective price for over 111 million MMBtu during calendar year 2009. The hedged volume represents approximately 58 percent of total projected IOU base case gas requirements (for fuel related to allocated DWR power contracts) for the 2009 Revenue Requirement Period. The Department has effectively hedged 18 million MMBtu of natural gas via firm price deliveries from the Williams contract during both the 2009 and 2010 Revenue Requirement Periods, and this annual volume is included in the aforementioned 111 million MMBtu for 2009.

CALIFORNIA INDEPENDENT SYSTEM OPERATOR MARKET REDESIGN AND TECHNOLOGY UPGRADE ASSUMPTIONS

The Department's 2009 Revenue Requirement was developed using the same fundamental economic dispatch principles used in past revenue requirements. The CAISO currently expects to implement their Market Redesign and Technology Upgrade ("MRTU") in February 2009. Some uncertainty exists with respect to quantifying the effects of the Locational Market Price ("LMP") provisions of MRTU on the revenue from off-system sales of excess DWR energy, and the IOUs' congestion costs associated with delivery of market contracts held by DWR.

While there may be some increased price volatility in off-system sale prices after implementation of LMP under MRTU, the reduced projected contribution of off-system sales in future years reduces the effect of this volatility on overall DWR revenue requirement levels. Congestion costs related to delivery of DWR contract energy are anticipated to be paid by the IOUs. DWR is engaged in discussions with each IOU to align dispatch assumptions to assure the power charge revenue stream, and to help reduce the uncertainty of IOU exposure to congestion costs in their separate revenue requirements. The implementation of MRTU does not impact the Bond Charge.

Currently, all of the Department's power is provided through bilateral trades. When MRTU is implemented, some DWR power may be delivered through the CAISO markets. The underlying assumption for this Revenue Requirement is that the Commission will direct the IOUs to continue remitting to DWR at the remittance rate on all DWR contract energy delivered to IOU bundled customers, since the energy benefits the retail customers. Any energy in excess of bundled customer load would become a surplus sale with the energy and revenues being shared by the IOU and DWR based on the pro-rata sharing ordered in CPUC Decision D.02-09-053.

ADMINISTRATIVE AND GENERAL COSTS

The Department's administrative and general costs of $28 million consist of $24 million for appropriated budget expenditures including funds for labor and benefits, pro rata charges for services provided to the power supply program by other State agencies and $4 million for consulting services for development and monitoring of the revenue requirements, litigation and dispute resolution support, power contract management, and financial advisory services for managing the $10 billion debt portfolio and related reserves.

FINANCING RELATED ASSUMPTIONS

For purposes of calculating the interest earnings on account balances during 2009, the Department assumes a 3.97 percent earnings rate for the Debt Service Reserve Account and a 2.8 percent earnings rate for all other accounts during the 2009 Revenue Requirement Period.

The Department currently has $4.111 billion of fixed rate bonds outstanding, $3.939 billion of hedged variable rate bonds outstanding that have corresponding interest rate hedges in place to convert debt service to fixed rate and $1.475 billion of unhedged variable rate debt. The projected average interest rate for all fixed rate bonds for the 2008 Revenue Requirement Period is 5.188 percent. The projected average interest rate for all hedged variable rate bonds (taking into account the hedges) is 3.351 percent.

For purposes of calculating the interest accruing on unhedged variable rate bonds during 2009, as well as any future revenue requirement periods, in accordance with the Bond Indenture, interest is assumed to accrue at a rate equal to the greater of (a) 130 percent of the highest average interest rate on such Variable Rate Bonds in any calendar month during the twelve (12) calendar months ending with the month preceding the date of calculation, or such shorter period that such Variable Rate Bonds shall have been Outstanding, or (b) 4.0 percent. For the 2009 Revenue Requirement Period, on the basis of these assumptions, the interest rate on Variable Rate Bonds is projected to be 4.843 percent.

The Department projects that the amount of Bond Charge Revenues required for the 2009 Revenue Requirement Period will be $829 million.

ACCOUNTS AND FLOW OF FUNDS UNDER THE BOND INDENTURE

General information on the Accounts and flow of funds under the Bond Indenture, which has not changed since the bonds were issued in 2002, is contained in the Department's prior Determinations of Revenue Requirements, copies of which have been incorporated into the administrative record supporting this Determination.

Information specific to certain Accounts for this 2009 Revenue Requirement Determination follows.

