State of California

Department of Water Resources

Proposed

Determination of Revenue Requirements

For the Period

January 1, 2007, Through December 31, 2007

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

June 22, 2006

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A. THE PROPOSED DETERMINATION

GENERAL

Pursuant to Section 80110 of the California Water Code, the Rate Agreement between the State of California Department of Water Resources (the "Department" or "DWR") and the California Public Utilities Commission (the "Commission" or "CPUC"), dated March 8, 2002 (the "Rate Agreement"), and Division 23, Chapter 4, Sections 510–517 of the California Code of Regulations ("the Regulations"), the Department hereby issues its Proposed Determination of Revenue Requirements for the period January 1, 2007, through December 31, 2007 (the "2007 Proposed 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").

In January and February of 2001, the Department assumed responsibility for the purchase of the net short energy requirements of the retail customers of the three California investor-owned utilities (the "Utilities" or "IOUs") namely, Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE") and San Diego Gas & Electric Company ("SDG&E"). On February 1, 2001, Assembly Bill 1 from the First Extraordinary Session of 2001 was signed into law, enacting California Water Code Division 27 (as subsequently amended, "the Act"). The Act authorized the Department to purchase the net short energy requirements of the IOUs. The term "net short" is used herein to mean total IOU customer energy requirements minus supply from resources owned, operated or contracted by the IOUs. The Department, in accordance with the Act, procured all of the net short requirements of the IOUs through the end of 2002 using a combination of long-term power contracts, short-term power contracts and wholesale energy purchases. After allowing for the energy provided under the Department's long-term power contracts, the amount of energy required to be purchased (initially on a short-term basis) to meet IOU customer needs is herein called the "residual net short." For purposes of the 2007 Proposed Determination, the residual net short for each IOU equals the projected amount of wholesale energy remaining at any given time to be procured by such IOU on behalf of ratepayers in its service area.

If the Department had not entered into long-term contracts, a greater volume of net short energy would have been purchased in the spot market between January 2001 and December 2002, the period during which the Department had the responsibility for procuring the entire net short energy requirement. Similarly, after 2002, any net short energy requirements not provided under the Department's long-term contracts are to be purchased by the three IOUs, either as spot market purchases or under new contracts authorized by the Commission in accordance with Assembly Bill 57 ("AB 57"), which was enacted on September 24, 2002.

AB 57 provided for each of the IOUs to resume procurement of their customers' energy requirements, which are not served by the Department, beginning January 1, 2003. The legislation further required each utility to provide to the Commission an energy procurement plan, including a description of the required energy products for the utilities to meet their residual net short energy needs.

At the time the Department entered into long-term contracts, Assembly Bill 57 had not been enacted and it was uncertain when all three of the utilities would be sufficiently creditworthy to purchase their own residual net short energy requirements. The Commission commenced implementation of the energy procurement process contemplated by AB 57 for the first time in the fourth quarter of 2002.

On January 1, 2003, the IOUs resumed the responsibility of procuring the residual net short. Since that time, the Department's role in procuring power to meet the net short has been limited to the provision of power from contracts entered into by the Department prior to January 1, 2003.

The costs of the Department's purchases to meet the net short requirements of retail end use customers in the IOUs' 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]

The Department funded its purchases of energy from January 17, 2001, through December 31, 2002, from three sources: payments collected from retail customers by the IOUs on behalf of the Department, advances from the State General Fund, and the proceeds of an interim financing of $4.3 billion issued in June 2001 (the "Interim Loan"). In October and November of 2002, the State issued $11.263 billion of revenue bonds. The proceeds were applied to reimburse the General Fund, pay off of the Interim Loan, and create certain debt service reserves and operating reserves. Repayment of the bonds will be made from Bond Charges established under the Rate Agreement and applicable Decisions of the Commission and from amounts in the related accounts, as described in more detail herein.

Pursuant to Sections 80110 and 80134 of the California Water Code and the Rate Agreement, this Proposed Determination contains information on the amounts required to be recovered, on a cash basis, in the 2007 Revenue Requirement Period (calendar year 2007).

This 2007 Proposed Determination takes into account preliminary actual operating results of the Department through April 30, 2006 and projected operating results through the end of 2006.

[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.

For the 2007 Revenue Requirement Period, this Proposed Determination contains information regarding the following[2]: (a) the projected beginning balance of funds on deposit in the Electric Power Fund (the "Fund"), including the amounts projected to be on deposit in each account and sub-account of the Fund; (b) the amounts projected to be necessary to pay the principal, premium, if any, and interest on all bonds as well as 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 meet the Department's Costs, including all Retail Revenue Requirements.

PROPOSED DETERMINATION OF REVENUE REQUIREMENTS

Pursuant to the Act, the Rate Agreement and the Regulations, the Department proposes to determine, on the basis of the materials presented and referred to by this 2007 Proposed Determination (including the materials referenced in Section I), that its cash basis revenue requirement for 2007 is $5.241 billion, consisting of $4.432 billion in Department Costs and $0.809 billion in Bond Related Costs.

As previously noted, this 2007 Proposed Determination takes into account preliminary actual operating results through April 30, 2006 and projected operating results through the remainder of the 2006 Revenue Requirement Period. Actual costs expended and revenues received by the Department during the 2006 Revenue Requirement Period will directly affect the Department's beginning account balances for the 2007 Revenue Requirement Period. To the extent that actual expenses and revenues differ from those projected in the Department's Final 2006 Determination of Revenue Requirements for the period January 1, 2006 through December 31, 2006, published October 27, 2005 (the "Final 2006 Determination"), the Department's beginning account balances for the 2007 Revenue Requirement Period will also differ from those projected in the Final 2006 Determination.

Any net surpluses collected during the 2006 Revenue Requirement Period, which may result from the receipt of funds related to various litigation settlements involving the Department, lower natural gas prices and other considerations, are projected to offset costs incurred by the Department in 2007. Potential sources of operating surpluses are addressed within Section D and Section E of this Proposed Determination. The Department intends to update its projections for this 2007 Proposed Determination, based on actual operating results through mid-summer 2006, later this year.

Table A-1 shows a summary of the Department's revenue requirements and the accounts associated with projected Department Costs ("Power Charge Accounts") for 2007. These figures are compared to those reflected in the Department's Final 2006 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.

[2] Where appropriate, the Department has provided information in this Proposed 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 2007 Proposed Determination, quantitative statistics presented in tabular form may not add due to rounding.

TABLE A-1
SUMMARY OF THE DEPARTMENT'S PROPOSED 2007 POWER CHARGE REVENUE REQUIREMENTS AND POWER CHARGE ACCOUNTS AND COMPARISON TO 2006[1]
($ Millions)

Line	Description	2007[2]	2006[3]	Difference
1	*Beginning Balance in Power Charge Accounts*			
2	Operating Account	1,139	929	210
3	Priority Contract Account	-	-	-
4	Operating Reserve Account	591	555	36
5	**Total Beginning Balance in Power Charge Accounts**	**1,730**	**1,483**	**246**
6	*Power Charge Accounts Operating Revenues*			
7	Power Charge Revenues[4]	4,432	4,546	(114)
8	Extraordinary Receipts[5]	-	-	-
9	Other Revenue[6]	232	235	(3)
10	Interest Earnings on Fund Balances	74	44	30
11	**Total Power Charge Accounts Operating Revenues**	**4,738**	**4,825**	**(87)**
12	*Power Charge Accounts Operating Expenses*			
13	Administrative and General Expenses	26	36	(10)
14	Total Power Costs	4,956	4,987	(31)
15	Gas Hedging Costs	90	-	90
16	Extraordinary Contract Expenses	(98)	(99)	1
17	**Total Power Charge Accounts Operating Expenses**	**4,974**	**4,924**	**50**
18	Total Net Revenues	(236)	(100)	(137)
19	**Ending Aggregate Balance in Power Charge Accounts**	**1,493**	**1,384**	**110**

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.	376	371	5
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 and (ii) 12% of the Department's projected annual operating expenses for the current or immediately preceding Revenue Requirement Period.	595	591	4
Total Operating Reserves:	971	962	9

[1]Numbers may not add due to rounding.
[2]As proposed herein.
[3]As reflected in the Final 2006 Determination.
[4]Includes Bundled customer revenues and CRS revenues, whether from Direct Access or other sources, such as Community Choice Aggregation.
[5]Includes funds distributed to the Department as specified in settlement agreements with various energy suppliers; details related to individual settlement receipts are further discussed in Section D.
[6]Includes revenues received by the Department from 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.

TABLE A-2
SUMMARY OF THE DEPARTMENT'S PROPOSED 2007 BOND CHARGE REVENUE REQUIREMENTS AND BOND CHARGE ACCOUNTS AND COMPARISON TO 2006[1]
($ Millions)

Line	Description	2007[2]	2006[3]	Difference
1	*Beginning Balance in Bond Charge Accounts*			
2	Bond Charge Collection Account	156	207	(51)
3	Bond Charge Payment Account	587	573	13
4	Debt Service Reserve Account	913	927	(14)
5	**Total Beginning Balance in Bond Charge Accounts**	**1,655**	**1,707**	**(52)**
6	*Bond Charge Accounts Revenues*			
7	Bond Charge Revenues from Utilities[4]	809	820	(11)
8	Interest Earnings on Fund Balances	73	62	11
9	**Total Bond Charge Accounts Revenues**	**882**	**882**	**(1)**
10	*Bond Charge Accounts Expenses*			
11	Debt Service on Bonds[5]	901	898	3
12	**Total Bond Charge Accounts Expenses**	**901**	**898**	**3**
13	Total Net Revenues	(20)	(16)	(4)
14	**Ending Aggregate Balance in Bond Charge Accounts**	**1,635**	**1,691**	**(56)**

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.	75 - 76	75 - 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.	311 - 810	228 - 835	
Debt Service Reserve Account: Established as the maximum annual debt service.	913	913	

[1]Numbers may not add due to rounding.
[2]As proposed herein.
[3]As reflected in the Final 2006 Determination.
[4]CRS Bond Charge 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 revise its revenue requirements for the 2007 Revenue Requirement Period given the potential for significant or material changes in the California energy market, the status of market participants and 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

Section 80110 of the Water Code provides in part that "The Department shall be entitled to recover, as a revenue requirement, amounts and at the times necessary to enable it to comply with Section 80134, and shall advise the Commission as the Department determines to be appropriate." Section 80110 also provides that "any just and reasonable" review shall be conducted and determined by the Department. In addition, Section 80134 of the Water Code provides that:

> "(a) The Department shall, and in any obligation entered into pursuant to this division may covenant to, at least annually, and more frequently as required, establish and revise revenue requirements sufficient, together with any moneys on deposit in the fund, to provide all of the following:
>
> > "(1) The amounts necessary to pay the principal of and premium, if any, and interest on all bonds as and when the same shall become due.
> >
> > "(2) The amounts necessary to pay for power purchased by it and to deliver it to purchasers, including the cost of electric power and transmission, scheduling, and other related expenses incurred by the department, or to make payments under any other contracts, agreements, or obligation entered into by it pursuant hereto, in the amounts and at the times the same shall become due.
> >
> > "(3) Reserves in such amount as may be determined by the Department from time to time to be necessary or desirable.
> >
> > "(4) The pooled money investment rate on funds advanced for electric power purchases prior to the receipt of payment for those purchases by the purchasing entity.
> >
> > "(5) Repayment to the General Fund of appropriations made to the fund pursuant hereto or hereafter for purposes of this division, appropriations made to the Department of Water Resources Electric Power Fund, and General Fund moneys expended by the department pursuant to the Governor's Emergency Proclamation dated January 17, 2001.
> >
> > "(6) The administrative costs of the Department incurred in administering this division.
>
> "(b) The Department shall notify the Commission of its revenue requirement pursuant to Section 80110."

