State of California

Department of Water Resources

Proposed

Determination of Revenue Requirements

For the Period

January 1, 2005, Through December 31, 2005

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

September 09, 2004

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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, 2005, through December 31, 2005 (the "2005 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 the net short requirements of the IOUs using a combination of long-term power contracts, short-term power contracts and wholesale energy purchases through the end of 2002. 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."

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 energy not provided under the Department's long-term contracts is 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. A copy of the full text of AB 57 is included in the administrative record supporting this Proposed Determination.

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 contemplated 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 2005 Revenue Requirement period (calendar year 2005).

[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.

A reconciliation of the Department's costs and revenues relative to revenue requirements through December 31, 2004 will be provided separately when actual data is available. Any "true-up" with respect to Department revenue requirements, if required (as opposed to any true-up of the allocation of those requirements), will occur as new revenue requirements are determined. For example, this 2005 Proposed Determination takes into account preliminary actual results of Department operations through June 30, 2004 and revised projections of results of operations through the end of 2004.

For the 2005 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.

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 2005 Proposed Determination (including the materials referred to in Section H), that its cash basis revenue requirement for 2005 is $4.811 billion, consisting of $3.925 billion in Department Costs and $0.886 billion in Bond Related Costs.

Table A-1 shows a summary of the Department's revenue requirements and accounts associated with projected Department Costs ("Power Charge Accounts") for 2005. These figures are compared to those reflected in the Department's Supplemental Determination of Revenue Requirements for the period January 1, 2004 through December 31, 2004, published April 16, 2004 (the "2004 Supplemental Determination").

A summary and comparison of the Department's revenue requirements and 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.

TABLE A-1
SUMMARY OF THE DEPARTMENT'S 2005 POWER CHARGE REVENUE REQUIREMENTS AND POWER CHARGE ACCOUNTS AND COMPARISON TO 2004[1]
($ Millions)

Line	Description	2005[2]	2004[3]	Difference
1	*Beginning Balance in Power Charge Accounts*			
2	Operating Account	1,029	1,031	1
3	Priority Contract Account	-	-	-
4	Operating Reserve Account	595	630	35
5	**Total Beginning Balance in Power Charge Accounts**	**1,624**	**1,660**	**36**
6	*Power Charge Accounts Operating Revenues*			
7	Power Charge Revenues from Bundled Customers[4]	3,925	4,272	347
8	Extraordinary Receipts[5]	45	52	7
9	Other Revenue[6]	202	273	71
10	Interest Earnings on Fund Balances	25	32	7
11	**Total Power Charge Accounts Operating Revenues**	**4,198**	**4,628**	**430**
12	*Power Charge Accounts Operating Expenses*			
13	Administrative and General Expenses	45	59	14
14	Total Power Costs	4,419	4,860	441
15	Gas Collateral Costs	70	37	(33)
16	**Total Power Charge Accounts Operating Expenses**	**4,534**	**4,956**	**422**
17	Net Operating Revenues	(336)	(327)	9
18	Net Transfers from/(to) Bond Charge Accounts & Adjustments	-	7	7
19	Total Net Revenues	(336)	(321)	15
20	**Ending Aggregate Balance in Power Charge Accounts**	**1,288**	**1,340**	**51**

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.	317	296	(21)
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.	544	595	51
Total Operating Reserves:	861	891	30

[1]Numbers may not add due to rounding.
[2]As proposed herein.
[3]As reflected in the 2004 Supplemental Determination.
[4]CRS Power Charge Revenues are included in this amount, 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 2005 BOND CHARGE REVENUE REQUIREMENTS AND BOND CHARGE ACCOUNTS AND COMPARISON TO 2004[1]
($ Millions)

Line	Description	2005[2]	2004[3]	Difference
1	*Beginning Balance in Bond Charge Accounts*			
2	Bond Charge Collection Account	107	129	22
3	Bond Charge Payment Account	666	429	(237)
4	Debt Service Reserve Account	927	927	-
5	**Total Beginning Balance in Bond Charge Accounts**	**1,700**	**1,485**	**(215)**
6	*Bond Charge Accounts Revenues*			
7	Bond Charge Revenues from Utiltities[4]	886	891	5
8	Interest Earnings on Fund Balances	47	26	(21)
9	**Total Bond Charge Accounts Revenues**	**933**	**918**	**(15)**
10	*Bond Charge Accounts Expenses*			
11	Debt Service on Bonds	922	725	(196)
12	Other Bond Charge Account Expenses	-	-	-
13	**Total Bond Charge Accounts Expenses**	**922**	**725**	**(196)**
14	Net Bond Charge Revenues	11	192	181
15	Net Transfers from/(to) Power Charge Accounts & Adjustment	-	-	-
16	Total Net Revenues	11	192	181
17	**Ending Aggregate Balance in Bond Charge Accounts**	**1,711**	**1,677**	**(34)**

Target Minimum Bond Charge Account Balances	Target (Millions of Dollars)		
Bond Charge Collection Account: An amount equal to one month's required deposit to the Bond Charge Payment Account for projected debt service	76 - 78	75 - 78	
Bond Charge Payment Account: An amount equal to the debt service accrued and unpaid through the end of the third next succeeding calendar month	335 - 932	300 - 702	
Debt Service Reserve Account: Established as the maximum annual debt service	927	927	

[1]Numbers may not add due to rounding.
[2]As proposed herein.
[3]As reflected in the 2004 Supplemental Determination.
[4]CRS Power Charge Revenues are included in this amount, whether from Direct Access or other sources, such as Community Choice Aggregation.

FUTURE ADJUSTMENT OF REVENUE REQUIREMENTS

The Department may revise its revenue requirements for the 2005 Revenue Requirement period given the potential for significant or material changes in the California energy market, the status of market participants, 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. 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 Rate Agreement requires the Commission to impose Bond Charges that are sufficient, together with amounts on deposit in the Bond Charge Collection Account, to pay all Bond Related Costs, as well as meet all Bond covenants as they come due.

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 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 of the imposition and collection of these charges, the Department's Retail Revenue Requirement (Power Charges to be collected from bundled customers) is lower. This 2005 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.

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[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.

Revenues from Power Charges are deposited into an "Operating Account." Funds in the Operating Account are used to pay Department Costs 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 2004 AND THE PROJECTED STARTING BALANCE FOR 2005

On July 18, 2003, the Department published its Proposed Determination of Revenue Requirements for 2004, 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.

On August 14, 2003, the Department received comments on the 2004 Proposed Determination from PG&E, SCE, and SDG&E. After a review of all comments and an analysis of Decision 03-09-018 (Order Implementing Allocation of the Supplemental 2003 Revenue Requirement Determination of the California Department of Water Resources, dated September 4, 2003), the Department made changes in the 2004 Proposed Determination, resulting in the Determination of Revenue Requirements for the period January 1, 2004 through December 31, 2004, which was published on September 18, 2003 and submitted to the Commission.

Thereafter, the Commission commenced hearings on the allocation of the 2004 revenue requirements among retail customers in the service territories of the IOUs. On January 8, 2004, in Decision 04-01-028, the Commission adopted an interim allocation of the Department's 2004 revenue requirements.

In addition, hearings were initiated to address a permanent methodology for allocating DWR's revenue requirements for 2004 and future years. Concurrent with the adoption of the interim allocation, new information became apparent that could potentially change the Department's revenue requirements for 2004. As a result, on March 10, 2004 the Department published its Proposed Supplemental Determination of Revenue Requirements for the period January 1, 2004 through December 31, 2004, reflecting a proposed reduction of $194 million to its 2004 revenue requirements.