OPERATING ACCOUNT

The Department has covenanted in the Bond Indenture to include in its revenue requirements amounts estimated to be sufficient to cause the amount on deposit in the Operating Account at all times during any calendar month to equal the Minimum Operating Expense Available Balance ("MOEAB"). The Bond Indenture leaves to the Department the determination as to how far into the future this minimum test of sufficiency should be met. Moreover, the covenant concerns the minimum amount required to be projected to be on deposit, and leaves to the Department the determination as to what total reserves are appropriate or required in the fulfillment of its duties under Section 80134 of the Act.

The Department determines the MOEAB at the time of each revenue requirement determination and is to be an amount equal to the largest projected difference between the Department's projected operating expenses and the Department's projected Power Charge revenues during any one month period during the revenue requirement period, taking into account a range of possible future outcomes (i.e., “stress cases”).

For the purposes of this 2009 Determination, the Department has determined the MOEAB to be $425 million. The Department projects to exceed the MOEAB at all times during 2009. The Department has determined that the amount projected to be on deposit in the Operating Account, including the amount therein that acts as a reserve for Operating Expenses, is just and reasonable, based in part on the following: (1) potential gas price volatility, (2) potential gas price escalation, (3) year-over-year revenue requirement volatility, and (4) credit rating agency and credit and liquidity facility considerations, as well as the factors discussed below under “Sensitivity Analysis” and in Section E—“Key Uncertainties in the Revenue Requirement Determination”.

OPERATING RESERVE ACCOUNT

The Operating Reserve Account Requirement (“ORAR”) is to be calculated, in respect of each Revenue Requirement Period, as the greater of (a) the largest aggregate amount projected by the Department by which Operating Expenses exceed Power Charge Revenues during any consecutive seven calendar months commencing in such Revenue Requirement Period and (b) 12 percent of the Department’s projected annual Operating Expenses, provided, however, that the projected amount will not be less than the applicable percentage of Operating Expenses for the most recent 12-month period for which reasonably full and complete Operating Expense information is available, adjusted in accordance with the Indenture to the extent the Department no longer is financially responsible for any particular Power Supply Contract. All projections are to be based on such assumptions as the Department deems to be appropriate after consultation with the Commission and taking into account a range of possible future outcomes (i.e., “Stress Cases”).

Additionally, the ORAR shall include, but shall not be limited to, the Priority Contract Contingency Reserve Amount (“PCCRA”). The PCCRA is the maximum amount projected by the Department to be payable by the Department under and pursuant to Priority Long Term Power Contracts in any calendar month during such Revenue Requirement Period. All projections are to be based on such assumptions as the Department deems to be appropriate after consultation with the Commission.

Based on the Stress Cases described below under “Sensitivity Analysis”, the ORAR for the 2009 Revenue Requirement Period is determined by the Department to be $667 million, reflecting an amount equal to the PCCRA. The Department projects to meet the ORAR on or before June 1, 2009.

DEBT SERVICE RESERVE ACCOUNT

For purposes of calculating the amount of the Debt Service Reserve Requirement from time to time, interest accruing on Variable Rate Bonds during any future period will be assumed to accrue at a rate equal to the greater of (a) 130 percent of the highest average interest rate on such Variable Rate Bonds in any calendar month during the twelve (12) calendar months ending with the month preceding the date of calculation, or such shorter period that such Variable Rate Bonds shall have been outstanding, or (b) 4.0 percent. For the 2009 Revenue Requirement Period, the Department will calculate projected interest on unhedged Variable Rate Bonds at 4.695 percent.

For the 2009 Revenue Requirement Period, the Department has determined the Debt Service Reserve Requirement to be $919 million. The Department projects to maintain this amount at all times during the Revenue Requirement Period.

SENSITIVITY ANALYSIS

The Rate Agreement requires the Department to evaluate its costs and cash flows on a monthly basis and to notify the Commission of its Retail Revenue Requirements no less than once each year, thereby ensuring that Bond Charges and Power Charges are adequate to meet financial obligations associated with the Bonds and the power supply program. From the date the Department first initiates any necessary revised Retail Revenue Requirement proceeding, it expects no more than seven months will elapse before it receives modified levels of revenues associated with the filing. As explained in prior Department revenue requirement determinations, during this seven month period the Department would endeavor to identify any material changes in its revenue requirement, proceed through its own administrative determination of its modified revenue requirement, notify the Commission of the new revenue requirement for purposes of allocating the costs among customers, and finally begin receiving the modified level of revenue. In order to ensure its ability to meet its financial obligations during this seven month period, the Department must maintain reserves that are adequate to meet normal anticipated expenses, unexpected variations in these expenses, and/or reductions in revenue receipts resulting from factors beyond the Department's control. The determination of reserve levels is made by the Department, considering such factors as the potential variations in revenue receipts and power supply program expenses, changes in key variables affecting customer energy requirements, IOU controlled or "retained" generation ("URG") production levels, changing natural gas prices, and Department contract operations, among other factors.