THE RATE AGREEMENT

In February 2002, the Commission issued a decision adopting the Rate Agreement between the Commission and the Department establishing the procedures to be followed to calculate and adjust the charges to customers for Department power, such that the Department is assured of recovering its Retail Revenue Requirements.[3] Among other purposes, the adoption of the Rate Agreement served to facilitate the issuance of bonds that enabled the repayment of the General Fund and Interim Loan and the funding of appropriate reserves for the bonds. On November 14, 2002, the final bond issue was completed. The General Fund and Interim Loan were repaid.

The Rate Agreement provides for two significant streams of revenue for the Department. One revenue stream is generated from "Bond Charges" imposed for the purpose of providing sufficient funds to pay "Bond Related Costs." Bond Charges are applied based on the aggregate amount of electric power sold to each customer by the Department and the applicable IOU, and, to the extent provided by final unappealable Commission orders, Electric Service Providers. Bond Related Costs include Bond debt service, Qualified Swap payments, credit enhancement and liquidity facilities charges, and costs relating to other financial instruments and servicing arrangements relative to the Bonds. The Rate Agreement requires the Commission to impose Bond Charges sufficient to ensure that amounts on deposit in the Bond Charge Payment Account are adequate to pay all Bond Related Costs as they come due. Bond Charges are imposed upon customers within IOU service territories regardless of whether those customers purchase their energy supplies from the Department and/or IOUs or Electric Service Providers.

The second revenue stream is generated from "Power Charges" imposed on customers who buy power from the Department, and is designed to pay for "Department Costs," including the costs that the Department incurs to procure and deliver power. The Rate Agreement requires the Commission to impose Power Charges that are sufficient to provide moneys in the amounts and at the times necessary to satisfy the Retail Revenue Requirements as specified by the Department.

An additional revenue stream for the payment of Department Costs is provided by components of cost responsibility surcharges imposed by the Commission on customers other than those who buy power from the Department--for example, Direct Access or Community Choice Aggregation customers. To the extent these cost responsibility surcharges are imposed and remitted to DWR, the Department's Retail Revenue Requirement (Power Charges to be collected from bundled customers) is lower. This 2007 Proposed Determination does not separately specify the sources of revenues to pay Department Costs and accounts for all revenues as if they were Power Charges and included in the Retail Revenue Requirement.

Revenues received from Power Charges and Bond Charges, as well as the payment of expenditures and obligations from such revenues, are held in, and accounted for under, the Electric Power Fund established by the Department under the Act.

Revenues from Power Charges and related cost responsibility surcharges are deposited into an "Operating Account." Funds in the Operating Account are used to pay certain Department Costs

[3] California Public Utilities Commission, Decision 02-02-051, "Opinion adopting a Rate Agreement between the Commission and the California Department of Water Resources," adopted February 21, 2002, as modified by Decision 02-03-063, adopted March 21, 2002.

and are also transferred at least monthly on a priority basis to a “Priority Contract Account.” The Priority Contract Account is used to pay for the costs that the Department incurs under its Priority Long Term Power Contracts (“PLTPCs”), which have terms that require the Department to pay for power purchased under these contracts ahead of Bond Related Costs (such as Bond debt service).

In addition, the Department funds an “Operating Reserve Account” to be drawn upon in the event that there are shortfalls in the Operating Account or the Priority Contract Account.

Revenues from Bond Charges are deposited into a “Bond Charge Collection Account.” Funds in the Bond Charge Collection Account are transferred periodically to a “Bond Charge Payment Account.” Funds in the Bond Charge Payment Account may only be used to pay Bond Related Costs. Funds in the Bond Charge Collection Account may be used to pay amounts due under the PLTPCs to fulfill the priority payment requirements of the PLTPCs if and only if amounts in the Priority Contract Account, the Operating Account and the Operating Reserve Account are insufficient. If the Bond Charge Collection Account is used to pay amounts due under PLTPCs, the Bond Charge Collection Account is to be replenished or reimbursed from amounts, when available, in the Operating Account.

These Bond Charge and Power Charge accounts are further described in Section D.

PRIOR PROCEEDINGS RELATING TO 2006 AND THE PROJECTED STARTING BALANCE FOR 2007

On June 8, 2005, the Department published its Proposed Determination of Revenue Requirements for 2006, consistent with the requirements of Sections 80110 and 80134 of the California Water Code and the Regulations, and provided information consistent with the requirements of the Rate Agreement. The cash basis revenue requirement projected therein totaled $5.282 billion, which consisted of $4.408 in Department Costs and $0.874 in billion in Bond Related Costs.

On July 13, 2005, the Department issued a Notice of Additional Material, and provided such additional material upon which it intended to rely in making its 2006 Determination. During the period between June 8, 2005, and July 20, 2005, the Department responded to questions in an effort to assist interested persons in the review and understanding of the Proposed 2006 Determination and additional materials. On July 20, 2005, the Department received comments on the Proposed 2006 Determination from PG&E, SCE and SDG&E. The comments are included in the administrative record of this Proposed 2007 Determination.

On August 3, 2005, the Department issued its Determination of Revenue Requirements for the period of January 1, 2006 through December 31, 2006 and notified the Commission of the Department’s Revenue Requirements consistent with the Rate Agreement. The August 3, 2005 Determination projected a cash basis revenue requirement that totaled $4.991 billion, which consisted of $4.128 in Department Costs and $0.863 in billion in Bond Related Costs. These amounts reflected a $291 million aggregate reduction when compared to the June 8, 2005 Proposal. The August 3, 2005 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.

Following its August 3, 2005 Determination, the Department reviewed certain matters relating to that Determination, including, but not limited to, operating results of the Electric Power Fund (the "Fund") as of September 30, 2005 (the August 3, 2005 Determination incorporated preliminary actual operating results through April 30, 2005), an updated assumption regarding the interest rate used to calculate interest earnings on account balances, a Bond refunding that was completed on December 1, 2005, the Williams Energy Marketing & Trading Settlement Agreement, and developments in natural gas markets.

The Department's review of the aforementioned considerations resulted in several modifications, which increased the Proposed Revised 2006 Determination (the Proposed Revised 2006 Determination was published and submitted to the Commission on October 17, 2005) by $375 million relative to the August 3, 2005 Determination (the cash basis revenue requirement presented in the August 3, 2005 Determination totaled $4.991 billion). Interested persons were advised to submit comments related to the Proposed Revised 2006 Determination no later than October 24, 2005.

During the period between October 17, 2005, and October 24, 2005, the Department responded to questions in an effort to assist interested persons in the review and understanding of the Proposed Revised 2006 Determination. The Department received no comments on the Proposed Revised 2006 Determination.

On October 27, 2005, the Department published its Final Determination of Revenue Requirements for the period of January 1, 2006 through December 31, 2006 and submitted it to the Commission. The October 27, 2005 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.

Additional detail related to the Final 2006 Determination is provided in the Final 2006 Determination itself, which is included as part of the administrative record supporting this 2007 Proposed Determination.

On December 1, 2005, the Commission adopted Decision 05-12-010, implementing an allocation of the Department's Final 2006 Determination consistent with the permanent allocation methodology adopted in Decision 05-06-060 (Decision 05-06-060 was adopted on June 30, 2005, but applies retroactively to January 1, 2004).[4]

The Department sent requests for information to each IOU on March 22, 2006, which solicited an update of various modeling assumptions and operational considerations. On April 19, 2006, the Department received responses to its requests for information from PG&E, SCE and SDG&E.

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[4] On June 30, 2005, the Commission adopted Decision 05-06-060, which granted a limited rehearing of Decision 04-12-014, as requested by SDG&E. Decision 05-06-060 rendered moot Decision 05-01-036, which previously modified Decision 04-12-014. Decision 05-06-060 adopted the previous allocation of avoidable costs, pursuant to Decision 02-09-053, and separately allocates non-avoidable costs in the following percentages: PG&E 42.2%, SCE 47.5%, and SDG&E 10.3%.

The information obtained from the IOUs, much of which is considered by each individual IOU as confidential and provided under a non-disclosure agreement, serves as the basis for the Department's analytical and forecasting efforts related to this 2007 Proposed Determination. The Department also considered other important criteria, including but not limited to Commission Decisions and Bond Indenture requirements. The resulting data was incorporated into the PROSYM simulation model and the Financial Model, and became a part of the projections leading to this 2007 Proposed Determination.

Upon completion of the procedures set forth in the Regulations, the Department will determine its revenue requirements for the 2007 Revenue Requirement Period.

C. THE DEPARTMENT'S PROPOSED DETERMINATION OF REVENUE REQUIREMENTS FOR THE PERIOD JANUARY 1, 2007 THROUGH DECEMBER 31, 2007

REVENUE REQUIREMENT DETERMINATION

For 2007, 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.

Department Costs include:

(1) Costs associated with power supply to be delivered under the Department's Priority Long-Term Power Contracts ("PLTPCs");

(2) Administrative and general expenses;

(3) Gas collateral and/or hedging costs; and

(4) Changes to Power Charge Account balances, including any amounts required to maintain operating reserves as determined by the Department (see determinations in Table A-1).

Power Charge Account revenues include:

(1) Revenues from other power sales;

(2) Interest earnings on Power Charge Accounts; and

(3) Power Charge Revenues (including both Power Charge Revenues and CRS revenues from customers other than customers of the IOUs and DWR).

There are no provisions included in Department Costs for the procurement by the Department of any of the residual net short during 2007.

During 2007, the Department projects that it will incur the following Department Costs: (a) $4.858 billion for long-term power contract purchases to cover the net short requirement of customers; (b) $26 million in administrative and general expenses; (c) $90 million in gas collateral and/or hedging costs related to and in support of hedging activities of the IOUs on behalf of DWR; and (d) $(236) million in other net changes to Power Charge Accounts (including operating reserves). This projection results in a total revenue need of $4.738 billion.

Funds to meet these costs (in addition to surplus operating reserves) are projected to be provided from (a) $232 million from the Department's share of surplus power sales revenues; (b) $74 million of interest earned on Power Charge Account balances; and (c) $4.432 billion from Power Charge Revenues and 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 2007 Revenue Requirement Period.

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

Line	Description	Amounts for Revenue Requirement Period (Millions of Dollars)				
		2007 - Q1	**2007 - Q2**	**2007 - Q3**	**2007 - Q4**	**Total**
1	*Power Charge Accounts Expenses*					
2	Power Costs	1,278	1,004	1,312	1,264	4,858
3	Administrative and General Expenses	6	6	6	6	26
4	Gas Collateral Costs	-	45	45	-	90
5	Net Changes to Power Charge Account Balances	(30)	(13)	(176)	(17)	(236)
6	**Total Power Charge Accounts Expenses**	**1,255**	**1,043**	**1,187**	**1,254**	**4,738**
7	*Power Charge Accounts Revenues*					
8	Other Power Sales Revenues	86	56	32	58	232
9	Interest Earnings on Power Charge Account Balances	19	19	19	18	74
10	Total Power Charge Revenue Requirement[1]	1,150	968	1,136	1,178	4,432
11	**Total Power Charge Accounts Revenues**	**1,255**	**1,043**	**1,187**	**1,254**	**4,738**

[1]Represents the Department's Retail Revenue Requirement, except to the extent funded by surcharge revenues.