Between March 10, 2004 and April 1, 2004, the Department received comments on the Proposed Supplemental Determination from PG&E, SCE, and SDG&E. After a review of all comments, the Department made changes to the 2004 Proposed Supplemental Determination, resulting in the Supplemental Determination of Revenue Requirements for the period January 1, 2004 through December 31, 2004, which was published on April 16, 2004 and submitted to the Commission. The Department determined, on the basis of the materials presented and referred to by the 2004 Supplemental Determination, its Power Charge Revenue Requirement for the period of January 1, 2004 through December 31, 2004 to be $4.272 billion, a decrease of $245 million from the 2004 Determination, primarily resulting from a higher-than-projected aggregate ending balance in the Department's Power Charge Accounts as of December 31, 2003. Additional detail related to the 2004 Supplemental Determination of Revenue Requirements is provided in the 2004 Supplemental Determination itself, which is included as part of the administrative record supporting this 2005 Proposed Determination.

On August 19, 2004, the CPUC adopted Decision 04-08-050, implementing the 2004 Supplemental Determination consistent with the interim allocation methodology adopted in Decision 04-01-028. This 2005 Proposed Determination is based in part on the Commission's implementation of the 2004 Supplemental Determinations, resulting in a starting balance for the 2005 Revenue Requirement period as projected herein.

Upon completion of the procedures set forth in the Regulations, the Department will determine its revenue requirements for the 2005 Revenue Requirement period.

C. THE DEPARTMENT'S PROPOSED DETERMINATION OF REVENUE REQUIREMENTS FOR THE PERIOD JANUARY 1, 2005 THROUGH DECEMBER 31, 2005

REVENUE REQUIREMENT DETERMINATION

For 2005, 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 costs, and

(4) Amounts required to maintain operating reserves as determined by the Department (see Table A-1).

Power Charge Accounts 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 Direct Access Power Charge Revenues, as those terms are defined in the Bond Indenture).

There are no provisions included in Department Costs for the procurement of the residual net short by the Department during 2005.

During 2005, the Department projects that it will incur the following Department Costs: (a) $4.419 billion for long-term power contract purchases to cover the net short requirement of customers; (b) $45 million in administrative and general expenses; (c) $70 million in gas collateral costs; and (d) $(336) million in other net changes to Power Charge Accounts (including operating reserves). This projection results in a total revenue need of $4.198 billion.

Funds to meet these costs (in addition to surplus operating reserves) are projected to be provided from (a) $202 million from the Department's share of surplus power sales revenues; (b) $25 million of interest earned on Power Charge Account balances; (c) $45 million of extraordinary receipts resulting from the ongoing benefits of the El Paso and Williams contract settlements; and (d) $3.925 billion from Power Charge Revenues and Direct Access Power Charge Revenues.

Table C-1 provides a quarterly projection of costs and revenues associated with the Power Charge Accounts for the 2005 Revenue Requirement period.

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

Line	Description	Amounts for 2005 Revenue Requirement Period (Millions of Dollars)				
		2005 - Q1	2005 - Q2	2005 - Q3	2005 - Q4	Total
1	*Power Charge Accounts Expenses*					
2	Power Costs	1,087	873	1,309	1,151	4,419
3	Administrative and General Expenses	11	11	11	11	45
4	Gas Collateral Costs	-	7	33	29	70
7	Net Changes to Power Charge Account Balances	(7)	(14)	(240)	(75)	(336)
8	**Total Power Charge Accounts Expenses**	**1,091**	**877**	**1,113**	**1,117**	**4,198**
9	*Power Charge Accounts Revenues*					
10	Extraordinary Receipts	6	-	40	-	45
11	Other Power Sales Revenues	75	37	41	49	202
12	Interest Earnings on Power Charge Account Balances	9	-	17	-	25
13	Total Power Charge Revenue Requirement[1]	1,002	840	1,015	1,068	3,925
14	**Total Power Charge Accounts Revenues**	**1,091**	**877**	**1,113**	**1,117**	**4,198**

[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 2005 Revenue Requirement period.

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

Line	Description	Amounts for 2005 Revenue Requirement Period (Millions of Dollars)				
		2005 - Q1	2005 - Q2	2005 - Q3	2005 - Q4	Total
1	*Bond Charge Accounts Expenses*					
2	Debt Service Payments	35	623	36	227	922
3	Net Changes to Bond Charge Account Balances	181	(402)	213	19	11
4	**Total Bond Charge Accounts Expenses**	**216**	**222**	**249**	**246**	**933**
5	*Bond Charge Accounts Revenues*					
6	Interest Earnings on Bond Charge Account Balances	5	16	11	16	47
7	Retail Customer Bond Charge Revenue Requirement	211	206	239	230	886
8	**Total Bond Charge Accounts Revenues**	**216**	**222**	**249**	**246**	**933**

During 2005, the Department projects that it will incur the following Bond Related Costs: (a) $922 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) $11 million for changes to Bond Charge Account balances, resulting in total Bond Charge Account expenses of $933 million.

Funds to meet these requirements are provided from (a) $47 million in interest earned on Bond Charge Account balances, and (b) $886 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 $5.456 billion. Revenues from interest earned and other power sales are $320 million, and net changes in fund balances are $(325) million, resulting in combined customer revenue requirements of $4.811 billion.

D. ASSUMPTIONS GOVERNING THE DEPARTMENT'S PROJECTION OF REVENUE REQUIREMENTS FOR THE 2005 REVENUE REQUIREMENT PERIOD

This 2005 Proposed Determination is based on a number of assumptions regarding sales, power supply, natural gas prices, off-system sales, demand side management and conservation, and administrative and general expenses.

LOAD AND SALES FORECAST

The Department obtained the most recent forecasts of customer loads from PG&E and SDG&E in January 2004 and from SCE in April 2004. The forecasts received from the IOUs were compared with other relevant information including recorded IOU sales data, utility expected growth factors, and forecasts prepared by the California Energy Commission ("CEC"). A loss factor was applied to the IOU estimates of sales at customer meters to obtain the total amount of necessary energy to meet customer electricity requirements. The loss factors utilized in developing the estimate of the electricity requirements are presented in Table D-1.

TABLE D-1
LOSS FACTORS UTILIZED

Utility	Distribution	Transmission	Total
PG&E	6.4%	2.0%	8.4%
SCE	5.2%	3.3%	8.5%
SDG&E	4.6%	1.8%	6.4%

Each IOU forecast was developed using econometric models. The models rely on a statistical analysis of historical data to develop regression equations that relate changes in "independent" variables (such as employment growth) to "dependent" variables (such as electricity sales by the end-user segment). The resulting equations, together with forecasts of electricity prices, weather conditions, and key economic drivers, are used to predict sales by revenue class. To improve accuracy, the projections may be modified to account for current trends, judgment, or other events not specifically addressed in the models.

Table D-2 presents the major assumptions employed in the IOU forecasts utilized by the Department for the purpose of this 2005 Proposed Determination. The economic forecast for PG&E was based on a forecast of economic growth in PG&E's service area prepared by Economy.com. SCE derived its economic assumptions from a national and statewide forecast prepared by Data Resources Inc. ("DRI"), and SDG&E relied on a DRI forecast of economic trends in its service area.

TABLE D-2
MAJOR ASSUMPTIONS USED IN THE LOAD FORECASTS OF THE INVESTOR-OWNED UTILITIES

	PG&E	SCE	SDG&E
Growth Assumptions:			
Population Growth	1.1%	1.1%	1.5%
Number of Households	1.4%	1.5%	1.8%
Non-Farm Employment	0.6%	0.9%	2.0%
Heating Degree Days	20-Yr. Avg.	30-Yr. Avg.	20-Yr. Avg.
Cooling Degree Days	20-Yr. Avg.	30-Yr. Avg.	20-Yr. Avg.

Source: Assumptions provided by forecasting group of each IOU between March and June of 2004. Figures are for 2005 for SCE and SDG&E and 2004 for PG&E.