To assess the adequacy of reserve levels, the Department and its consultants have prepared an additional assessment of Stress Cases based on changes in certain key expense and operating assumptions. The Stress Cases considered in this assessment reflect a sampling of groups of changes in key assumptions that could affect Department expenses and revenues. The Stress Cases are not intended to reflect all possible scenarios, nor are they intended to reflect only those most likely to occur. For the Stress Cases, a market simulation was performed to generate revised net short requirements and associated power supply costs. These revised forecasts were used to generate revised cash flow projections for the Department. These revised results were compared against the base estimate of cash flow projections (the "Base Case").

CASE 1

This Stress Case focuses on decreased Bond Charge and Power Charge revenues resulting from lower sales to Department customers, and increased costs of providing energy under existing contracts.

Higher costs are driven primarily by increased fuel costs. This Stress Case utilizes a higher natural gas price forecast than is presented in Table D-9. This Stress Case gas price forecast, shown in Table D-10, was developed using basic statistical methods to define a high-end range of gas prices at the Henry Hub, Southern California Border and PG&E Citygate delivery points. These are the relevant primary delivery points for natural gas that would be procured to support DWR's long-term contracts.

TABLE D-10
STRESS CASE – NATURAL GAS PRICE FORECASTS
(Nominal $/MMBtu)

	Henry Hub	Southern California Border	PG&E Citygate
	2009	**2009**	**2009**
Q1 – 2009	21.56	21.28	23.86
Q2 – 2009	19.06	18.68	21.25
Q3 – 2009	19.18	18.97	21.60
Q4 – 2009	19.56	19.45	22.27
Annual Average	19.84	19.60	22.24

The Stress Case gas price forecast for each delivery point was developed using a set of historical monthly prices from the first of the month starting in April 1998 through May 2008 for Henry Hub gas prices with historical basis differentials used to estimate prices for each delivery point. The Department identified the distribution function that best fits the data through the use of specialized statistical software. Using the identified distribution functions, a Monte Carlo simulation was performed on each monthly Base Case gas price forecast to identify a gas price with a 99 percent probability of all gas prices within that specific distribution falling below it – presuming the Base Case gas price forecast is the mean point of the distribution. This gas price was then used as the Stress Case gas price forecast for that specific delivery point and month. While this methodology appears to provide the best method of statistically identifying a reasonable high-end range for gas prices, no statistical method will perfectly capture the variability in gas prices.

Gas hedges can be used to reduce the impact of changes in the spot market for gas. Based on information provided by the IOUs, the Department has included the impact of actual and planned gas hedges in place as of June 30, 2008. These hedges, in many instances, limit the price of natural gas purchases under the Stress Cases to levels below the Stress Case gas price forecast for those volumes and time periods for which the hedges are in place.

Lower customer sales by the Department are driven primarily by a decrease in the net short energy requirements, which can occur as a result of increased URG and/or decreased customer load. In this case, URG is increased by assuming California and Pacific Northwest hydroelectric production at 125 percent of normal for 2009 and 2010.

Lower loads are estimated in this case by assuming cooler-than-normal summers during 2009 and 2010, and by assuming increased non-programmatic conservation. The level of decreased customer load due to temperature variation is simulated by decreasing the Base Case total monthly load forecast for 2009 and 2010 by 3.3 percent, 3.6 percent, 5.1 percent and 4.4 percent for June, July, August, and September, respectively. In addition, an increase in the assumed level of non-programmatic conservation (above the Base Case) results in decreases in total annual load of four percent in 2009 and two percent in 2010. Lower electric loads result in a Stress Case for Department revenue because the fixed component of Department energy contracts must be allocated over fewer MWh of retail electric sales, thereby increasing the Department's required recovery cost per MWh.

CASE 2

This Stress Case focuses on increased costs of providing energy under existing contracts, and considers increased contract dispatch due to higher customer load and reduced URG.

Higher costs are driven primarily by increased fuel costs. As in Case 1, this Stress Case utilizes the higher natural gas price forecast that is presented in Table D-10.