Bond Related Costs include:

(1) Debt service on the Bonds (including related Qualified Swap payments); and

(2) Changes to Bond Charge Account balances.

Bond Charge Accounts revenues include:

(1) Interest earned on Bond Charge Account balances; and

(2) Bond Charge Revenues (including CRS revenues from customers other than customers of the IOUs and DWR).

Table C-2 provides a quarterly projection of costs and revenues relating to the Bond Charge Accounts for the 2007 Revenue Requirement Period.

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

Line	Description	Amounts for Revenue Requirement Period (Millions of Dollars)				
		2007 - Q1	**2007 - Q2**	**2007 - Q3**	**2007 - Q4**	**Total**
1	*Bond Charge Accounts Expenses*					
2	Debt Service Payments	61	619	63	159	901
3	Net Changes to Bond Charge Account Balances	136	(400)	166	78	(20)
4	**Total Bond Charge Accounts Expenses**	**197**	**218**	**229**	**237**	**882**
5	*Bond Charge Accounts Revenues*					
6	Interest Earnings on Bond Charge Account Balances	11	27	10	25	73
7	Retail Customer Bond Charge Revenue Requirement	186	191	220	212	809
8	**Total Bond Charge Accounts Revenues**	**197**	**218**	**229**	**237**	**882**

During 2007, the Department projects that it will incur the following Bond Related Costs: (a) $901 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) $(20) million for changes to Bond Charge Account balances, resulting in total Bond Charge Account expenses of $882 million.

Funds to meet these requirements are provided from (a) $73 million in interest earned on Bond Charge Account balances, and (b) $809 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.

In aggregate, the Department's total cash basis expenses are projected to be $5.876 billion. Revenues from interest earned and other power sales are projected to be $379 million, and net changes in fund balances are projected to be $(256) million, resulting in proposed, combined customer revenue requirements of $5.241 billion.

D. ASSUMPTIONS GOVERNING THE DEPARTMENT'S PROJECTION OF REVENUE REQUIREMENTS FOR THE 2007 REVENUE REQUIREMENT PERIOD

This 2007 Proposed Determination is based 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 2006.[5] The Department reviewed the utilities' underlying forecast assumptions, including population growth, changes in employment and labor within the utility's service area, weather affects, 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 in California. These assumptions are discussed in greater detail below.

Table D-1 shows the 2007 energy requirements forecast (quantified in gigawatt hours) for the PG&E, SCE and SDG&E service areas during 2007.

TABLE D-1
ESTIMATED ENERGY REQUIREMENTS[1]

Service Area	Total Retail Requirements	Direct Access Requirements	Bundled Requirements
Pacific Gas & Electric	92,215	8,149	84,066
Southern California Edison	99,005	10,896	88,110
San Diego Gas & Electric	21,561	3,803	17,758
Total	**212,782**	**22,848**	**189,933**

[1]All values presented include transmission and distribution losses.

DIRECT ACCESS

The Department's direct access estimates are based on data provided by each IOU in April 2006 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. California Water Code § 80110 directs the Commission to suspend direct access until the Department no longer supplies power under Division 27 of the Water Code. Table D-2 shows each IOU's direct access forecast, as a percentage of total retail load, for 2007.

[5] PG&E prepared its forecast in December 2005 and has no near-term plans to update this forecast. SCE prepared its forecast in October 2005 and plans to prepare an update by May 31, 2006. SDG&E prepared its forecast in 2005 and plans to prepare an update by August 2006.

TABLE D-2
2007 DIRECT ACCESS FORECAST[6]

	Percentage of Total Retail Load
Pacific Gas and Electric Company	11.1%
Southern California Edison Company	12.3%
San Diego Gas and Electric Company	17.8%
Statewide	**10.7%**

COMMUNITY CHOICE AGGREGATION

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."[7] Significant volumes of CCA could lead to changes in Department rates to accommodate reduced retail deliveries of Department power.

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. Only a few cities and counties have indicated a willingness to pursue Community Choice Aggregation, including the City and County of San Francisco, several East Bay cities, Chula Vista, Marin County, and Fresno. Although a city or county could implement CCA in 2007, the Department believes this outcome is unlikely and, in any event, is too speculative to forecast. Indeed, all three utilities have forecast no CCA load in 2007.

POWER SUPPLY RELATED ASSUMPTIONS

Three types of power supplies needed to meet the requirements of each IOU were considered by the Department in this 2007 Proposed Determination: (a) IOU supplied resources; (b) supply from the Department's long-term power contracts; and (c) the residual net short of each IOU.[8]

Table D-3 below shows, for the 2007 Revenue Requirement Period, the estimated energy requirements for the customers of the IOUs, estimated supplies from generation by the three IOUs,[9] the resulting net short, the expected supply from the Department's long-term power contracts, off-system energy sales and the residual net short.

[6] Figures in Table D-2 represent direct access as a percentage of total retail load for 2007. These percentages correspond to direct access loads forecast by the IOUs in 2006. The Department assumes that direct access load will remain constant from 2007 to 2008.
[7] Public Utilities Code, Section 331.1(a).
[8] 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 Proposed Determination for the 2007 Revenue Requirement Period. For purposes of this 2007 Proposed 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.
[9] For purposes of this 2007 Proposed 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 ("QF's") and other bilateral contracts.

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

	Amounts for the Revenue Requirement Period (Gigawatt-Hours)
All Investor Owned Utilities	
Energy Requirements After Adjustments[1]	185,132
Supply from Utility Resources	139,948
Net Short	45,184
Supply from the Department's Long-Term Power Contracts	54,439
Off-System Sales	(9,254)
Residual Net Short (Surplus)	11,672

[1]Energy requirements are presented at the ISO level, net of transmission losses.

Table D-4 shows, on a quarterly basis for the 2007 Revenue Requirement Period, estimated net short volumes in gigawatt-hours, supply from the Department's long-term power contracts and the residual net short.

TABLE D-4
NET SHORT, SUPPLY FROM THE DEPARTMENT'S LONG-TERM POWER CONTRACTS, OFF-SYSTEM SALES AND RESIDUAL NET SHORT IN 2007[1]

Period	Net Short (GWh)	Supply from Long-Term Priority Contracts (GWh)	Priority Long-Term 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)
Q1-2007	12,056	13,546	$ 1,245	(3,033)	$ (241)	1,544
Q2-2007	13,330	12,234	$ 1,081	(2,161)	$ (129)	3,258
Q3-2007	17,373	14,676	$ 1,372	(1,583)	$ (119)	4,280
Q4-2007	14,097	13,984	$ 1,279	(2,477)	$ (197)	2,590
Total	56,856	54,439	$ 4,976	(9,254)	$ (685)	11,672

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

UTILITY RESOURCES

The Department reviewed each utility's 2007 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 2007 and 2008. Neither the CEC nor the National Weather Service Northwest River Forecast

Center has provided meaningful forecasts past the 2006 water year. Therefore, DWR has projected normal hydroelectric dispatch for the 2007 Revenue Requirement Period.

With respect to the 2006 water year, the Department expects above normal hydro output during the period between May and August. Any impacts related to actual hydro operations will be reflected when the Department revises its assumptions later this year.

CONTRACT ASSUMPTIONS

During the 2007 Revenue Requirement Period, approximately 54,439 GWhs of energy is projected to be supplied to 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 Utility'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 economic considerations to achieve the lowest possible total cost of power to IOU customers. 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 market clearing prices.

Table D-5 provides a listing of all of the long-term power contracts that will be operational during the 2007 Revenue Requirement Period and beyond, describing the term and capacity associated with each contract and the IOU to which the contract has been allocated. With respect to the Department's long-term power contract with Williams Energy Marketing & Trading ("Williams"), Product D, this contract has been reallocated to SCE effective January 1, 2007. This reallocation is based on CPUC Decision 05-12-021, dated December 15, 2005, which reallocated the 1,175 MW (dispatchable capacity in calendar year 2007) Williams' Product D contract from SDG&E to SCE and addressed the allocation of DWR's long-term power contracts with Kings River Conservation District and the City and County of San Francisco. Regarding the Amended and Restated Demand Reserves Purchase Agreement with the California Power Conservation and Financing Authority, projected costs for the 2007 Revenue Requirement Period are zero, as the contract expires in May 2007, prior to the summer season. 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
CalPeak Power—Panoche, LLC	8/14/2001 Renegotiated on 5/2/02	12/27/2001	12/27/2011	50.8	PG&E
CalPeak Power--Vaca Dixon, LLC	8/14/2001 Renegotiated on 5/2/02	6/21/2002	12/31/2011	50.8	PG&E
CalPeak Power--El Cajon, LLC	8/14/2001 Renegotiated on 5/2/02	5/29/2002	12/31/2011	52	SDG&E
CalPeak Power—Border, LLC	8/14/2001 Renegotiated on 5/2/02	12/12/2001	12/12/2011	51.3	SDG&E
CalPeak Power—Enterprise, LLC	8/14/2001 Renegotiated on 5/2/02	12/8/2001	12/8/2011	48	SDG&E
Calpine Energy Services, L.P. (Firm)	2/6/2001 Renegotiated on 4/22/02	1/1/2004	12/31/2009	1000	PG&E
Calpine Energy Services, L.P. (Long Term Commodity Sale)	2/26/2001 Renegotiated on 4/22/02	7/1/2002	12/31/2009	1000	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
Clearwood Electric Company, LLC	6/22/2001 Renegotiated on 7/2/04	Upon COD, est. 6/2007	12/31/2012	30	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
Goldman Sachs Group, Inc. (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	94.8	PG&E
"	"	7/1/2002	12/31/2011	96.7	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

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
Kings River Conservation District	12/31/2002 Renegotiated 8/18/04	9/19/2005	9/18/2015	97.2	PG&E
Mountain View Power Partners, LLC	5/31/2001 Renegotiated on 10/1/02	10/1/2001	9/30/2011	66.6	SCE
PacifiCorp	7/6/2001	7/1/2004	6/30/2011	300	PG&E
City/County of San Francisco	12/30/2002	Unknown		Est. 180	Est. PG&E
Sempra Energy Resources	5/4/2001	1/1/2004	9/30/2011	1200; drops to 800 in Mar-May of 2004-2007	SCE
"	"	1/1/2004	9/30/2011	700; drops to 400 in Mar-May of 2004-2007, and permanently starting Jan 2008	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	21.3	PG&E
Wellhead Power Gates, LLC	8/14/2001 Renegotiated on 12/17/02	12/27/2001	10/31/2011	46.5	PG&E
Wellhead Power Panoche, LLC	8/14/2001 Renegotiated on 12/17/02	12/14/2001	10/31/2011	49.9	PG&E
Whitewater Energy Corp. (Cabazon Project)	7/12/2001 Renegotiated on 4/24/02	8/31/2002	12/31/2013	43	SDG&E
Whitewater Energy Corp. (Whitewater Hill Project)	7/12/2001 Renegotiated on 4/24/02	8/31/02 (partial)	12/31/2013	65	SDG&E
Williams Energy Marketing & Trading	2/16/2001 Renegotiated on 11/11/02	7/1/2003	12/31/2007	200	SDG&E
"	"	1/1/2006	12/31/2007	450	SDG&E
"	"	1/1/2008	12/31/2010	275	SDG&E
"	"	7/1/2003	12/31/2010	50	SDG&E

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
"	"	7/1/2003	12/31/2007	1175	SCE in 2007
"	"	1/1/2008	12/31/2010	1045	SCE in 2007

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.