SOURCES OF IOU FORECASTS

The Department obtained load forecasts from each IOU. For PG&E, the Department relied on PG&E Advice Letter 2464-E, filed January 21, 2004, describing tariff changes required for its modified short-term procurement plan. For SCE, the Department relied on an April 2004 forecast that DWR is informed will be used in the utility's 2006 General Rate Case. For SDG&E, the Department relied on SDG&E's Advice Letter 1557-E, filed January 20, 2004, describing revisions to its short-term procurement plan. These projections include transmission and distribution losses (i.e. at the generator).

HOURLY LOAD SHAPES

The Department utilized total retail and Direct Access hourly load shapes provided by each of the IOUs in 2002. Hourly energy and peak usage was estimated by applying percentage of sales in each hour to annual energy estimates provided by the IOUs.

SELF-GENERATION

To determine the outlook for self-generation, the Department prepared a forecast of the potential increase in self-generating capacity in the IOU service areas. The forecast considered a range of factors including: (a) self-generation and/or renewable resource incentive programs and initiatives administered by the CEC, the Commission, the California Consumer Power and Conservation Financing Authority ("CPA"), and the California Independent System Operator ("CAISO"); (b) recent price increases, cost responsibility surcharges, the suspension of Direct Access, increased concerns over service reliability, and ongoing efforts to standardize interconnection requirements through the Commission's Rule 21 proceedings; and (c) potential barriers and market restraints to the expansion of self-generation. The forecasted self-generation is incorporated in the IOU forecasts. Therefore, the estimate of self-generation does not result in a net reduction in energy and demand requirements compared with the forecasts prepared by the IOUs. Trends in self-generation capacity will be monitored and these assumptions will be revisited if warranted.

DIRECT ACCESS

In Decision 02-03-055, the Commission implemented the suspension of direct access, which foreclosed the right of bundled load to elect direct access service after September 20, 2001. Electric end-users who elected to acquire electricity supplies from alternative providers on or before September 20, 2001 and have not since returned to bundled service continue to be eligible for direct access service. Decision 02-03-055 prohibits the IOUs from accepting any new direct access service requests not already approved by the Commission, including requests from existing qualified direct access end-users that wish to add new direct access locations or accounts to their service[45], and contemplates the establishment of a surcharge on direct access customers. The direct access surcharge is intended to prevent cost shifting as a result of direct access migration prior to September 20, 2001[6].

On February 19, 2004, the Commission issued Decision 04-02-042 which allows current direct access customers to increase load at one or more locations provided that net load by the same customer does not increase within a utility's service territory. This provision is intended to maintain the "standstill principle" adopted in 02-03-055, while accounting for "normal changes in business operations[7]." In Decision 04-07-025, the Commission clarified rules governing load growth for existing direct access accounts.

The Department's direct access estimates, which are based on data provided by the utilities in January 2004, are included in Table D-3. Based on the conditions imposed by applicable CPUC Decisions, the Department believes that direct access will continue at or near such levels in 2005. The Department regularly reviews each utility's monthly report to the Commission on current direct access load and service request changes, for any changes that would require action by the Department.

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[4]Under Decision 04-02-042, issued in February 2004, the Commission will allow existing direct access load to add new load at a new location or on a new account so long as its net load in a given service territory does not increase.

[5] However, direct access customers may renew their direct access service contracts upon their expiration or transfer such contract to a new service location provided the new and old loads served are of comparable size.

[6] See discussion under Direct Access Surcharge Revenues, below.

[7] Decision 04-02-042, Finding of Fact 4.

TABLE D-3
DIRECT ACCESS PERCENT OF LOAD[8]

	Percentage of Total Load
Pacific Gas and Electric Company	10.6%
Southern California Edison Company	13.6%
San Diego Gas and Electric Company	16.5%
Statewide	**12.6%**

OTHER DEPARTING LOAD

Other departing load includes customer self-generation, relocation of load or annexation of load to a municipality ("municipal departing load" or "MDL"), and Community Choice Aggregation ("CCA"). Self generation describes load that supplies all or a portion of its energy requirements from on-site or "over-the-fence" generation. Municipal departing load refers to load that either relocates to a California municipality or resides on land that is annexed by a municipality. 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[9]."

In 2005, the Department expects the total load from self generation, MDL, and CCA to amount to less than 1% of total retail sales. Unlike direct access, the growth of self generation, MDL, and CCA is not expressly limited by Commission decision. However, the Commission has imposed, or has expressed its intention to impose, on certain classes of self generation, MDL, and CCA customers a surcharge or other mechanism to prevent cost shifting similar to the cost responsibility surcharge imposed on direct access load. Therefore, the Department anticipates that in the future it may collect a portion of its revenue requirement from self generation, MDL, and CCA customers.

In 2005 and beyond, the amount of departing load could increase significantly. While the permitting process and the relatively high capital costs of installing micro-turbines or other on-site generation will curb the growth of self generation, and MDL is expected to follow historical growth trends, the opportunity for whole communities to aggregate load and procure power at competitive prices under CCA could lead to substantial reductions in bundled sales volumes in the coming years. The Department is closely monitoring Rulemaking 03-10-003, establishing processes, procedures, and surcharges for CCA loads. Based on the requirements of AB117 and the progress of Rulemaking 03-10-003, the Department does not expect CCA load to rise to substantial levels before 2006. DWR does not anticipate receiving any revenues from CCA customers during 2005.

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[8] Figures in Table D-3 represent direct access as a percentage of total retail load for 2005. These percentages correspond to direct access loads forecast by the IOUs in 2004. The Department assumes that direct access load will remain constant from 2004 to 2005.

[9] Public Utilities Code, Section 331.1(a).

Cost Responsibility Surcharge

In a series of decisions, the Commission has ordered certain classes of direct access and other departing load customers to pay a Cost Responsibility Surcharge ("CRS") related to historical stranded costs and ongoing costs. The CRS generally comprises four components:

- DWR Bond Charge: charge for debt service associated with the Department's 2002 issuance of revenue bonds.
- DWR Power Charge: charge related to DWR contract costs incurred by bundled load on an ongoing basis.
- Historical Procurement Charge ("HPC"): charge to recover SCE's historical under collection of costs in 2000 and PG&E's Regulatory Asset established in its bankruptcy settlement with the Commission. The Department anticipates that the Commission will adopt a dedicated rate component pursuant to Senate Bill 772 to replace PG&E's Regulatory Asset charge.
- Tail Competition Transition Charge ("CTC"): charge related to uneconomic URG, QF, and purchased power agreement costs incurred by bundled customers on an ongoing basis.

Payments by direct access and other departing load of the DWR Bond Charge and the DWR Power Charge flow to the Department through Commission established rates on total usage by departed customers. These revenues reduce one-for-one the bundled customer responsibility for the DWR Bond Charge and DWR Power Charge. DWR Power Charge collections from direct access, self generation, and MDL customers, in particular, are limited by a maximum collections rate, or cap, established by the applicable Commission Decisions. Differences in the collection and accrual rate for the DWR power charge component of the CRS are carried forward to collect in future periods when the current period collections rate is less than the current period accrual rate.

The CRS does not affect Department power costs. The CRS creates a revenue offset to bundled customers for a portion of the costs associated with the bundled customer portfolio. With the exception of minor differences in the timing of revenue receipt between bundled customers and non-exempt direct access and other departing load customers, the revenue requirement in total is unaffected by the amount of the CRS.

PG&E Sales to Western Area Power Administration ("WAPA")

Contract 2948A, signed in 1967, governs the interconnection of PG&E's and WAPA's transmission and distribution systems and the integration of their loads and resources. The contract allows WAPA to integrate PG&E's fossil-fueled and other generating resources with the hydropower resources of the federal Central Valley Project ("CVP") and deliver this "firmed" energy to preference power customers—generally government and municipal entities—pursuant to Federal reclamation law. In return, PG&E receives access to surplus CVP hydroelectric generation, which is less expensive than other resources available to

PG&E. Virtually all of WAPA's 73 preference power customers are located in the PG&E service region in northern California.