Higher customer sales by the Department are driven primarily by an increase in the net short, which can occur as a result of decreased URG and/or increased customer load. In this case, URG is decreased by assuming California and Pacific Northwest hydroelectric production at 75 percent of normal in 2009 and 2010. URG is further decreased by assuming an unplanned outage at one southern California nuclear power plant unit from January 2009 through March 2009 and at one northern California nuclear power plant unit from April 2009 through March 2010. The expected impact of this type of an assumption is to increase the amount of energy dispatched from the Long-Term Priority Contracts.

Higher loads are estimated in this case by assuming load growth rates that are 2.0 percentage points higher than those assumed in the Base Case in 2008 and 1.4 percent higher in 2009. It is assumed that this growth occurs as a result of the combination of accelerated economic growth in California and decreases in the expected amount of achieved non-programmatic conservation. In addition, load is increased by assuming the existence of warmer-than-normal summers in 2009 and 2010. The level of increased customer load due to temperature variation is simulated by increasing the Base Case total monthly load forecast (inclusive of the accelerated growth rates described above) in 2009 and 2010 by 4.4 percent, 4.8 percent, 6.8 percent, and 5.9 percent for June, July, August, and September, respectively.

E. POWER CONTRACT SETTLEMENT SUMMARY

The California Parties, which include the Governor's Office, California Attorney General's Office, CPUC, California Electricity Oversight Board, the Department and IOUs have been participating in FERC proceedings to recover excess electricity costs incurred by ratepayers since 2001. These FERC proceedings have led to several settlement agreements between the California Parties and the responsible energy suppliers. As one of the California Parties, the Department has received distributions from these energy suppliers that have been paid to settle claims against them. Any future settlement distributions will reduce Department costs and, as a result, decrease the Department's revenue requirement. Copies of prior settlement agreements are incorporated into the administrative record supporting this Determination.

F. KEY UNCERTAINTIES IN THE REVENUE REQUIREMENT DETERMINATION

There are a number of uncertainties facing the Department that may require material changes to its revenue requirements for the 2009 Revenue Requirement Period after this 2009 Determination. Several risk factors are outlined below and additional information may be found in each of the bond financing Official Statements, which may be obtained from the Treasurer of the State of California

1. Determination of Power Charges and Bond Charges; possible use of amounts in the Bond Charge Collection Account to pay Priority Contract Costs:
    a. Potential administrative and legal challenges to DWR's revenue requirements;
    b. Potential litigation regarding inclusion of DWR Priority Contract Costs in its Retail Revenue Requirement; and
    c. Application and enforcement of the Rate Agreement's Bond Charge rate covenant.

2. Collection of Bond Charges and Power Charges:
    a. Potential rejection of Servicing Arrangements or other disruption of servicing arrangements.

3. Certain risks associated with DWR's Power Supply Program:
    a. Long-term power contracts:
        i. Impact of renegotiated contracts;
        ii. Off-system sales volume and price variability;
        iii. Failure or inability of the suppliers to perform as promised including but not limited to any failure to add new capacity to the grid or a possible rejection of a contract in bankruptcy;
    b. Gas price volatility; and
    c. "Block Forward Contracts" consolidated actions.

4. Potential increases in overall electric rates:
    a. Changes in general economic conditions;
    b. Energy market-driven increases in wholesale power costs;
    c. Fuel costs;
    d. Hydro conditions and availability;
    e. Market manipulation; and
    f. Actions affecting retail rates.

5. Potential decrease in DWR customer base:
    a. Direct Access; and
    b. Load departing IOU service.

6. Potential variance in dispatch of DWR contracts:
    a. Actual vs. forecast load variance;
    b. Dispatch coordination between IOUs and DWR; and
    c. Modification of sharing of surplus power sales revenues.

7. Uncertainties relating to electric industry and markets:
    a. Electric transmission constraints;
    b. Gas transmission constraints; and
    c. CAISO implementation of its Market Redesign and Technology Upgrade.

8. Uncertainties relating to government action:
    a. California Emergency Services Act;
    b. Possible State legislation or action; and
    c. Possible Federal legislation or action.

G. JUST AND REASONABLE DETERMINATION

PRIOR DETERMINATIONS

Each new revenue requirement determination builds, to the extent necessary or appropriate, on the various preceding determinations. Successive determinations incorporate the information from each previous determination into the supporting administrative record. Determinations are available for review on the DWR-CERS website by interested persons, and the supporting materials are available at the CERS office in Sacramento, subject to applicable non-disclosure requirements.