The Department has renegotiated 19 of the original contracts entered into in 2001 that remain effective in 2007 or beyond, and has terminated five additional contracts for cause. The Department has continued efforts to renegotiate additional contracts. The Department regularly monitors its contracts to determine if there are other opportunities for bilateral renegotiation, which could lead to more favorable power supply terms and costs.

Theoretically, the Department could 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. For this reason, under present market conditions and terms of the contracts, the Department does not believe that termination of any of the contracts would result in a reduction in its revenue requirements or overall ratepayer costs.

ADDITIONAL CONTINGENCIES

On December 20, 2005, Calpine Corporation filed petitions to restructure under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for New York's Southern District. As part of its restructuring efforts, Calpine requested the rejection of Calpine 2, one of its long-term power contracts with the Department.

Prior to Calpine's filing with the U.S. Bankruptcy Court, the Department initiated proceedings at FERC to require Calpine to continue to perform under the Calpine 2 contract in order to protect

California ratepayers. The Department also filed a motion with the United States District Court for the Southern District of New York to withdraw the reference to Bankruptcy Court from Calpine's request to reject the Calpine 2 contract. The District Court granted the Department's motion to withdraw the reference and then dismissed Calpine's motion to reject the Calpine 2 contract and other energy contracts. Calpine subsequently appealed the District Court's order to the United States Court of Appeals for the 2nd Circuit. Since Calpine's appeal and subsequent litigation could potentially result in the rejection of this 1,000 megawatt power contract, the Department is actively engaged in various efforts, including litigation, to protect the mark to market value of this contract to the ratepayer.

As referenced in Table D-5 (above), the Calpine 2 long-term power contract is currently allocated to PG&E and provides 1,000 megawatts of must-take power, 24x7, at a rate of $59.60/MWh (approximately 40% of the Department's energy deliveries to PG&E's service territory). The term of Calpine 2 will naturally expire December 31, 2009.

As previously noted, the Department has and will continue to actively participate in Calpine's bankruptcy proceedings to protect the value of the Calpine 2 contract for California ratepayers and because revenue requirement allocation issues would arise in the event of Calpine 2 rejection. Rejection of the Calpine 2 contract would also result in a termination payment to the Department, the timing and amount of which would likely be determined by the terms of Calpine's Plan of Reorganization. Calpine is not expected to seek approval of a Plan of Reorganization until Spring 2007. Any developments in this proceeding that may affect the Department's revenue requirement for the 2007 Revenue Requirement Period will be addressed when the Department updates its assumptions later this year.

COST RESPONSIBILITY SURCHARGE

In a series of decisions, the Commission ordered certain classes of direct access, municipal and customer generating departing load, and community choice aggregation customers to pay a Cost Responsibility Surcharge ("CRS") related to historical stranded costs and ongoing above-market bundled costs associated with the Department's contracts. Included in the CRS is the DWR Bond Charge component, which is assessed to pay debt service associated with the Department's 2002 bond issuance, and the DWR Power Charge component, which pays a portion of the above-market costs related to the DWR power portfolio.

Payments by direct access load, departing load, and CCA load of the DWR Bond Charge and the DWR Power Charge flow to the Department through Commission-established rates assessed on total usage. These revenues reduce one-for-one the bundled customer responsibility for DWR Bond Related Costs and Department Costs, respectively. In 2007, DWR Power Charge collections from direct access are limited by a maximum collections rate, or cap, established by the Commission.[10] Differences in the collection and accrual rate for the DWR Power Charge CRS are funded by bundled customers.[11]

[10] SDG&E has received authority to temporarily suspend collection of the DWR Power Charge component of the CRS. It is also possible that PG&E may lift its CRS cap later this year. DWR continues to monitor Commission proceedings addressing these matters.
[11] Undercollections from direct access are tracked in a balancing account and are returned to bundled customers when the collections cap exceeds the accrual rate.

SALES OF EXCESS ENERGY ASSUMPTIONS

As with any retail provider of energy, the Department and IOUs together, from time to time, purchase 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 losses are an expected incident of appropriate 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, Interim Opinion on Procurement Issues: DWR Contract Allocation. This Decision allocated each of the thirty-five long-term power contracts to a specific IOU. Decision 02-09-053 also determined that 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 (GWh)	IOU Volume (GWh)	Total Volume (GWh)	DWR Revenue (Millions of Dollars)	IOU Revenue (Millions of Dollars)	Total Revenue (Millions of Dollars)	Weighted Average Price ($/MWh)
Q1-2007	959	2,074	3,033	$ 78	$ 163	$ 241	$ 79
Q2-2007	623	1,538	2,161	$ 39	$ 90	$ 129	$ 60
Q3-2007	493	1,089	1,583	$ 38	$ 81	$ 119	$ 75
Q4-2007	781	1,696	2,477	$ 63	$ 134	$ 197	$ 79
Total	2,857	6,397	9,254	$ 218	$ 467	$ 685	$ 74

[1]All revenues presented on an accrual basis.

An alternative operating scenario, considered by the Department for the 2007 Revenue Requirement Period, evaluated the effects of discontinuing surplus sales revenue sharing between the Department and the IOUs. In previous Revenue Requirement Periods, the income from surplus energy sales was used to partially offset the revenue requirements of the Department and the IOUs that would otherwise be recovered from retail customers. In this operating scenario, all energy from the Department's long-term energy contracts is deemed delivered to retail end use customers, and each IOU retains all surplus sales revenues. This scenario results in a simplified operational reporting process for DWR's power supply program and the IOUs' administration of DWR's long-term contracts.

The projected effects of this operational change, relative to the Base Case proposed herein, include: (1) a reduction in Surplus Sales Revenue of $218 million (a portion of Other Revenue is related to surplus energy sales from 2006); and (2) an increase in total required operating reserves of $234 million. The increase in operating reserves is due to the volatility resulting from the lack of the mitigating effect of higher market clearing prices in a high gas price environment (stress case) on the Department's cash flows exposing the Department to the full effect of high gas prices on its portfolio of contracts. The reduction in surplus sales revenue and the need to increase reserves due to increased operational volatility result in a projected increase in required Power Charge Revenues of $452 million for the 2007 Revenue Requirement Period. A corresponding possible decrease in the IOU's revenue requirement that the Department estimates at $218 million would partially reduce the overall effect of this change on the ratepayers within the service territories of each IOU. The projected increase in Power Charge Revenues will be collected on increased energy deliveries by the Department to end use customers, leaving the overall Power Charge rate comparable to (or slightly lower than) the rate reflected in this 2007 Proposed Determination. In this scenario, the DWR Bond Charge remains unaffected. While this operating scenario may affect future revenue requirement periods, the Department has assumed that this scenario will not be implemented during the 2007 Revenue Requirement Period.

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 2007. 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 purchases, are projected to be $4.976 billion for the 2007 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 2007 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 Power Contracts
Q1 – 2007	$90
Q2 – 2007	$86
Q3 – 2007	$92
Q4 – 2007	$90

NATURAL GAS PRICE FORECAST AND FUELS ASSUMPTIONS

The natural gas price forecast supporting this 2007 Proposed Determination is based on a forecast prepared by Navigant Consulting, Inc. ("NCI"), consultants to DWR, using the Gas Market Data and Forecasting System owned by Energy and Environmental Analysis, Inc. ("EEA"), with certain assumptions specified by NCI. These assumptions include the timing of major gas pipeline capacity changes, the prices of crude oil and coal and the timing and magnitude of certain liquefied natural gas ("LNG") capacities, imports and exports. The EEA model uses a structural, network simulation of the natural gas markets in the U.S. and Canada to solve for natural gas production volumes, gas demand by sector, gas flows, storage activity, and gas prices at over 100 market "nodes" in North America.

The initial model results are then reviewed by NCI and compared with NYMEX forward prices. Based on NCI's review of the initial price forecast at Henry Hub, DWR determined that a price adjustment at this node was necessary to reflect current observations in natural gas markets. For the gas price forecast underlying this 2007 Proposed Determination, the annual price at Henry Hub was calculated in late April 2006 by averaging the current month's daily settlement prices of the 12 NYMEX contracts for deliveries in 2007. The difference between the initial annual average price forecast at Henry Hub and the recalculated average annual price was used to proportionately adjust the forecasted prices at other market nodes, including PG&E Citygate and the Southern California Border.

The right to use EEA's modeled price output was obtained by NCI under contract with EEA. This model is used by NCI for all of its electric market assignments.[12] The Department has determined to use the EEA model because it simulates the fundamental market dynamics that, at times, are not reflected in forward gas prices, particularly those beyond 12-18 months. The base case gas forecast supporting this 2007 Proposed Determination was prepared based on the NCI-EEA model run dated February 2006. The DWR forecast will be run twice annually or more often, as required, to reflect revised market conditions and assumptions.

Compared to the base case forecast underlying the Final 2006 Determination, prices in the base case forecast supporting this 2007 Proposed Determination are shown in Table D-8.

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

	2007	2008
Gas Price Forecast – 2007 Proposed Determination	$10.10	$9.22
Gas Price Forecast – Final 2006 Determination	$9.30	$8.06
Difference	$0.80	$1.16

Table D-9 below lists the updated natural gas prices by quarter for 2006 and 2007 at two key California pricing hubs: PG&E Citygate and the Southern California Border.

[12] Prior to the 2006 Revenue Requirement, forecasts for DWR had been prepared by NCI based upon a proprietary forecast model.

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

	Southern California Border		**PG&E Citygate**	
	2007	**2008**	**2007**	**2008**
Q1	$10.61	$9.22	$10.77	$9.40
Q2	$9.02	$8.32	$9.14	$8.60
Q3	$9.11	$8.61	$9.21	$8.76
Q4	$9.93	$9.12	$10.08	$9.29
Annual Average	**$9.67**	**$8.82**	**$9.80**	**9.01**

ADMINISTRATIVE AND GENERAL COSTS

The Department's administrative and general costs of $26 million consist of $21 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 $5 million for consulting services for development and monitoring of the revenue requirements, litigation support, and financial advisory services for managing the $11 billion debt portfolio and related reserves.

GAS HEDGING EXPENSE

For the 2007 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 on April 19, 2006, individual IOU fuel supply plans, specifically Gas Supply Plan VII ("GSP VII"), and the Department's own internal analysis.

The Department estimates that as of April 30, 2006, the IOUs had collectively secured, or developed reasonably firm plans to secure, hedges on behalf of DWR that establish the effective price for 114 million MMBtu during calendar year 2007. The hedged volume of 114 million MMBtu represents approximately 55% of total projected IOU gas requirements (for fuel related to allocated DWR power contracts) for the 2007 Revenue Requirement Period. In addition to these hedges, the Department has effectively hedged 18 million MMBtu of natural gas via firm price deliveries from the Williams contract during both the 2007 and 2008 Revenue Requirement Periods.

For purposes of the 2007 Proposed Determination, all proposed NYMEX hedges use the margin requirement price for gas contracts and the price for basis swaps quoted on June 7, 2006 on the NYMEX. The IOUs and the Department plan to augment NYMEX hedges with a portfolio of call and spread options. The total gas hedging expense for the 2007 Revenue Requirement is projected to be $90 million.