Contract 2948A expires at the end of 2004. For purposes of this 2005 Proposed Determination, the Department has assumed that this contract will not be renewed or replaced with another, similar contract.

PEAK LOAD AND ENERGY CALCULATIONS

Table D-4 provides the peak megawatt demand forecast for each IOU in 2005. Based on their respective load shapes, the total peak demand for PG&E, SCE, and SDG&E occur in August 2005. The total IOU peak demand is the sum of the individual peaks. Due to load diversity, the coincident peak computed in PROSYM (a market simulation tool supporting this 2005 Proposed Determination) is likely to be higher than that experienced under actual conditions.

TABLE D-4
ESTIMATED PEAK DEMAND[10]

	Amounts for the Revenue Requirement Period (Megawatts)
Pacific Gas and Electric Company	
Peak Demand	18,302
Less Direct Access	1,246
Peak Demand After Adjustments[11]	17,056
Southern California Edison Company	
Peak Demand	19,440
Less Direct Access	2,260
Peak Demand After Adjustments	17,180
San Diego Gas and Electric Company	
Peak Demand	4,105
Less Direct Access	478
Peak Demand After Adjustments	3,627
All Investor-Owned Utilities	
Peak Demand	41,847
Less Direct Access	3,984
Peak Demand After Adjustments[12]	37,863

[10] All values presented in Table D-4 include transmission and distribution losses (i.e. "at the generator").
[11] For all three IOUs, these amounts are intended to represent peak demands that must be met by electric generating resources or power purchases or a combination of the two.
[12] Represents the sum of the individual IOU amounts. The actual value at the time of the system's coincident peak may be lower.

Table D-5 shows the estimated gigawatt hours of energy requirements expected during 2005.

TABLE D-5
ESTIMATED ENERGY REQUIREMENTS[13]

	Amounts for the Revenue Requirement Period (Gigawatt-Hours)
Pacific Gas and Electric Company	
Energy Requirements	89,323
Less Direct Access	9,504
Energy Requirements After Adjustments[14]	79,819
Southern California Edison Company	
Energy Requirements	90,824
Less Direct Access	12,366
Energy Requirements After Adjustments	78,458
San Diego Gas and Electric Company	
Energy Requirements	20,908
Less Direct Access	3,447
Energy Requirements After Adjustments	17,461
All Investor Owned Utilities	
Energy Requirements	201,055
Less Direct Access	25,317
Energy Requirements After Adjustments	175,738

POWER SUPPLY RELATED ASSUMPTIONS

Two types of power supplies needed to meet the requirements of the three IOUs were considered by the Department in this 2005 Proposed Determination: (a) Supply from Priority Long-Term Power Contracts and (b) the residual net short of the three IOUs.[15]

[13] All values presented in Table D-5 include transmission and distribution losses.
[14] For all three IOUs, these amounts are intended to represent energy requirements that must be met by electric generating resources or power purchases or a combination of the two.
[15] While the Department has calculated and presented the residual net short requirements of the IOUs, pursuant to AB1X, the Department has not made any provision for the cost of the residual net short requirements in its Proposed Determination for the 2005 Revenue Requirement period.

Table D-6 below shows, for the 2005 Revenue Requirement period, the combined estimated peak demand for the three IOUs, the estimated peak demand after adjustments, estimated supplies from generation retained by the three IOUs,[16] the resulting net short, the expected supply from the Department's Priority Long-Term Power Contracts, and the residual net short.

TABLE D-6
ESTIMATED NET SHORT PEAK DEMAND, CAPACITY FROM PRIORITY LONG-TERM POWER CONTRACTS AND THE DEPARTMENT'S ESTIMATE OF THE RESIDUAL NET SHORT CAPACITY

	Amounts for the Revenue Requirement Period (Megawatts)
All Investor Owned Utilities	
Peak Demand[17]	41,847
Peak Demand After Adjustments	37,863
Less, Supply from Utility Resources	23,208
Net Short	14,655
Less, Supply from the Department's Priority Long Term Power Contracts	10,847
Residual Net Short (Surplus)	3,808

[16] For purposes of this 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.
[17] See the discussion under "Load and Sales Forecast Assumptions" for an explanation of the source of data on peak demand for each of the three IOUs.

Table D-7 below presents similar combined information for the three IOUs in terms of energy requirements during the 2005 Revenue Requirement period.

TABLE D-7
ESTIMATED NET SHORT ENERGY, SUPPLY FROM PRIORITY 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	175,805
Supply from Utility Resources	124,495
Net Short	51,311
Supply from the Department's Priority Long Term Power Contracts	56,080
Off-System Sales	(13,283)
Residual Net Short (Surplus)	8,513

For informational purposes, Table D-8 shows, for the 2005 Revenue Requirement period, the expected average cost (in $/MWh) on a quarterly basis for the Department's Priority Long Term Power Contracts.

TABLE D-8
ESTIMATED POWER SUPPLY COSTS
(Dollars per Megawatt-Hour)

	Long-Term Priority Contracts
Quarter 1 – 2005	73
Quarter 2 – 2005	79
Quarter 3 – 2005	85
Quarter 4 – 2005	74

Table D-9 shows, on a quarterly basis for the 2005 Revenue Requirement period, estimated net short volumes in gigawatt-hours, supply from Priority Long-Term Power Contracts, and the residual net short.

TABLE D-9
NET SHORT, SUPPLY FROM PRIORITY LONG-TERM POWER CONTRACTS, OFF-SYSTEM SALES AND RESIDUAL NET SHORT IN 2005

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)
Q1-2005	10,685	13,420	983	(3,654)	(164)	918
Q2-2005	10,327	12,515	991	(3,548)	(120)	1,360
Q3-2005	16,274	15,754	1,335	(2,707)	(130)	3,226
Q4-2005	14,026	14,391	1,062	(3,374)	(170)	3,009
Total	51,311	56,080	4,371	(13,283)	(585)	8,513

NATURAL GAS PRICE FORECAST AND FUELS ASSUMPTIONS

The natural gas price forecast supporting this 2005 Proposed Determination is an update to the 2004 gas price forecast. The update was prepared by DWR and its advisors in August 2004. This forecast reflects an increase to the 2005 price forecast when compared to the January 2004 price forecast supporting the 2004 Supplemental Determination. The forecast updates several key variables including the Henry Hub base forecast, an update to actual wellhead gas prices through August 2004, an update to the model's well completion variable and a change to express prices in 2004 dollars (in place of 2002 dollars, which was used in the 2004 forecast supporting the 2004 Supplemental Determination). In addition, NYMEX futures prices at Henry Hub are used to forecast monthly prices through 2005.

A comparison of the year-over-year Henry Hub prices forecast in the 2004 Supplemental Determination and the update used in this 2005 Proposed Determination is shown in Table D-10.

TABLE D-10
2004 NATURAL GAS PRICE FORECAST COMPARISON
(Nominal $/MMBtu)

	2004	2005	2006
2004 Gas Price Forecast August Update	$5.92	$6.29	$5.70
2004 Gas Price Forecast	$5.23	$5.23	$5.21
Difference	$0.69	$1.06	$0.49

As explained in the 2004 Supplemental Determination, the gas price forecast and associated updates are prepared by using a proprietary econometric Long-Term Price Model, the same model used in all prior revenue requirement determinations. The annual Henry Hub forecast was updated in January 2004 with new demand data from the U.S. Energy Information Administration (EIA), lagged actual historical prices, and new data gathered updating the weather-adjusted storage variable (the January base model was subsequently modified in April 2004 to reflect a modeling correction to the Rockies basis calculation, which affected several non-California pricing points). For the 2005 forecast the lagged actual historical price variable includes actual historical prices through August 2004 and NYMEX futures prices through 2005. The futures prices used in updating the lagged historical price variable were an average of 10 days closing settlement prices for Henry Hub prior to and including August 25, 2004. Once the base forecast price was determined at Henry Hub, specific delivery point prices were projected using price regression analysis to the various respective delivery point locations utilized by the model Monthly prices were then determined by using historical "spread factors". Table D-11 illustrates the updated price forecast at two key pricing hub locations: PG&E City-gate and Southern California Border.