Determination	Date Issued
2001-2003, including Reexamination and Redetermination for 2001-2002	August 16, 2002
Reconsideration of Just and Reasonableness of 2001 - 2003	August 19, 2004
2003 Supplemental	July 1, 2003
2004	September 18, 2003
2004 Supplemental	April 16, 2004
2005	November 4, 2004
Revised 2005	March 16, 2005
2006	August 3, 2005
Final 2006	October 27, 2005
2007	August 2, 2006
Revised 2007	October 30, 2006
2008	August 22, 2007
Revised 2008	October 31, 2007
Supplemental 2008	February 15, 2008

THE 2009 DETERMINATION

PUBLIC PROCESS

Under the terms of the Rate Agreement between the Department and the Commission, and the terms of the Bond Indenture, the Department has agreed to review, determine and revise its Retail Revenue Requirement at least annually.

On July 8, 2008, the Department issued its Proposed Determination of Revenue Requirements for the period January 1, 2009, through December 31, 2009 for public review and comment under the Regulations promulgated pursuant to the California Administrative Procedures Act. The Department provided interested persons with quantitative results from its PROMOD market simulation and Financial Model, subject to applicable non-disclosure requirements. Interested persons were advised to submit comments no later than July 29, 2008.

On July 29, 2008, the Department received comments from Pacific Gas and Electric Company and Southern California Edison Company. No other persons submitted comments. The Department reviewed and considered each comment and took action as appropriate. The comments are summarized in Section I, and the complete comments are included in the administrative record and are referenced in Section J.

JUST AND REASONABLE DETERMINATION

After assessing the administrative record, the Act, the Regulations, Bond Indenture requirements and the Rate Agreement, the Department finds this 2009 Revenue Requirement Determination for the period of January 1, 2009 through December 31, 2009, to be just and reasonable.

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H. MARKET SIMULATION

Wholesale power costs in the western United States are driven by a multitude of factors. These include weather and related electricity demand, precipitation and related hydropower production, supply and price of natural gas and coal, power transfer capability of major interties, operating costs, outages and retirement of generating plants, and the cost, fuel efficiency, and timing of new generating resource additions. The Department analyzed the fundamental drivers underlying the electricity market by generating computer simulations of market activity throughout the Western Electricity Coordinating Council ("WECC") region.

As part of its market report and simulation in developing the 2009 Revenue Requirement, the Department considered all items in the above paragraph and the following:

- California ISO Market Redesign and Technology Upgrade;
- Potential impacts of market redesign on the Department's long-term contracts and revenue requirements;
- Use of PROMOD IV as a market simulation tool;
- Analysis of retirement and additions of WECC generation resources; and
- California ISO Locational Marginal Price and Congestion Revenue Rights proposals.

More detailed information about the market simulation utilized by the Department, including descriptions of the inputs and assumptions is referenced in Section J of the 2008 Revenue Requirement.

I. COMMENTS RECEIVED ON THE PROPOSED 2009 DETERMINATION AND THE DEPARTMENT'S RESPONSES

On July 8, 2008, the Department issued its Proposed 2009 Revenue Requirement Determination for the period January 1, 2009 through December 31, 2009. This document was made available for public review and comment. The Department provided interested persons with quantitative results from its PROMOD market simulation and Financial Model, subject to applicable non-disclosure requirements. Interested persons were advised to submit comments no later than July 29, 2009.

The Department received comments from PG&E and SCE. No other persons submitted comments. The Department reviewed and considered each comment and took action as appropriate. The comments and the Department's responses are reviewed below. The completed responses are included in the administrative record and are referenced in Section J.

Summary of Comments of Pacific Gas and Electric

PG&E Comment #1:
In its July 29, 2008 comments, PG&E states that DWR's initial workpapers supporting the Proposed Determination did not include avoidable costs for the Iberdrola Renewables (formerly

PPM Energy) contract beyond 2008 even though energy deliveries continue through 2011. PG&E requested that DWR's forecasted costs be updated to show the avoidable cost of dispatch of the Iberdrola Renewables contract from 2009 through 2011.

Response: The Department, in and through discussions with PG&E and in recognition of historical dispatch levels, has made efforts to accurately reflect the expected dispatch of the Iberdrola Renewables contract in its contract dispatch and cost projections. During these efforts, as noted by PG&E, a data reporting error resulted in an understatement of the variable cost of the Iberdrola Renewables contract. The Department has corrected this reporting error. As a result, contract costs are projected to increase by approximately $110 million for the 2009 Revenue Requirement period when compared to the Proposed 2009 Determination. The correction was made for the years 2009 through 2011.