FINANCING RELATED ASSUMPTIONS

In October and November 2002, the Department issued $11.263 billion of Power Supply Revenue Bonds. The primary uses of net Bond proceeds were to (a) repay the then-outstanding balance of the $4.3 billion Interim Loan entered into by the Department with commercial lenders, the proceeds of which were used to fund 2001 power costs; (b) reimburse the State's General Fund for approximately $6.1 billion advanced to the Department for 2001 power purchases and interest that had accrued on the General Fund advances, and (c) fund reserves required to complete the bond financing.

The details of the Bond financing structure were made public in connection with the Department's 2003 Revenue Requirement filing and are described in the Bond Indenture and the Supplemental Bond Indentures for each series of Bonds.

On December 1, 2005, the Department completed a refinancing of a portion of its fixed rate bonds (Series 2002A) issued in 2002. The refinancing consisted of the issuance of $2.594 billion of variable rate debt and the simultaneous execution of an equal notional amount of interest rate hedging agreements (swaps) to convert the Department's variable interest rate exposure on the new bonds to fixed rate exposure. Debt service savings resulting from the refinancing are projected to average approximately $16 million per year from 2006 through 2022.

For purposes of calculating the interest earnings on account balances, the Department assumes a 4.90% earnings rate for the Debt Service Reserve Account and a 4.30% earnings rate for all other accounts during the 2007 Revenue Requirement Period.

For purposes of calculating the interest accruing on Variable Rate Bonds during 2007, as well as any future revenue requirement periods, interest is assumed to accrue at a rate equal to the greater of (a) 130% 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%. For the 2007 Revenue Requirement Period, the interest rate on Variable Rate Bonds is projected to be 4.08%.

The Department projects that the amount of Bond Charge Revenues required for the 2007 Revenue Requirement Period will be $809 million.

ACCOUNTS AND FLOW OF FUNDS UNDER THE BOND INDENTURE

The Rate Agreement and Summary of Material Terms with all applicable addenda are reflected in the Bond Indenture. The following is a description of the funds and accounts that are required as part of the Bond program.

Revenues are held in and accounted for in the Electric Power Fund established under the Act. The Bond Indenture established two sets of accounts for Revenues within the Electric Power Fund. In the following description of accounts and the flow of funds, capitalized terms refer to terms that are further defined in the Indenture.

One set of accounts is primarily for the deposit of Power Charge Revenues and the payment of Operating Expenses (including payments of Priority Contract Costs and other power purchase costs and other costs of the Power Supply Program) (collectively, the “Power Charge Accounts”):

- The Operating Account,
- The Priority Contract Account,
- The Operating Reserve Account, and
- The Administrative Cost Account.

The other set of accounts is primarily for the deposit of Bond Charge Revenues and the payment of Bond Related Costs (collectively, the “Bond Charge Accounts”):

- The Bond Charge Collection Account,
- The Bond Charge Payment Account, and
- The Debt Service Reserve Account.

The Bond Indenture requires all Bond Charge Revenues to be deposited in the Bond Charge Collection Account and all Power Charge Revenues and other Revenues (other than Bond Charge Revenues) to be deposited in the Operating Account.

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 (See Section B “Background—The Act”).

The Department determines the MOEAB at the time of each revenue requirement determination and, when the Department is not procuring the residual net short, 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 2007 Proposed Determination, the Department has determined the MOEAB to be $376 million. The Department projects to exceed the MOEAB at all times during 2007. 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”.

PRIORITY CONTRACT ACCOUNT

The Priority Contract Account is used to pay the costs the Department incurs under its Priority Long Term Power Contracts, which have terms that require the Department to pay for power purchased under these contracts ahead of Bond Related Costs. On or before the fifth Business Day of each month, the Department is required to transfer from the Operating Account to the Priority Contract Account such amount as is necessary to make the amount in the Priority Contract Account sufficient to pay Priority Contract Costs estimated to be due during the balance of such month and through the first five Business Days of the next succeeding calendar month. Amounts in the Priority Contract Account may be used solely to pay Priority Contract Costs.

For the 2007 Revenue Requirement Period it is projected that the Priority Contract Account will have sufficient funds available from the Operating Account, and that no transfer from Bond Charge Collection Account to the Priority Contract Account will be required.

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, in the case of clause (i) above, may take into account a range of possible future outcomes (i.e., “stress cases”).

Based on the “stress” operating conditions (later described in the “Sensitivity Analysis” portion of Section D), the ORAR for the 2007 Revenue Requirement Period is determined by the Department to be $595 million, reflecting an amount equal to 12% of the most recent 12-month period for which reasonably full and complete Operating Expense information is available (May 2005 through April 2006), adjusted in accordance with the Indenture to the extent the Department no longer is financially responsible for particular Power Supply Contracts.

BOND CHARGE COLLECTION ACCOUNT

All Bond Charge revenues will be deposited in the Bond Charge Collection Account. Subject to the prior claim on revenues in the Bond Charge Collection Account for the payment of Priority Contract Costs, on or before the last Business Day of each month, the Department is required to transfer from the Bond Charge Collection Account to the Bond Charge Payment Account such amount as is necessary to make the amount in the Bond Charge Payment Account sufficient to pay Bond Related Costs (including debt service on the Bonds and all other Bond Related Costs) estimated to accrue or to be due and payable during the next succeeding three calendar months.

The minimum balance to be maintained from time to time within the Bond Charge Collection Account is determined to be an amount equal to one month’s required deposit to the Bond

Charge Payment Account. As required by the Bond Indenture, the Department assumes interest costs on unhedged Variable Rate Bonds during the 2007 Revenue Requirement Period at 4.0 percent for the purpose of calculating required deposits to the Bond Charge Payment Account. For the 2007 Revenue Requirement Period, the minimum account balance amount ranges from $75 to $76 million.

BOND CHARGE PAYMENT ACCOUNT

The Bond Charge Payment Account is calculated as an amount equal to the debt service accrued and unpaid through the end of the third next succeeding calendar month. The Department assumes interest costs on unhedged Variable Rate Bonds during the 2007 Revenue Requirement Period at 4.0 percent for the purpose of calculating debt service accruals in the Bond Charge Payment Account. For the 2007 Revenue Requirement Period, the minimum account balance amount ranges from $311 to $810 million.

DEBT SERVICE RESERVE ACCOUNT

The "Debt Service Reserve Requirement" is an amount equal to maximum aggregate annual debt service on all outstanding Bonds, determined in accordance with the Bond Indenture. The Debt Service Reserve Account is required by the Bond Indenture to be funded in the amount of the Debt Service Reserve Requirement, initially with proceeds from the sale of the Bonds (or Alternate Debt Service Reserve Account Deposits referred to below, or a combination of both) and subsequently maintained and replenished, if necessary, from Power Charge Revenues or Bond Charge Revenues.

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 2007 Revenue Requirement Period, the Department will calculate projected interest on unhedged Variable Rate Bonds at 4.08 percent.

Alternate Debt Service Reserve Account Deposits may be made to the Debt Service Reserve Account in lieu of cash and/or securities. Such deposits may consist of irrevocable surety bonds, insurance policies, letters of credit or similar obligations. The Department is not currently assuming the use of Alternate Debt Service Reserve Account Deposits.

For the 2007 Revenue Requirement Period, the Department has determined the Debt Service Reserve Requirement to be $913 million.

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 cash flow projections based on changes in certain key expense and operating assumptions ("Stress Cases"). 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-10. This Stress Case gas price forecast 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 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
	2007	**2007**	**2007**
Q1 – 2007	$19.35	$19.71	$19.68
Q2 – 2007	$15.58	$16.47	$16.43
Q3 – 2007	$15.80	$16.63	$16.58
Q4 – 2007	$17.21	$18.34	$18.31
Annual Average	**$16.99**	**$17.79**	**$17.75**

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 April 2006 for each delivery point and identifying 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 April 30, 2006. 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, 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% of normal for 2007 and 2008.

Lower loads are estimated in this case by assuming cooler-than-normal summers during 2007 and 2008, 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 2007 and 2008 by 3.3%, 3.6%, 5.1% and 4.4% 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 4% in 2007 and 2% in 2008. 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, and includes the impact of actual and planned gas hedges in place as of April 30, 2006.

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% of normal in 2007 and 2008. URG is further decreased by assuming an unplanned outage at one southern California nuclear power plant unit from January 2007 through March 2007 and at one northern California nuclear power plant unit from April 2007 through March 2008. In addition, approximately 650 MW of merchant generation resources in northern California and 1500 MW of merchant generation resources in southern California that are assumed to be available to the market in the Base Case are assumed to be retired for the entire Revenue Requirement Period in this Stress Case. 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 2007 and 1.4% higher in 2008. It is assumed that this growth occurs as a result of accelerated economic growth in California and decreases in the expected amount of non-programmatic conservation. In addition, load is increased by assuming the existence of warmer-than-normal summers in 2007 and 2008. 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 2007 and 2008 by 4.4%, 4.8%, 6.8%, and 5.9% for June, July, August, and September, respectively.

E. POWER CONTRACT SETTLEMENT AND LITIGATION 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. These settlement distributions reduce Department costs and, as a result, decrease the Department's revenue requirement. The following settlement agreements have been considered in projecting the Department's beginning account balances and costs for the 2007 Revenue Requirement Period.

ENRON SETTLEMENT AGREEMENT

On August 24, 2005, the State of California, Office of the Attorney General, executed a Master Settlement Agreement with Enron Corporation that has resulted in the Department's receipt of more than $50 million during the 2006 Revenue Requirement Period (five payments were received via wire transfer between the dates of January 26, 2006 and May 3, 2006). The State's settlement with Enron Corporation resolves claims that primarily relate to energy overcharges against California ratepayers during 2000 and 2001. The settlement was approved by the Federal Energy Regulatory Commission (FERC) on November 15, 2005.

For the purposes of this 2007 Proposed Determination, the Department has reflected the aforementioned receipts in its starting account balance for the 2007 Revenue Requirement Period. An additional, semi-annual distribution related to unsecured bankruptcy claims is expected to be received from Enron Corporation in October 2006. Since the collection of future amounts can not be estimated and the disbursement of any funds in October 2006 is tentative, no amount is reflected in the Department's beginning account balance for the 2007 Revenue Requirement Period. However, the Department intends to update its revenue requirements for 2007 later this year. If further revenues are received from Enron, the Department will reflect these receipts in its starting account balance for the 2007 Revenue Requirement Period.

MIRANT CORPORATION SETTLEMENT AGREEMENT

On January 14, 2005, the State of California, Office of the Attorney General, executed a Master Settlement Agreement with Mirant Corporation, which was approved by the Federal Energy Regulatory Commission (FERC) on April 13, 2005. The State's settlement with Mirant Corporation resolved claims related to energy overcharges against California ratepayers during 2000 and 2001. On June 17, 2005, the Department received over $76 million as part of the aforementioned settlement agreement. This receipt was reflected in the Department's starting account balance for the 2006 Revenue Requirement Period, as noted in the Final 2006 Determination.

Additional amounts were owed to the Department as part of its settlement agreement with Mirant, and on December 29, 2005, the Department received nearly $96 million related hereto.

The source of these funds was the sale by the California Parties, which included the Department, of their unsecured claims totaling $189.4 million (unsecured claims were surrendered as part of the January 14, 2005 settlement agreement for Mirant's alleged misconduct during the 2000-2001 energy crisis). Due to the lack of certainty relating to the amount and timing of the sale of the unsecured claim, this amount was not reflected in the Department's Final 2006 Determination but is reflected in the starting account balance for the 2007 Revenue Requirement Period.