TABLE D-11
NATURAL GAS AVERAGE PRICE FORECASTS
(Nominal $/MMBtu)

	Southern California Border		**PG&E Citygate**	
	2005	**2006**	**2005**	**2006**
January	$6.39	$5.86	$6.59	$6.04
February	$5.46	$5.00	$5.63	$5.16
March	$5.27	$4.83	$5.43	$4.98
April	$5.56	$5.10	$5.74	$5.26
May	$5.89	$5.39	$6.07	$5.57
June	$5.95	$5.45	$6.13	$5.63
July	$5.81	$5.33	$6.00	$5.50
August	$5.40	$4.95	$5.57	$5.11
September	$5.57	$5.10	$5.74	$5.26
October	$5.71	$5.23	$5.89	$5.40
November	$6.12	$5.61	$6.32	$5.79
December	$6.05	$5.55	$6.24	$5.72
Annual Average	**$5.77**	**$5.28**	**$5.94**	**$5.45**

For the purposes of the 2005 Proposed Determination, downstream pipeline and local distribution tariff charges from forecast pricing hub locations to individual plant locations throughout the WECC were calculated and then utilized to arrive at a contract specific delivered fuel price forecast. In previous revenue requirement determinations, gas prices were forecast to major gas price hub locations only, such as the Southern California Border, the PG&E City-gate and others such as the Rockies and AECO "C" in Alberta.

The effect of including transportation costs downstream of the hub locations is that total fuel costs associated with the Department's contracted plant locations, as well as the costs of fuel for all other plants within and outside of California, and in the WECC, increase. The mapping of downstream fuel transport charges to hub gas prices however more accurately aligns forecasted fuel costs with actual fuel costs at the plant level.

With respect to the Department's contracted plant facilities, a review of the plants determined that none of the facilities are expected to qualify for "backbone level" service (e.g. service that effectively bypasses the utility distribution system) should it be implemented in northern California by PG&E. Other non-DWR contracted plants located in northern California and within the PROSYM database will, however, be impacted (a discount of transportation rates of approximately $0.15 per Dth has been included in the recent "all parties" Gas Accord III settlement agreement) for those generators qualifying for "backbone level" service beginning in January 2005. If "backbone level" service is ultimately approved by the CPUC (Decision 03-12-061), the Department would incorporate these downstream intrastate tariff changes into natural gas forecasts used in future revenue requirement determinations. This 2005 Proposed Determination, however, does not incorporate the changes that such a bypass would create for downstream costs on the PG&E system.

At this time, the issue of bypassing utility gas distribution systems only applies to the PG&E service territory, as a result of the Gas Accord process that was first implemented within the PG&E service territory in 1998. The market structure that resulted from the Gas Accord unbundled the "backbone system" from the distribution and storage system, leading to the technical possibility that certain customers could bypass the distribution system and connect directly to the "backbone system". In the Southern California Gas and SDG&E service systems, the transportation, storage and distributions systems have not been unbundled, eliminating the likelihood of bypassing the distribution system and connecting directly to the "backbone system". Recent efforts focused on restructuring the Southern California Gas and SDG&E systems, particularly within the "Comprehensive Settlement Agreement" process, have not led to the development of an unbundled gas transportation network. It remains unclear when market structure changes, resulting in an unbundled gas transportation network, might be implemented. For the purposes of this 2005 Proposed Determination, the effects of bypass have not been considered in southern California.

HYDRO CONDITION ASSUMPTIONS

Normal hydrologic conditions are assumed for both California and the Pacific Northwest during 2005 and 2006. Neither the CEC nor the National Weather Service Northwest River Forecast Center has provided meaningful forecasts past the current 2004 water year. Therefore, DWR has projected normal hydroelectric dispatch for the 2005 Revenue Requirement period.

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 an 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 PLTPCs 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.

Revenue shares from the sale of excess energy, both the Department's and total IOU, are provided in Table D-12 below.

TABLE D-12
SALE OF EXCESS ENERGY

	DWR Volume	IOU Volume	Total Volume	DWR Revenue[1]	IOU Revenue[1]	Total Revenue[1]	Weighted Average Price
	(GWh)	(GWh)	(GWh)	(Millions of Dollars)	(Millions of Dollars)	(Millions of Dollars)	($/MWh)
Q1-2005	1,025	2,629	3,654	$ 47	$ 117	$ 164	$ 45
Q2-2005	903	2,646	3,548	$ 31	$ 89	$ 120	$ 34
Q3-2005	917	1,790	2,707	$ 49	$ 81	$ 130	$ 48
Q4-2005	1,009	2,365	3,374	$ 52	$ 118	$ 170	$ 51
Total	3,854	9,429	13,283	$ 179	$ 405	$ 585	$ 44

[1]Revenue totals are presented on an accrual basis.

GAS COLLATERAL COSTS

In 2005, the Department has identified, as a separate line item, cash collateral provided in connection with gas purchases. The Department analyzed the NYMEX margin requirements to secure futures on the highest seven months of fuels requirements. Margin requirements of the NYMEX exchange are listed by the exchange. The margins are exchange requirements based upon a fixed price per contract. In order to come up with a total margin cost, anticipated fuel volumes from June through December 2005 were utilized. These anticipated fuel volumes are determined through the use of the production simulation analysis supporting this 2005 Proposed Determination. Based upon these volumes, margin requirements to purchase futures for the fuels program from June through December 2005 would be $70 million. This amount is nearly equivalent to the 2004 collateral requirement of $71 million.

CONTRACT ASSUMPTIONS

The Department, in cooperation with representatives of the Attorney General's office, the Commission's staff, staff of the Electricity Oversight Board, and representatives of the Governor's staff, has continued its efforts to modify terms and conditions of the Department's long-term contracts consistent with the requirements of the Act. While certain contract terms and conditions relative to the Calpine Long Term Commodity Sale have been amended since the September 18, 2003 Determination, those changes have not had an impact on the Department's revenue requirements. Four of the remaining contracts have yet to be renegotiated from their original terms.

Table D-13 provides a listing of all of the original 2001 long-term energy contracts, describing the term and capacity associated with each contract and the IOU to which the contract has been allocated. In addition, DWR entered into a contract with the Kings River Conservation District in December 2002 relative to 90 MW of capacity for 10 years, currently expected to begin in May 2005. Regarding the Amended and Restated Demand Reserves Purchase Agreement with the California Power Conservation and Financing Authority, projected costs for the 2005 Revenue Requirement period were increased to $39.1 million from the 2004 projected cost of $26.1M, based on an assumed 250 MW increase in maximum capacity commensurate with the 250 MW increase in maximum capacity elected by the counterparty for 2004. Detailed contract terms can be found on the CERS website, http://cers.water.ca.gov.