PG&E Comment #2:
PG&E requested that DWR reflect PG&E's most recent estimate of transmission and distribution losses and unaccounted for energy which was provided to the Department in PG&E's response to the 2009 Revenue Requirement Data Requests.

Response: This change has been made and is reflected in this 2009 Determination of Revenue Requirements.

PG&E Comment #3:
PG&E comments that "…DWR's forecast dispatch of PG&E's DWR contracts is significantly lower than PG&E's most recent forecast. PG&E forecasts approximately 8.5% more MWh of energy from its dispatchable contracts in 2009 than does DWR. This disparity is particularly strong in the warmer months, June through September. PG&E hopes that DWR will continue to work with PG&E to bring the two forecasts closer together, or at least, closer to historical levels of dispatch."

Response: The purpose of the Department's market simulation is to provide a reasonable projection of the Department's costs and dispatch of its contracts. The Department is continually trying to identify ways to refine its forecasts. While the Department has a responsibility to maintain the integrity of an independent analysis and review, it greatly appreciates PG&E's and the other utilities' assistance in formulating modeling assumptions and reviewing results. PG&E noted that DWR's forecasted annual dispatch is lower than that forecast by PG&E. The Department recognizes this disparity and both Department and PG&E staff will continue to work together to try to determine the source of the variance.

The dispatched energy forecast for PG&E's DWR contracts developed by the Department is consistent with the methodology used for all other resources in the entire Western Electricity Coordinating Council region. The Department utilizes a production simulation model that considers a number of factors which interact to determine the market clearing price of electricity, which, along with resource marginal cost of production, load levels, availability of other resources and transmission capability, are primary drivers of individual resource dispatch levels.

Any difference in the projected dispatch levels developed by PG&E and the Department is likely related to assumed market clearing prices of electricity and the relationship of those prices to individual plant production and delivery costs. The Department's market simulation projections of average monthly market clearing price in northern California in 2009 appear lower than PG&E's projections. In a production simulation analysis, all other things being equal, this will lead to a lower level of dispatch from the dispatchable contracts than PG&E (with higher market clearing prices) would project.

At this time, the Department has determined that its current forecast and its underlying assumptions are just and reasonable and does not plan to revise the forecasted contract dispatch.

Summary of Comments of Southern California Edison

SCE Comment #1:

In its July 29, 2008 comments, SCE notes that the Proposed Determination utilizes a June 2008 forecast of average natural gas prices for 2009 and 2010. In this forecast, the projected average natural gas price at the Southern California Border delivery point in 2009 is projected to be $11.61/MMBtu, which, SCE notes, is significantly higher than the $9.87/MMBtu reflected in a recent (July 21, 2008) "publicly-available" forecast. SCE's comments that DWR should confirm its intention to update its natural gas price forecast for the 2009 Determination by October 2008 and requests that DWR allow SCE to provide input for and analysis of this forecast before it is finalized and incorporated in the 2009 Determination.

Response: The Department recognizes that natural gas price projections underlying the Proposed Determination differ from recent price projections. Natural gas prices have been extremely volatile for both the 2009 Revenue Requirement Period and for the remaining months of 2008. Based on these observed differences, the Department has updated its natural gas price forecast for the remaining months of 2008.

The update to the 2008 gas price forecast results in gas prices that are approximately $3/MMBtu lower than the forecast previously used to project the Department's cost for the remainder of 2008. The lower gas prices affect this 2009 Determination by increasing the projected January 1, 2009 power charge account balances. The change in projected January 1, 2009 balances can be observed on Table B-1 in this Revenue Requirement. The 2009 Revenue Requirement projection of contract costs is not affected.

Additionally, as is its practice, the Department will be updating its natural gas price forecast for 2009 and 2010 by October 2008 and intends to solicit input from the IOUs and all interested persons during this process.

SCE Comment #2:

SCE comments that the workpapers supplied with the Proposed Determination pertaining to "Supply from Utility Resources" contain some minor errors and requests that the Department's resource modeling personnel work with SCE to review and correct the discrepancies. SCE also requests that DWR update its estimate of “Supply from Utility Resources” in Table D-3 of this Determination.

Response: The Department will continue its collaboration with SCE to accurately reflect the dispatch of SCE resources in its PROMOD projections.