RELIANT ENERGY SETTLEMENT AGREEMENT

On October 12, 2005, the State of California, Office of the Attorney General, executed a Settlement and Release of Claims Agreement with Reliant Energy that has, as of May 31, 2006, resulted in the Department's receipt of more than $66 million during the 2006 Revenue Requirement Period (three payments were received via wire transfer between the dates of January 9, 2006 and March 8, 2006). The amount of more than $66 million results from three separate payments in the amounts of approximately $8 million, $18 million and $40 million, which were received via wire transfer on the dates of January 9, 2006, January 27, 2006 and March 8, 2006, respectively. Similar to the State's settlement agreements with Enron and Mirant, the Reliant Energy settlement also resolves claims that primarily relate to energy overcharges against California ratepayers during 2000 and 2001. The settlement was approved by the Federal Energy Regulatory Commission (FERC) in December 2005.

For the purposes of this 2007 Proposed Determination, the Department has reflected these receipts in its starting account balance for the 2007 Revenue Requirement Period.

SEMPRA ENERGY RESOURCES ARBITRATION

On February 19, 2004, the Department filed a Demand for Arbitration against Sempra with the American Arbitration Association, alleging breach of contract.. On April 18, 2006, the arbitration panel issued an Opinion and Award in which the Department was awarded damages. The actual amount of damages received by the Department resulting from the arbitration panel's Opinion and Award was more that $73 million, which was received by the Department on May 2, 2006 and is reflected in the starting account balance for the 2007 Revenue Requirement Period. The arbitration panel's ruling also governs Sempra's operations over the remaining term of its long-term contract with the Department that will likely save ratepayers millions of dollars over the remaining five years of the contract term.

The Department also has two additional, separate challenges pending against Sempra, which target Sempra's failure to construct a power plant as originally promised and the scheduling practices at its power plant in Mexicali, Mexicor. The first challenge, which is scheduled to go to trial later this year before the San Diego County Superior Court, seeks to terminate the contract. The second challenge is pending arbitration.

WILLIAMS ENERGY MARKETING & TRADING SETTLEMENT AGREEMENT

On November 11, 2002, the State of California, Office of the Attorney General, executed a Settlement Agreement with Williams Energy Marketing and Trading ("Williams") that resulted in the renegotiation of the original Power Purchase Agreements between the Department and

Williams as well as the development of a Natural Gas Purchase Contract between the Department and Williams (natural gas deliveries began on January 1, 2004). 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 (62% in 2007) and SDG&E (38% in 2007).

During the 2007 Revenue Requirement Period, it is projected that the Natural Gas Purchase Contract will result in power cost savings of approximately $98 million, based on the difference between the contract fuel price of $4.09 and the Department's projected, weighted average fuel price of $9.55 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 2007. The projected power cost savings of $98 million is reflected in this 2007 Proposed Determination as a negative Extraordinary Contract Expense, as displayed above in Table A-1.

F. KEY UNCERTAINTIES IN THE PROPOSED REVENUE REQUIREMENT DETERMINATION

There are a number of uncertainties facing the Department that may require material changes to its revenue requirements for the 2007 Revenue Requirement Period after this Proposed 2007 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; and
    b. Gas transmission constraints.

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.

THE DETERMINATIONS FOR 2001, 2002 AND 2003

On August 16, 2002, the Department issued its Determination of Revenue Requirements for the period January 1, 2003 through December 31, 2003 with Reexamination and Redetermination for the period January 17, 2001 through December 31, 2002 (the "August 16, 2002 Determination").

On August 19, 2004, the Department issued a Reconsideration of the Just and Reasonableness of its August 16, 2002 Determination.

THE 2003 SUPPLEMENTAL DETERMINATION

On July 1, 2003, the Department issued a Supplemental Determination for the 2003 Revenue Requirement Period.

THE 2004 DETERMINATION

The 2004 Determination was issued on September 18, 2003.

THE 2004 SUPPLEMENTAL DETERMINATION

On April 16, 2004, the Department issued a Supplemental Determination for the 2004 Revenue Requirement Period.

THE 2005 DETERMINATION

The 2005 Determination was issued on November 4, 2004.

THE REVISED 2005 DETERMINATION

On March 16, 2005, the Department issued a Revised Determination for 2005.

THE 2006 DETERMINATION

The 2006 Determination was issued on August 3, 2005.

THE FINAL 2006 DETERMINATION

Subsequent to its publication of the August 3, 2005 Determination, new information became available to the Department. This new information resulted in the issuance of the Final 2006 Determination on October 27, 2005. The October 27, 2005 Determination provided extensive material leading to the determination by the Department that its revised revenue requirement for 2006, as determined therein, was just and reasonable. In finding the October 27, 2005 Determination to be just and reasonable, the Department discussed the long-term power purchase contracts entered into by the Department, including existing market conditions, the portfolio planning process, the procurement activities and other factors leading to the Determination. That information is, to the extent applicable and not modified herein, incorporated in this Proposed 2007 Determination. For further information please refer to Section I.

THE DEPARTMENT WILL MAKE A JUST AND REASONABLE DETERMINATION AFTER COMPLETION OF ITS ADMINISTRATIVE 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.

The Department issues this Proposed Determination of Revenue Requirements for the period January 1, 2007, through December 31, 2007 for public comment under the Regulations promulgated pursuant to the California Administrative Procedures Act. Under the Regulations, any determination that this 2007 Proposed Determination is just and reasonable will be made by the Department after review of comments from interested persons. The administrative process may result in the issuance of a determination of revenue requirements for 2007 that differs from this 2007 Proposed Determination.

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. The PROSYM price forecasting and market simulation tool was used in this analysis.

PROSYM is a widely accepted tool for simulating detailed power market activity and has a large market presence in the industry. According to its vendor, 80 percent of the major utilities in North America and many utilities in Europe, Asia, and Australia license PROSYM. It has been used to provide analytical support and to forecast market prices and revenues in a large number of financing transactions for merchant power plants and has gained strong acceptance in the financial community.

PROSYM is a detailed chronological model that simulates hourly operation of WECC generation and transmission resources. Within its simulation framework, PROSYM dispatches generating resources to match hourly electricity demand and establishes market-clearing prices based upon incremental resources used to serve load. Demand and energy forecasts used by PROSYM are developed and provided by the vendor. Annual updates of these forecasts are provided by the vendor based on data obtained from EIA filings and independent analysis by the vendor. For purposes of this 2007 Proposed Determination, the demand and energy forecasts used were those that were described in Section D.

In its hourly dispatch, PROSYM reflects the primary engineering characteristics and physical constraints encountered in operating generation and transmission resources, on both a system-wide and individual unit basis. Within PROSYM, thermal generating resources are characterized according to a range of capacity output levels. Generation costs are calculated based upon heat rate, fuel cost, and other operating costs, expressed as a function of capacity output. Physical operating limits related to expected maintenance and forced outage, start-up, unit ramping, minimum up and down time, and other related characteristics are reflected in the PROSYM simulation.

Hydroelectric resources are also characterized in PROSYM according to expected output levels, including monthly forecasts of expected energy production. PROSYM schedules run-of-river hydroelectric production based upon the minimum capacity rating of the unit. The dispatch of remaining hydroelectric energy is optimized on a weekly basis by scheduling hydro production in peak demand hours when it provides the most value to the electrical system.

Within the PROSYM framework, regional market-clearing prices are established based upon the incremental bid price of the last generating station needed to serve demand. For most of the existing supply, bid prices are composed primarily of incremental production costs. Hourly energy revenues for each generating unit are established as the product of market-clearing prices and the unit's energy production during the relevant hour. The PROSYM framework mirrors a “single-price” auction, so that each generator located within the same market area receives an identical price for its energy output, regardless of its actual bid price or production cost.

While the only “single-price” market auction that still exists in California is the CAISO imbalance energy market, this pricing mechanism is modeled as a proxy for the average price of the residual net short. In the long term, under a balanced supply and demand market, the average residual net short price should approximate the market-clearing price in an “as-bid” environment. In the near-term, the use of a single-price mechanism for the residual net short produces a reasonable assessment of market prices.

Based upon the bid price of the marginal generating station in a given hour, the market-clearing price is calculated using the following general approach (stated in dollars per MWh):

Market-Clearing Price = Incremental Production Cost + Start Cost + No-Load Cost + Price Markup

Where:

- Incremental Production Cost is calculated as each station’s fuel price multiplied by the incremental heat rate, plus variable operations and maintenance cost;
- Start Cost incorporates fuel costs and other operating costs encountered in starting the generating unit, beyond those reflected in the heat rate and variable operating cost assumptions;
- No-Load Cost reflects the difference between average and incremental fuel costs for generating stations that are dispatched at less than full output; and
- The Price Markup factor recognizes that market forces may drive bid prices above variable production costs. The Department uses this factor to reflect observed market behavior where wholesale prices often rise above the underlying cost of production, particularly during times when supply/demand margins are tight. Such behavior is common in power markets.

Price Markups are assigned to individual generators depending upon the underlying fuel efficiency, production cost, and technology type. The specific Price Markups are designed so that bid prices rise above the cost of production as less efficient resources are called upon for power production and as the intersection of supply and demand occurs at higher points on the supply curve. The level of Price Markups is determined through an iterative approach with the goal of benchmarking against recent actual wholesale prices, and against observable prices in the forward market.

Three specific bidding strategies were assigned:

1) Incremental Cost Bidding: Units assigned incremental bidding strategies incorporate only variable operating costs into their bid prices. This bidding strategy reflects a highly competitive market structure. All base load resources and generators with

relatively low production costs are assigned this bidding strategy, which reflects the bulk of available supply resources.

2) Price Markup Bidding: Units assigned Price Markup bidding strategies submit bids close to variable operating costs during all off-peak hours. During on-peak periods, when electricity demand is higher, these stations seek to markup price in proportion to the level of electricity demand. The price markups also vary by season, and are at higher levels during the summer and winter periods when supply/demand balances are the tightest. Intermediate-type generating resources such as older steam turbine units having relatively high production costs are assigned this bid strategy.

3) Peak Period Bidding: Units assigned Peak Period bidding strategies also submit close to variable operating costs during off-peak hours. Price markups are assigned to these resources during on peak hours and seasonally. The markups for resources in this category tend to be higher than those applied under the Price Markup strategy. Resources that are assigned Peak Period bidding strategies tend to have the highest production costs, such as simple-cycle gas turbine generators and internal combustion oil-fired plants. Such resources are called upon to produce power only a small portion of the time each year.

The table below provides an overview of bid strategy assignment used in the analysis underlying this determination. As shown, bid prices are set for a majority of supply resources based on incremental production costs.