TABLE D-13
LONG TERM CONTRACT LISTING

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
Allegheny Energy Supply Company, LLC	3/23/2001 Renegotiated 6/10/03	1/1/2005	12/31/2005	750	SCE
"	" "	1/1/2006	12/31/2011	800	SCE
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

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
Calpine Energy Services, L.P. (North San Jose Project)	6/11/2001 Renegotiated on 4/22/02	3/5/2003	3/5/2006	184	PG&E
Clearwood Electric Company, LLC	6/22/2001 Renegotiated on 11/20/02	Upon COD, est 7/05	12/31/2012	25 to 30	PG&E
Coral Power, LLC	5/24/2001	1/1/2004	12/31/2005	400	PG&E
"	"	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
El Paso Merchant Energy	2/13/2001 Renegotiated on 6/24/2003	2/9/2001	12/31/2005	50	SCE
"	"	"	"	50	PG&E
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
"	"	6/01/03	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
Morgan Stanley Capital Group	2/14/2001 Renegotiated on 7/10/03	1/1/2004	12/31/2005	35	SDG&E
PacifiCorp	7/6/2001	7/1/2004	6/30/2011	300	PG&E
PG&E Energy Trading	5/31/2001 Renegotiated on 10/1/02	10/1/2001	9/30/2011	66.6	SCE
Santa Cruz County	9/13/2001 Renegotiated on 12/19/02 TERMINATED on 1/1/04	Upon COD, Est 12/31/03	6/30/2007	Was 3	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

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
"	"	1/1/2004	9/30/2011	700; drops to 400 in Mar-May of 2004-2007, and permanently starting Jan 2008	SCE
Soledad Energy LLC	4/28/2001; terminated on 3/27/02; Revision Executed on 6/27/02	9/09/2002	10/31/2006	13	PG&E
Sunrise Power Company, LLC	6/25/2001 Renegotiated on 12/31/02	6/01/03	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
"	"	7/1/2003	12/31/2005	450	SDG&E
"	"	1/1/2006	12/31/2006	450	SDG&E
"	"	1/1/2007	12/31/2007	450	SDG&E
"	"	1/1/2008	12/31/2008	275	SDG&E
"	"	1/1/2009	12/31/2009	275	SDG&E
"	"	1/1/2010	12/31/2010	275	SDG&E
"	"	7/1/2003	12/31/2010	50	SDG&E
"	"	7/1/2003	12/31/2007	1175	SDG&E
"	"	1/1/2008	12/31/2010	1045	SDG&E

EL PASO ENERGY SETTLEMENT AGREEMENT

On June 24, 2003, the State of California, Office of the Attorney General, executed a Master Settlement Agreement with El Paso Energy that resulted in the Department's receipt of nearly $161 million on June 28, 2004. The receipt of $161 million is a compilation of several components specified within the Master Settlement Agreement, which include nearly $109 million related to proceeds from El Paso Energy's requisite corporate stock sale, nearly $50 million in monthly contract price reductions and associated interest for the period beginning July 2003 through June 2004, and $2.1 million to reimburse the Department for attorneys' fees and costs related to this settlement. Amendment #1 to the El Paso power purchase agreement also provides for price reductions from May 2004 through the contract's expiration in December 2005, yielding an additional $75 million in contract cost reductions.

In addition, beginning in July 2004 the Department will receive semi-annual cash payments as deferred consideration from El Paso Energy. These semi-annual cash payments in the amount of $5.5 million will be paid by El Paso Energy to the Department each January and July for the next 20 years (40 payments of $5.5 million, totaling approximately $219 million over 20 years), ending with a final payment in January of 2024. Documents reflecting the terms of the Master Settlement Agreement with El Paso Energy are included within the administrative record supporting this 2005 Proposed Determination.

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). During the 2005 Revenue Requirement period, it is projected that the Natural Gas Purchase Contract will result in savings or revenue (in the event that the contracted fuel volume is re-sold in the natural gas market) of approximately $34 million, based on the difference between the contract fuel price of $3.85 and the Department's projected average annual fuel price of $5.77.

Documents reflecting the terms of the Settlement Agreement with Williams are included within the administrative record supporting this 2005 Proposed Determination.

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 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.

As described in Table D-13 of this Determination, the Department has renegotiated 21 of the remaining original contracts entered into in 2001 and has terminated five additional contracts for cause. As shown on Table D-13, one of these contracts was terminated for cause since the September 18, 2003 Determination. The Department has continued efforts to renegotiate additional contracts. The Department continues to monitor its contracts and determine if there are 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 revenue requirement 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 new long-term contracts from 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 net savings in the revenue requirement or overall ratepayer costs.

ADMINISTRATIVE AND GENERAL COSTS

The Department's administrative and general costs of $45 million consist of $41 million for appropriated budget expenditures and $4 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.

The $41 million for calendar year 2005 appropriated budget expenditures is based on one-half of the 2004-2005 fiscal year budget ($46 million), per the Budget Act, and one-half of the anticipated budget ($36 million) for fiscal year 2005-2006. The amount appropriated for 2004-2005 includes funds for labor and benefits, professional service costs, and $21 million for pro-rata charges for services provided to the power supply program by other State agencies. The pro-rata charge includes $10 million that is retroactive to the 2002-2003 fiscal year and $11 million for the 2004-2005 fiscal year. Appropriated costs in the 2005-2006 fiscal year are expected to decrease as there will be no retroactive pro-rata charge.

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 Indentures and Supplemental Bond Indentures for each series of Bonds. The materials are included within the administrative record supporting this 2005 Proposed Determination.

For purposes of calculating the interest earnings on all account balances, the Department assumes a 4.06 percent rate for the Debt Service Reserve Account and a 2.0 percent earnings rate for all other accounts during the 2005 Revenue Requirement period.

The Department projects that the amount of Bond Charge Revenues required for the 2005 Revenue Requirement period will be $886 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. These materials are included within the administrative record supporting this 2005 Proposed Determination. 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 AB1X. 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 to include in its revenue requirements amounts sufficient to cause a Minimum Operating Expense Available Balance ("MOEAB") to be on deposit in the Operating Account. The MOEAB is to be calculated by the Department at the time of each determination of a revenue requirement and for 2003 and successive calendar years 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 then current revenue requirement period, taking into account a range of possible future outcomes (i.e., “stress cases”).

For the purposes of this 2005 Proposed Determination, the MOEAB is determined by the Department to be $317 million.

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 2005 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 will 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 2005 Revenue Requirement period is determined by the Department to be $544 million, reflecting an amount equal to 12 percent of the Department’s projected annual Operating Expenses.

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 costs under the Long-Term Priority Contracts, 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 2005 Revenue Requirement period at 4.0 percent for the purpose of calculating required deposits to the Bond Charge Payment Account. For the 2005 Revenue Requirement period, the minimum account balance amount ranges from $76 to $78 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 2005 Revenue Requirement period at 4.0 percent for the purpose of calculating debt service accruals in the Bond Charge Payment Account. For the 2005 Revenue Requirement period, the minimum account balance amount ranges from $335 to $932 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 2005 Revenue Requirement period, the Department will calculate projected interest on unhedged Variable Rate Bonds at 4.0 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 2005 Revenue Requirement period, the Debt Service Reserve Requirement is determined to be $927 million.

SENSITIVITY ANALYSIS

The Rate Agreement requires the Department to evaluate its costs and cash flows on a monthly basis and to file revised Retail Revenue Requirements with the Commission 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 a 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, file and initiate the Commission process regarding the new revenue requirement and allocation of 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 lag 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, 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").

The Department comprehensively analyzed two Stress Cases in this 2005 Proposed Determination.

CASE 1

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

Higher costs are driven primarily by increased fuel costs. This Stress Case utilizes a natural gas price forecast that is double the level of the base case forecast from DWR's long term gas forecasting model.[18]. 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 2005 and 2006.

Lower loads are estimated in this case by assuming cooler-than-normal summers during 2005 and 2006, 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 2005 and 2006 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 2005 and 2% in 2006. 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. This Stress Case utilizes a natural gas price forecast that is double the level of the base case forecast from DWR's long term gas forecasting model. 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 2005 and 2006. URG is further decreased by assuming an unplanned outage at one southern California nuclear power plant unit from January 2005 through March 2005 and at one northern California nuclear power plant unit from April 2005 through March 2006. 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 2005 and 1.4% higher in 2006. 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 2005 and 2006. 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 2005 and 2006 by 4.4%, 4.8%, 6.8%, and 5.9% for June, July, August, and September respectively.