The main purpose of the Department’s market simulation is to provide a reasonable projection of the Department’s costs and dispatch of its contracts. Since correcting minor discrepancies in the SCE resource portfolio will not meaningfully affect the cost and dispatch of the Department’s contracts, the Department has determined that its current forecast and its underlying assumptions are just and reasonable and does not plan to revise the forecasted contract dispatch.

After its fall update of gas prices, the Department will run a new market simulation and if the collaborative efforts of the Department and SCE dictate a change to some of the underlying assumptions affecting the “Supply from Utility Resources”, such changes will be made at that time.

J. ANNOTATED REFERENCE INDEX OF MATERIALS UPON WHICH THE DEPARTMENT RELIED TO MAKE THE DETERMINATION

Volume	Record Number	Date	Record Title
DWR09pRR	001	02/15/08	Supplemental Determination of Revenue Requirements for 2008, including the Notice and the Determination
DWR09pRR	002	02/22/08	ALJ Ruling inviting comments on the Allocation of the CDWR’s determination of its supplemental revenue requirements for 2008
DWR09pRR	003	04/10/08	Decision 08.04.025: Order Granting In Part, The Petition To Modify Decision 05.06.060
DWR09pRR	004	04/14/08	DWR Data Request 1 including Transmittal, Load Forecast Questions, Load Forecast matrix, CEC Energy Facility Status, Hedging matrix
DWR09pRR	005	04/24/08	Decision 08.04.051: Order Allocating The 2008 Supplemental Revenue Requirement Determination Of The CDWR
DWR09pRR	006	04/30/08	SDG&E Advice 1986-E: Revision To The DWR Power Charge Remittance Rate Pursuant To D.08.04.051
DWR09pRR	007	04/30/08	PG&E Advice 3263-E: Tariff Revision in response to D.08.04.051
DWR09pRR	008	05/08/08	SCE Advice 2239-E: Revision of the 2008 CDWR Power Charge Pursuant to D.08.04.051
DWR09pRR	009	04/28/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Response to DWR Data Request, questions 2-6
DWR09pRR	010	04/29/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE Response to DWR’s Data Requests

DWR09pRR	011	05/02/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E Response to DWR Data Request: Load Data
DWR09pRR	012	04/29/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Response to DWR Data Request, questions 1 and 7
DWR09pRR	013	05/02/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Response to DWR Data Request, questions 3 and 5
DWR09pRR	014	05/05/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE Response to Questions on Load Data
DWR09pRR	015	05/05/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Response to DWR Data Request, question 8
DWR09pRR	016	05/06/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E Response to DWR Data Request: Q8
DWR09pRR	017	05/08/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E Response to DWR Data Request: Q1, Q8 Update
DWR09pRR	018	05/07/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Follow up Questions on Data Response from PG&E
DWR09pRR	019	05/12/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Follow up Questions on Data Response from SCE
DWR09pRR	020	05/13/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Follow up Questions on Data Response from SCE
DWR09pRR	021	05/13/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE Response to DWR Follow up Questions
DWR09pRR	022	05/13/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Supplemental Response to DWR Data Request
DWR09pRR	023	05/13/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE Response to DWR Follow up Questions
DWR09pRR	024	05/13/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE Response to DWR Follow up Questions
DWR09pRR	025	05/14/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E Response to DWR Data Request
DWR09pRR	026	05/14/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E Response to DWR Data Request: Hedging
DWR09pRR	027	05/14/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Supplemental Response to DWR Data Request: Hydro
DWR09pRR	028	05/14/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E Response to DWR Data Request: Losses
DWR09pRR	029	05/19/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PROMOD data to SDG&E for Review and Comment
DWR09pRR	030	05/19/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PROMOD data to SCE for Review and Comment
DWR09pRR	031	05/19/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PROMOD data to PG&E for Review and Comment
DWR09pRR	032	05/19/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E comments on PROMOD usage forecast
DWR09pRR	033	05/19/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E additional comments on PROMOD data
DWR09pRR	034	05/19/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Supplemental Data Request Response
DWR09pRR	035	05/19/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR Response to PG&E Questions on PROMOD Data