CALIFORNIA AND WECC BID STRATEGY ASSESSMENT
(PERCENT OF SUPPLY)

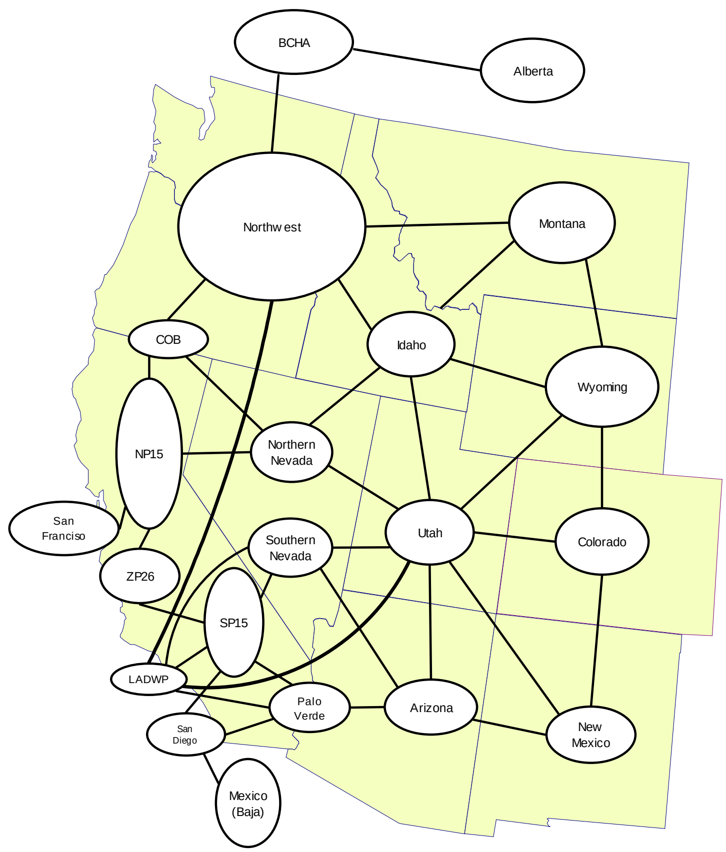
	Incremental	**Price Markup**	**Peak Period Bidding**	**Total**
California..................	68%	28%	4%	100%
Non-California..........	80%	14%	6%	100%
Total WECC.............	75%	20%	5%	100%

WECC REGIONAL MARKET DEFINITIONS

WECC electricity markets sometimes experience binding transmission constraints. Binding transmission constraints occur at times when transmission capacity on a specific linear path is fully utilized and no additional energy can be transported via that line or path. During such times, low-cost generators are forced to reduce output in favor of higher-cost units located within the constrained region.

To reflect transmission constraints encountered in WECC markets, the Department simulated 21 separate market regions, with transfer limitations between each region reflecting expected transmission system configurations. In selecting market regions, the Department examined WECC transmission system operations and also analyzed a number of transmission publications and studies prepared by the WECC.

Separate market-clearing prices were established within each regional market as shown in the figure. In establishing the market-clearing price for each region, the PROSYM simulation took into account economic import and export possibilities and set the market-clearing price as the bid price of the marginal generator needed to serve a final increment of demand within the region.



SIMULATION OF NEW RESOURCE ADDITIONS

To meet increases in peak demand, new resource additions must be included in the simulation. A review of potential and planned new resource additions throughout the WECC reveals that they will be built and owned primarily by independent power producers. Generally, the technology, fuel type, size, and location of these new plants will depend primarily upon wholesale power market prices. Prices available to an independent power producer must be sufficient to allow it to earn a return on equity that is consistent with similar risk capital investments.

To forecast the amount of capacity added in each region of the WECC, known potential new generating resources were reviewed to identify those currently under site certification or construction. These plants have a high probability of completion and were added to the simulation resource base in their expected year of completion. Capacity costs of the particular resource to be added are estimated based on publicly available cost information for the specific type of plant, and on certain financing term, interest rate, and return on equity assumptions.

The table below summarizes these assumptions for combustion turbine and combined cycle combustion turbine plants, which are expected to represent the major portion of all new generating resource additions in the WECC during the 2007 Revenue Requirement Period.

GENERIC RESOURCE ASSUMPTIONS

Unit Characteristic	Combustion Turbine	Combined Cycle
Heat Rate (Btu/kWh)	11,000	7,100
Fixed O&M ($/kW-year)	3.15	10.50
Variable O&M ($/MWh)	4.20	2.10
Forced Outage Rate (%)	0.00	2.00
Maintenance Outage Rate (%)	4.00	4.00
Financing Term (Years)	15	15
Interest Rate (%)	8.00	8.00
Return on Equity (%)[1]	18.00	18.00

Source: NCI. Cost figures represent 2002 dollars.
[1] After taxes.

To the extent the production simulation model determines that additional generating capacity, beyond that designated as planning capacity, is needed to meet the needs of the region, "generic" new generating units are assumed to be added to the resource mix.

LONG-TERM POWER CONTRACTS

The Department's contract resources were explicitly modeled in the simulation, accounting for their respective capacities, delivery points, minimum takes and other features. These contract resources are assumed to be called upon as a resource for meeting Customer needs and are expected to be dispatched in an economically efficient manner (from the Customers' perspective) as part of a complete resource mix that includes the utility retained generation, the Department's contracts, and residual net short purchases. Electronic copies of the Department's Long-Term Power Contracts are available at the Department's web site: http://www.cers.water.ca.gov.

CAISO LOCATIONAL MARGINAL PRICE AND CONGESTION REVENUE RIGHTS PROPOSALS

The California ISO has authorized its staff to develop detailed plans as part of its Market Redesign & Technology Upgrade ("MRTU") to create a structure that establishes locational marginal prices ("LMP") at many different nodes on the CAISO grid. In addition, the CAISO has adopted plans to create Congestion Revenue Rights ("CRR") which could have the effect of requiring the utilities to acquire CRRs to assure the delivery of energy from the Department's long-term energy supply contracts or else risk the possibility of failure to deliver, under certain transmission congestion situations, which would otherwise be economically delivered from the Department's contracts.

Under the MRTU CRR design, the deliverability of capacity and power into and across the California ISO controlled grid may be diminished even for schedules protected by Existing Transmission Contracts ("ETCs"). This is due to two primary elements: 1) the Available Transmission Capacity ("ATC") calculated for use in the CRR allocation process will not be based on the total contract capacity, but rather the "maximum coincident historical transmission capacity reservation on the respective contract path over the most recent 12-month period"; and 2) for ETCs converted to CRRs, the allocation is subject to Simultaneous Feasibility Tests ("SFT") in the allocation process, which may reduce the actual allocation compared to the ETC contract amount.

No such structure existed at the time the Department entered into the long-term contracts, and the Department is unaware of any published analysis by the CAISO or others as to what effect LMP and CRRs could have on the delivery of energy from the Department's contracts. To the extent that CRRs need to be purchased to assure delivery of energy under the Department's contracts, such costs, if incurred by the Department, would increase the Department's revenue requirement beyond the levels that would otherwise exist. To the extent that others purchase CRRs and such purchases ultimately preclude some portion of the Department's energy from being delivered, then the Department assumes that its average cost per MWH of energy will increase and the utilities will need to replace that energy which is not delivered due to this proposed market structure. The extent to which this structure could increase the Department's revenue requirements, as well as and the individual revenue requirements of the three utilities with respect to replacement energy they may need to acquire, is unknown at this time.

At present, the Department expects that the CAISO will implement the LMP and CRR provisions of MRTU during the fourth quarter of calendar year 2007. The Department intends to monitor the CAISO's process for evaluation and implementation of LMP and CRRs to assess and to quantify the possible effects of these structural changes within the energy market.

OTHER ASSUMPTIONS

A broad array of other inputs and assumptions were made in performing the WECC market simulation. These inputs and assumptions address resource availability, resource retirements, fuel prices, operation and maintenance costs, outage factors, transmission factors, and market conditions, among other factors, which are summarized in the table below.

Category	Assumption
Study Period	January 2007 through December 2007.
Load Forecast	From the EIA-411 filings of the WECC, except for IOU forecasts, which were developed as described elsewhere in this Determination.
Load Profiles	SCE and SDG&E load profiles were provided by the IOUs. The PG&E load shape was based on the composite hourly load profile for the 1993-1998 period contained in PROSYM, The PG&E load profiles were derived from hourly Edison Electric Institute load data files from the FERC web site.
Existing Resources	From the WECC EIA-411 filings.
Pacific Northwest Hydro	BPA 2000 Pacific Northwest Loads and Resources Study used to calculate monthly capacity and energy values for each hydroelectric station in the region, choosing median conditions from a recorded database of 50 years
California Hydro	WECC Coordinated Bulk Power Supply report for summer and winter capacity ratings for existing hydro resources.
Resource Retirements	No nuclear retirements at license expiration
Gas Prices	See "Natural Gas Price-Related Assumptions"
O&M Costs	Historical, power plant-specific, non-fuel operation and maintenance ("O&M") costs reported by utilities to FERC, averaged and normalized to develop average starting O&M costs. Amounts allocated between fixed and variable O&M costs. Both fixed and variable O&M costs are assumed to escalate with inflation.
Thermal Resource Models	• Multi-segment incremental heat rate curves. • Fixed and variable O&M costs. • Scheduled outages based on annual maintenance cycles. • Random forced outages based on unit-forced outage rates.
Contracts	• Known firm purchase/sales reported in the WECC Form OE-411 filing. • Transactions are reflected in the load requirements of the buying and selling utilities, in transactions between regions, and by adjusting the transmission capacity. • Transmission capacity between zones required for these transactions is assumed to have priority. Any remaining transmission capacity is used to facilitate additional power transactions between regions, based on economic dispatch and delivery over the remaining transmission capacity.
Thermal Resource Commitment and Dispatch	Unit commitment order determined by marginal operating cost (fuel and variable O&M costs). Commitment determined to satisfy load plus spinning reserve.
Transmission Model	Transmission system and constraints represented using transport model across regions.
Market Structure	Assumed open market across all the regions (region-wide dispatch). Energy interchange between regions occurs when spot price differentials exceed transmission tariff costs.

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

Volume	Record Number	Date	Record Title
DWR07pRR	001	10/27/05	Revised Determination of Revenue Requirements for 2006, including the Determination, the Notice, and the Transmittal letter to the Commission
DWR07pRR	002	10/27/05	Decision 05-10-042 “Opinion On Resource Adequacy Requirements”.
DWR07pRR	003	10/27/05	Decision 05-10 046 “Order Denying Rehearing of Decision 05-01-031”.
DWR07pRR	004	11/17/05	Official Statement for the new issue of $2,594,000,000 State of California Department of Water Resources Power Supply Revenue Bonds (Variable Rate Demand Bonds) consisting of $759,400,000 Series 2005F (Daily Rate) and $1,834,600,000 Series 2005G (Weekly Rate).
DWR07pRR	005	11/18/05	Decision 05-11-007 “Opinion On The Reasonableness And Prudence Of PG&E’s ERRA”.
DWR07pRR	006	12/01/05	Decision 05-12-010 “Opinion Allocating The 2006 Revenue Requirement Determination Of The CDWR and Denying Petition To Modify”.
DWR07pRR	007	12/12/05	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: PG&E updated 2006 DA CRS revenue estimate
DWR07pRR	008	12/14/05	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: SCE 2006 Energy Procurement Schedule and Alternatives
DWR07pRR	009	12/14/05	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: PG&E 2006 Energy Procurement Schedule
DWR07pRR	010	12/15/05	SDG&E Advice Letter 1758-E “Revisions To The DWR Power Charge And DWR Bond Charge Pursuant To D.05-12-010”.
DWR07pRR	011	12/15/05	SCE Advice Letter 1942-E “Implementation of the 2006 DWR Power and Bond Charges in Accordance with Decision 05-12-010”.
DWR07pRR	012	12/15/05	PG&E Advice Letter 2751-E “2006 DWR Revenue Requirement Determination”. This Advice Letter implements D. 05-12-010.
DWR07pRR	013	12/15/05	Decision 05-12-021 “ Opinion On Reallocation Of DWR Contracts”.
DWR07pRR	014	12/15/05	Decision 05-12-041 “Decision Resolving Phase 2 issues On Implementation Of Community Choice Aggregation Program And Related Matters”.
DWR07pRR	015	12/15/05	Decision 05-12-045 “Decision Adopting The 2006 Forecast Revenue Requirement For Pacific Gas And Electric Company’s Energy Resource Recovery Account And Competition Transition Charge”.