[18] Based on Gas Daily Monthly Index Prices, monthly gas prices have more than doubled year over year 10 times from 1999 though 2003.

E. KEY UNCERTAINTIES IN THE REVENUE REQUIREMENT DETERMINATION

There are a number of uncertainties facing the Department that may require material changes to its revenue requirements for the 2005 Revenue Requirement period after this Proposed 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. Legal challenges to DWR's administrative process;
   b. Administrative and legal challenges to DWR's revenue requirements;
   c. Litigation regarding inclusion of DWR Priority Contract Costs in its Retail Revenue Requirement;
   d. Application and enforcement of CPUC's Bond Charge rate covenant; and
   e. DWR's assessment of these risks.

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. Priority 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;
   b. Transition risks; and
   c. DWR administrative expenses appropriation by State Legislature

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;
   f. "Block Forward Contracts" consolidated actions;
   g. Action requiring DWR to pay for power ordered for PG&E and SCE;
   h. Actions affecting retail rates; and
   i. Impact of these factors

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; and
    b. Lack of dispatch coordination between IOUs and DWR

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;
    c. Recent State Legislation; and
    d. Possible Federal Legislation or action.

F. JUST AND REASONABLE DETERMINATION

THE 2003 DETERMINATION

The 2003 Determination was published on August 16, 2002 and provided extensive material leading to the determination by the Department that its revenue requirement for 2003 as determined therein was just and reasonable. Included in that material was background information on the situation California was facing, the Legislative actions taken and the gubernatorial direction leading to the Department's role and participation in power procurement on behalf of retail customers in the IOUs' service territories. Also included was a discussion of the meaning of just and reasonable, and a discussion of the California Administrative Procedure Act. In finding the 2003 Determination to be just and reasonable, the Department discussed the long-term power purchase contracts including the existing market conditions, the portfolio planning process, the procurement activities and the negotiating environment and other factors leading to the Determination. That information is, to the extent applicable and not modified herein, incorporated in this 2005 Proposed Determination by reference and will not be repeated herein. The material referenced is included in the administrative record of this 2005 Revenue Requirement proceeding. For further information please refer to Section H. On August 19, 2004, DWR issued a Reconsideration of the Just and Reasonableness of its 2003 Determination. A copy of the Reconsideration is included in the administrative record of this 2005 Revenue Requirement proceeding. The Department has also included its Notice of Reconsideration in the administrative record supporting of this 2005 Revenue Requirement proceeding.

THE 2003 SUPPLEMENTAL DETERMINATION

Subsequent to August 16, 2002, new information became available to the Department. Such new information, either provided by the IOUs, as a result of experience from actual transactions, or emanating from a change in certain assumptions, led to the 2003 Supplemental Determination, which was published on July 1, 2003. The just and reasonable determination in the 2003 Supplemental Determination is, to the extent applicable and not modified herein, incorporated in this 2005 Proposed Determination by reference and will not be repeated herein. The material referenced is included in the administrative record of this 2005 Revenue Requirement proceeding. For further information please refer to Section H.

THE 2004 DETERMINATION

The 2004 Determination was published on September 18, 2003 Determination provided extensive material leading to the determination by the Department that its revenue requirement for 2004 as determined therein was just and reasonable. In finding the 2004 Determination to be just and reasonable, the Department discussed the long-term power purchase contracts including the 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 2005 Proposed Determination by reference and will not be repeated herein. The material referenced is included in the administrative record of this 2005 Revenue Requirement proceeding. For further information please refer to Section H.

THE 2004 SUPPLEMENTAL DETERMINATION

Subsequent to September 18, 2003, new information became available to the Department. Such new information, either provided by the IOUs, as a result of experience from actual transactions, or emanating from a change in certain assumptions, led to the 2004 Supplemental Determination, which was published on April 16, 2004. The just and reasonable determination in the 2004 Supplemental Determination is, to the extent applicable and not modified herein, incorporated in this 2005 Proposed Determination by reference and will not be repeated herein. The material referenced is included in the administrative record of this 2005 Revenue Requirement proceeding. For further information please refer to Section H.

THE 2005 PROPOSED DETERMINATION – DEVELOPMENT OF THE DETERMINATION

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

On October 10, 2003, the Department provided existing assumptions underlying its modeling efforts for the calendar years 2004 through 2007 to each IOU subject to nondisclosure requirements. DWR requested each IOU to review and comment with respect to the information included therein. IOU-specific assumptions and related projections included, but were not limited to, load data, Direct Access Departing Load information, retained generation including bilateral contracts, QF information and owned generation. The Department also provided lists of the DWR Contracts administered by each IOU along with certain operating data and information pertaining to off-system sales. Each IOU's independent data review and compilation of specific comments was scheduled for completion by November 15, 2003.

On November 19, 2003, the Department conducted a conference call with all IOUs to discuss the status of the Department's request for review and comment on modeling assumptions it had provided to the IOUs.

On December 10, 2003, the Department received SCE's initial comments regarding the 2005 planning assumptions and PROSYM modeling. On January 16, 2004, the Department received SDG&E's initial comments regarding the 2005 planning assumptions and PROSYM modeling. And on February 2, 2004, the Department received PG&E's initial comments regarding the 2005 planning assumptions and PROSYM modeling.

The information obtained from the IOUs, much of which is considered by each individual IOU as confidential and provided under a non-disclosure agreement, became the basis of the Department's analytical and forecasting efforts related to this 2005 Proposed Determination. The Department also considered other important criteria such as Commission Decisions and Bond Trust 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 2005 Proposed Determination.

Following the Department's receipt of each IOU's initial comments, the Department conferred with each IOU to develop a mutual understanding regarding key assumptions underlying this Proposed Determination. Each IOU has had the opportunity to provide and has provided significant input to the assumptions underlying this 2005 Proposed Determination.

The long-term contracts contained in this 2005 Proposed Determination were reviewed extensively in the 2003 Determination, with updates for renegotiation efforts reviewed in the 2003 Supplemental Determination, the 2004 Determination and the 2004 Supplemental Determination. This 2005 Proposed Determination includes and reflects the positive results of the Department's continuing efforts to renegotiate contracts. This inclusion is limited to efforts that have been completed and are not subject to ongoing regulatory review and approval. A discussion of the assumptions used in the development of this 2005 Proposed Determination is found in Section D.

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

The Department has issued this 2005 Proposed Determination of Revenue Requirements for public comment under the Regulations promulgated pursuant to the California Administrative Procedures Act. Under the Regulations, any determination that this 2005 Proposed Determination of Revenue Requirements 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 2005 Determination of Revenue Requirements that differs from this 2005 Proposed Determination of Revenue Requirements.