DWR09pRR	036	05/19/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Additional Response on PROMOD for Pacificorp
DWR09pRR	037	05/20/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Additional Response on PROMOD
DWR09pRR	038	05/20/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE Additional Comments on PROMOD Data
DWR09pRR	039	05/21/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Additional Response on PROMOD
DWR09pRR	040	05/21/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE Additional Comments on PROMOD Data - Hydro
DWR09pRR	041	05/22/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Additional Response on PROMOD
DWR09pRR	042	05/22/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E Additional Response on PROMOD
DWR09pRR	043	05/22/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Further Clarification of QF Data
DWR09pRR	044	05/22/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Further Clarification of QF Data: Pacificorp
DWR09pRR	045	05/23/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Further Clarification of QF Data
DWR09pRR	046	05/23/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Additional Response on PROMOD: Coral Contract
DWR09pRR	047	05/23/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Additional Response on PROMOD: Avoidable – Non-Avoidable Costs
DWR09pRR	048	05/23/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE Additional Comments on PROMOD Data
DWR09pRR	049	05/30/08	DWR Data Request for Additional Dispatchable Unit Information to SCE
DWR09pRR	050	05/30/08	DWR Data Request for Additional Dispatchable Unit Information to SDG&E
DWR09pRR	051	05/30/08	DWR Data Request for Additional Dispatchable Unit Information to PG&E
DWR09pRR	052	05/30/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E Response to Dispatchable Data Request
DWR09pRR	053	05/30/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Response to Dispatchable Data Request
DWR09pRR	054	06/03/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: Additional questions on PG&E Dispatchable
DWR09pRR	055	06/04/08	DWR Response to PG&E Questions
DWR09pRR	056	05/28/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E Comparison of URG and Base Case Data
DWR09pRR	057	06/04/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Response to Coral Contract Questions
DWR09pRR	058	06/04/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Response to Capacity Questions
DWR09pRR	059	06/04/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE Response to Dispatchable Unit Questions
DWR09pRR	060	06/10/08	DWR request to SCE for additional information relating to PROMOD data

DWR09pRR	061	06/10/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR additional questions to PG&E related to PROMOD data
DWR09pRR	062	06/10/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Response to Additional Questions – Crockett Cogen
DWR09pRR	063	06/10/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E Response to Additional Questions – Wind Generators
DWR09pRR	064	06/10/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E additional response to – Crockett Cogen
DWR09pRR	065	06/10/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E additional response to – Wind Units
DWR09pRR	066	06/10/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E additional response to – Helms and Puget Exchange
DWR09pRR	067	06/12/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE response to additional questions
DWR09pRR	068	06/12/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SDG&E data clarifications
DWR09pRR	069	06/12/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR request to PG&E for data clarifications – contract extensions
DWR09pRR	070	06/12/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E response to contract extensions request
DWR09pRR	071	06/13/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: DWR request to SCE for data clarifications – contract extensions
DWR09pRR	072	06/13/08	Guidance for modeling SCE contract extensions
DWR09pRR	073	06/13/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PPM Contract Data
DWR09pRR	074	06/13/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PPM additional Contract Data
DWR09pRR	075	06/13/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: SCE input on contract extensions
DWR09pRR	076	06/16/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: PG&E additional response to contract extensions request
DWR09pRR	077	03/03/08	DWR Electric Power Fund Financial Statements: December 31, 2007
DWR09pRR	078	05/22/08	DWR Electric Power Fund Financial Statements: March 31, 2008
DWR09pRR	079	05/22/08	Bond Refunding Official Statements: Series H, I, J, K
DWR09PRR	080	07/03/08	DWR General and Administrative Long Term Cost Forecast
DWR09RR	081	07/08/08	Proposed Determination of Revenue Requirements for 2009 including the Notice, the Regulations and the Proposed Determination
DWR09RR	082	07/08/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: Data files supporting the 2009 Proposed Determination of Revenue Requirements, specific to PG&E
DWR09RR	083	07/08/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: Data files supporting the 2009 Proposed Determination of Revenue Requirements, specific to SCE

DWR09RR	084	07/08/08	CONFIDENTIAL: NOT FOR PUBLIC RELEASE: Data files supporting the 2009 Proposed Determination of Revenue Requirements, specific to SDG&E
DWR09RR	085	07/29/08	PG&E Comments on the Proposed Determination for 2009
DWR09RR	086	07/29/08	SCE Comments on the Proposed Determination for 2009
DWR09RR	087	07/29/08	Long Term Natural Gas Price Forecasts with 10-day NYMEX average prices as of June 24, 2008.
DWR09RR	088	08/01/08	Natural Gas Price Forecasts for 2008 using 10-day NYMEX average prices as of July 31, 2008.