Volume	Record Number	Date	Record Title
DWR07pRR	016	12/30/05	PG&E Advice 2706-E-A: "Supplemental Filing – Annual Electric True-Up – Change PG&E Electric Rates on January 1, 2006."
DWR07pRR	017	01/01/06	CPUC "Community Choice Aggregation Report To The California Legislature".
DWR07pRR	018	01/12/06	Decision 06-01-007: " Opinion On The Reasonableness And Prudence Of Southern California Edison Company's (SCE's) Energy Resource Recovery Account (ERRA) & Other Balancing Accounts".
DWR07pRR	019	01/19/06	PG&E Advice 2767-E "Updated Schedules 1 and 3 of DWR Operating Agreement in Compliance with D.05-12-021 and Reflecting Current Changes".
DWR07pRR	020	01/26/06	Decision 06-01-035: "Opinion On Southern California Edison Company's 2006 Energy Resource Recovery Account Forecast
DWR07pRR	021	01/31/06	PG&E Advice 2775-E "PG&E's Electric Portfolio Gas Hedging Plan Update 2006-1, as Permitted by Resolution E-3951". *(Public Information as Filed).*
DWR07pRR	022	02/01/06	"Final Report of the Working Group to Calculate CRS Obligations Associated with Municipal Departing Load and Direct Access"
DWR07pRR	023	02/01/06	PG&E AL 2776-E "Submission of the Seventh Gas Supply Plan (GSP-7) for CDWR Tolling Agreements (April 1, 2006, through September 30, 2006)". (*Public Information as filed)*
DWR07pRR	024	02/01/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: PG&E Advice 2776-E: Gas Supply Plan 7 for CDWR Tolling Agreements.
DWR07pRR	025	02/01/06	SCE Advice 1961-E: "Submission of SCE's Seventh Gas Supply plan for the State of California DWR Tolling Agreements Pursuant to D. 03-04-029". *(Public Information as Filed)*
DWR07pRR	026	02/01/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: SCE Advice 1961-E: "Submission of SCE's Seventh Gas Supply plan for the State of California DWR Tolling Agreements Pursuant to D. 03-04-029".
DWR07pRR	027	02/01/06	SDG&E Advice 1768-E: "Submittal of SDG&E Gas Supply Plan for DWR Tolling Agreements Pursuant to Decision 03-04-029 and Resolution E-3854". *(Public Information as Filed).*
DWR07pRR	028	02/01/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: SDG&E Advice 1768-E: "Submittal of SDG&E Gas Supply Plan for DWR Tolling Agreements Pursuant to Decision 03-04-029 and Resolution E-3854".
DWR07pRR	029	02/23/06	"Administrative Law Judge's Ruling Incorporating Report and Letter Into The Record And Providing For Comments Thereon". (See document 022, Final Report of the Working Group…).

Volume	Record Number	Date	Record Title
DWR07pRR	030	02/03/06	SCE Advice 1962-E: "Implementation of February 4, 2006 Consolidated Revenue Requirement and Rate Change in Accordance with Decision No. 06-01-035."
DWR07pRR	031	02/10/06	SCE Advice 1964-E: "Modification to Schedule 1 of Operating Order Between CDWR and SCE in Accordance with Ordering Paragraph 7 of Decision 05-12-021".
DWR07pRR	032		Record number not utilized.
DWR07pRR	033		Record number not utilized.
DWR07pRR	034		Record number not utilized.
DWR07pRR	035	02/16/06	SCE Advice 1744-E-A Withdrawal: On October 4, 2004, SCE filed Advice 1744-E-A to clarify the implementation of the one-time bill credit ordered in D.03-09-018. The funds are to be submitted to the California State Controller's office through the normal escheatment process.
DWR07pRR	036	02/16/06	Decision 06-02-018: "Opinion On 2006 Energy Resource Recovery Account Forecast" for SDG&E.
DWR07pRR	037	02/16/06	Decision 06-02-031: "Opinion On Rehearing On SDG&E's Application For Approval For The Otay Mesa Generating Plant".
DWR07pRR	038	02/23/06	PG&E Advice 2790-E: "Planned Permanent Closure of PG&E's Hunters Point Power Plant". (The Commission approved the shutdown on March 15, 2006, in Resolution E-3984, [not included herein]).
DWR07pRR	039	02/23/06	DWR Memo to the CPUC re. SCE Advice 1962-E.
DWR07pRR	040	02/28/06	DWR Electric Power Fund Financial Statements for December 31, 2005.
DWR07pRR	041	03/01/06	SCE Advice 1975-E: "Temporary Suspension of Collection of Cost Responsibility Surcharge (CRS) from Community Aggregation (CA) Customers."
DWR07pRR	042	03/02/06	Decision 06-03-004: "Opinion Establishing Procedures To Seek Exemption Eligibility".
DWR07pRR	043	03/02/06	SCE Response to DWR Memo re. Advice 1962-E: SCE concurs with the facts stated in the DWR Memo.
DWR07pRR	044		Record number not utilized.
DWR07pRR	045	03/03/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: Record of Coordination: PG&E Question on Model.
DWR07pRR	046		Record number not utilized.
DWR07pRR	047		Record number not utilized.
DWR07pRR	048	03/22/06	DWR Data Request #1 to IOU's regarding the 2007 Revenue Requirements; Includes transmittal, Questions, DR1-Q1 Attachment, DR1-Q4 Attachment.
DWR07pRR	049	03/22/06	SDG&E Advice 1745-E-A: "Partial Supplemental Filing – Updated AB 57 Procurement Plan In Compliance With D.04-12-048". *(Public Information as Filed).*

Volume	Record Number	Date	Record Title
DWR07pRR	050	04/03/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: Record of Coordination: SCE questions related to DWR Data Request 1.
DWR07pRR	051	04/05/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: Record of Coordination: PG&E questions related to DWR Data Request 1.
DWR07pRR	052	04/11/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: Record of Coordination: SEMPRA questions related to CPA-DRP program.
DWR07pRR	053	04/13/06	Decision 06-04-020: "Opinion On The Reasonableness And Prudence Of San Diego Gas & Electric Company's Energy Resource Recovery Account".
DWR07pRR	054	04/13/06	Decision 06-04-040: "Order Modifying D.05-10-042 And Denying Rehearing Of Decision, As Modified".
DWR07pRR	055	04/19/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: SCE response to DWR Data Request number 1.
DWR07pRR	056	04/19/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: SDG&E response to DWR Data Request number 1.
DWR07pRR	057	04/19/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: PG&E response to DWR Data Request number 1.
DWR07pRR	058	04/27/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: Record of Coordination: NCI – PG&E e-mail string regarding NCI questions on PG&E data request response.
DWR07pRR	059		Record number not utilized.
DWR07pRR	060	05/11/06	Decision 06-05-007: "Opinion Granting Motion Of PG&E To Withdraw Motion For Authorization To Purchase And Deliver Gas As Needed For Electric And Gas System Reliability".
DWR07pRR	061	05/11/06	Decision 06-05-018: "Opinion Resolving Petition For Modification Of Decision 03-09-052". This order clarified the application of CRS obligations to new power preference customers of WAPA.
DWR07pRR	062	04/21/06	CDWR vs. Sempra Energy Resources: American Arbitration Association "Opinion And Award". The arbitration panel ruled Sempra Energy acted in bad faith and in breach of multiple aspects of its long-term energy contract with DWR, and awarded DWR more than $70 million in damages.
DWR07pRR	063	05/18/06	DWR Electric Power Fund Financial Statements for March 31, 2006.
DWR07pRR	064	01/03/06	DWR News Release announcing sale of unsecured settlement claim against Mirant. The news release announced the California parties have sold their unsecured claims against Mirant Americas Energy Marketing for $189.4 million.
DWR07pRR	065	05/25/06	Decision 06-05-039: "Opinion Conditionally Approving Procurement Plans For 2006 RPS Solicitations, Addressing TOD Benchmarking Methodology, And Closing Proceeding".

Volume	Record Number	Date	Record Title
DWR07pRR	066	06/01/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: Transmittal of PG&E PROSYM data to PG&E and the CPUC Staff for review and comment.
DWR07pRR	067	06/01/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: Transmittal of SCE PROSYM data to SCE and the CPUC Staff for review and comment.
DWR07pRR	068	06/01/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: Transmittal of SDG&E PROSYM data to SDG&E and the CPUC Staff for review and comment.
DWR07pRR	069	06/06/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: PG&E Response Comments on PROSYM 57 Data
DWR07pRR	070	06/07/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: SCE Response Comments on PROSYM 57 Data
DWR07pRR	071	01/27/06	United States District Court Southern District Of New York: Order in CDWR, et al., Plaintiffs, against Calpine Corporation, et al., Defendants (as amended on February 2, 2006 to correct a typographical error. This Order related to FERC jurisdiction over energy contracts.
DWR07pRR	072	01/30/06	Calpine Notice Of Appeal of the United States District Court Southern District Of New York order.
DWR07pRR	073	03/09/06	Brief of CDWR et al., In The United States Court Of Appeals For The Second Circuit in Re: Calpine Corporation.
DWR07pRR	074	05/11/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: IOU Gas Hedging Analysis
DWR07pRR	075	10/21/05	SDG&E Advice Letter 1726-E-A: “Supplemental Filing – Reduction To The Direct Access Cost Responsibility Surcharge (DA CRS) Amount”.
DWR07pRR	076	04/10/06	CERS Comments on MRTU in FERC ER06-615
DWR07pRR	077	04/10/06	CERS SEMPRA Joint Comments on MRTU in FERC ER06-615
DWR07pRR	078	05/16/06	CERS SEMPRA Joint Reply Comments on MRTU in FERC ER06-615
DWR07pRR	079	06/14/06	IOU Monthly Reports To The CPUC Regarding Direct Access Load And Service Request Changes. This information may be found on the CPUC Web Site under “Direct Access Implementation Activity Reports”.
DWR07pRR	080	06/15/06	Memorandum to Jim Olson on gas price forecasting methodology.
DWR07pRR	081	06/19/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: PROSYM Run 57 – projections of loads and resources for each IOU
DWR07pRR	082	06/19/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: Financial Model CFMG5V2 – projections of Bond and Power Revenue Requirements
DWR07pRR	083	06/19/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: Gas Hedging Work paper – DWR hedging amount and expense for 2007

Volume	Record Number	Date	Record Title
DWR07pRR	084	06/15/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: 2007 IOU Hedging Estimates
DWR07pRR	085	06/20/06	ALJ Pulsifer Draft: “Opinion Regarding Direct Access And Departing Load Cost Responsibility Surcharge Obligations”.
DWR07pRR	086	06/20/06	ALJ Wetzell Draft: “Opinion On Remaining Phase 1 Issues”: proposals for refinements to and clarification of the Commission’s resource adequacy requirements (RAR) program.
DWR07pRR	087	06/20/06	ALJ Brown Draft: “Opinion On New Generation And Long-Term Contract Proposals And Cost Allocation”.
DWR07pRR	088	06/20/06	CONFIDENTIAL, NOT FOR PUBLIC RELEASE: Natural Gas Forecast Comparisons.
DWR07pRR	089	06/21/06	DWR Letter to the CPUC Regarding SCE AL 1962-E.
DWR07pRR	090	06/22/06	Memorandum to Jim Olson on the EEA Natural Gas Model.