G. 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 2005 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

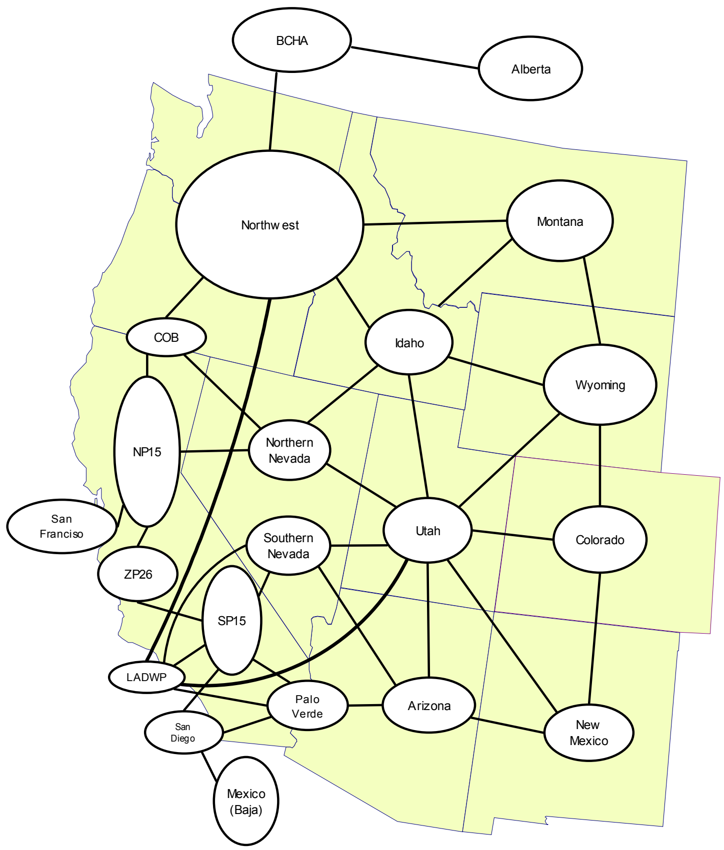
WECC electricity markets sometimes experience binding transmission constraints. Binding transmission constraints occur at times when transmission capacity on a specific linear path is fully utilized and no additional energy can be transported via that line or path. During such times, low-cost generators 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 2005 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. The Department's Long-Term Power Contracts are available for viewing 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 Design 2002 ("MD02") 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 purchase CRRs to assure the delivery of energy from certain of the Department's long-term energy supply contracts or else risk the possibility of failure to deliver either must-take energy or energy which would otherwise be economically dispatched from the Department's contracts.

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 CRR 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 would increase the Department's revenue requirement beyond the levels that would otherwise exist. To the extent that others purchase CRRs and such purchases 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 and the three utilities' separate revenue requirement for the replacement energy they may need to acquire is unknown at this time.

At present, the Department does not expect that the CAISO will implement the LMP and CRR provisions of MD02 until after calendar year 2005. As a result, the Department does not anticipate the MD02 implementation to affect the Department's 2005 Determination of Revenue Requirements. The Department intends to monitor the CAISO's process for evaluation and implementation of LMP and CRR to better 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 2005 through December 2005.
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.

H. ANNOTATED REFERENCE INDEX OF MATERIALS UPON WHICH THE DEPARTMENT RELIED TO MAKE DETERMINATIONS

Volume	Record Number	Date	Record Title
DWR05pRR		9/17/2003	CONFIDENTIAL - NOT FOR PUBLIC RELEASE: Record of Coordination - Meeting with IOUs to discuss 2005 Revenue Requirement planning, dated September 17, 2003
DWR05pRR		10/10/2003	California Department of Water Resources Transmittal of 2005 Revenue Requirement Assumptions and Request for Review and Comment, dated October 10, 2003
DWR05pRR		11/19/2003	Record of Coordination - Conference Call to discuss the 2005 revenue requirement process, between F. Perdue et. al. (NCI), DWR, Southern California Edison Company, and San Diego Gas & Electric Company; Pacific Gas and Electric Company was unable to participate, dated November 19, 2003
DWR05pRR		12/8/2003	CONFIDENTIAL - NOT FOR PUBLIC RELEASE: Southern California Edison's Comments on Base Case Assumptions for California Department of Water Resources' 2005 Revenue Requirements Determination, dated December 8, 2003
DWR05pRR		1/16/2004	CONFIDENTIAL - NOT FOR PUBLIC RELEASE: San Diego Gas & Electric Company's Comments on Assumptions and Modeling for Development of the California Department of Water Resources' 2005 Revenue Requirement, dated January 16, 2004
DWR05pRR		1/22/2004	CPUC Decision 04-01-049 - Opinion Regarding Western Area Power Administration Interest, dated January 22, 2004
DWR05pRR		1/30/2004	CONFIDENTIAL - NOT FOR PUBLIC RELEASE: Pacific Gas and Electric Company's Comments on Base Case Assumptions for California Department of Water Resources' 2005 Revenue Requirements Determination (PG&E: "Response to California Department of Water Resources First Data Request"), dated January 30, 2004

Volume	Record Number	Date	Record Title
DWR05pRR		3/8/2004	CONFIDENTIAL - NOT FOR PUBLIC RELEASE: Southern California Edison's Response to the California Department of Water Resources February 24, 2004 Data Request, dated March 8, 2004
DWR05pRR		3/10/2004	Record of Coordination - Ron Oechsler (NCI) with Ted Mureau (SCE) regarding SCE 2004 sales forecast, dated March 10, 2004
DWR05pRR		3/18/2004	Record of Coordination - DWR Data Request to Pacific Gas and Electric Company Pertaining to Generation Availability, dated March 18, 2004
DWR05pRR		3/18/2004	Record of Coordination - DWR Data Request to Southern California Edison Company Pertaining to Generation Availability, dated March 18, 2004
DWR05pRR		3/18/2004	Record of Coordination - DWR Data Request to San Diego Gas & Electric Company Pertaining to Generation Availability, dated March 18, 2004
DWR05pRR		3/19/2004	California Energy Commission Energy Facility Status, dated March 19, 2004
DWR05pRR		3/24/2004	Record of Coordination - Gordon Pickering (NCI) with Alice Herron (PG&E) regarding DWR Hedging Program - Margin Account Modeling, dated March 24, 2004
DWR05pRR		3/25/2004	Record of Coordination - Gordon Pickering (NCI) with Alice Herron (PG&E) regarding DWR Hedging Program - Margin Account Question, dated March 25, 2004
DWR05pRR		3/25/2004	Pacific Gas and Electric Company's Response to California Department of Water Resources' March 18, 2004 Data Request Questions 1-3 (Nina Bubnova), dated March 25, 2004
DWR05pRR		3/26/2004	Western Area Power Administration's forecast of capacity and energy for load and resources for the 12-month period beginning March 1, 2004, dated March 26, 2004
DWR05pRR		3/30/2004	CONFIDENTIAL - NOT FOR PUBLIC RELEASE: Record of Coordination - Email from Jim Olson with CDWR to CDWR and NCI staff regarding CDWR-PG&E Stipulation, dated March 30, 2004

Volume	Record Number	Date	Record Title
DWR05pRR		3/30/2004	Record of Coordination - Email from Jeff Huang transmitting San Diego Gas and Electric Company's Responses to California Department of Water Resources' March 18, 2004 Data Request Questions 1 & 2, dated March 30, 2004
DWR05pRR		3/30/2004	Record of Coordination - Email from Robert Anderson with San Diego Gas and Electric Company's Responses to California Department of Water Resources' March 18, 2004 Data Request Questions 1 & 2, dated March 30, 2004
DWR05pRR		3/31/2004	Record of Coordination - Email from Michael Strong with San Diego Gas and Electric Company's Responses to California Department of Water Resources' March 18, 2004 Data Request Question 3, dated March 31, 2004
DWR05pRR		4/1/2004	PG&E filing with the Supreme Court of California: Petition for Writ of Review. Seeks to overturn CPUC decisions on the amount and source of interest relating to WAPA underpayments; dated April 1, 2004
DWR05pRR		4/4/2004	CONFIDENTIAL - NOT FOR PUBLIC RELEASE: California Energy Resources Scheduling Division Long-Term Contracts Overview - March 2004, dated April 9, 2004
DWR05pRR		4/9/2004	Southern California Edison's Response to the California Department of Water Resources March 18, 2004 Data Request, dated April 9, 2004
DWR05pRR		4/12/2004	Record of Coordination - Email from Ron Oechsler relating to WAPA Forecast, dated April 12, 2004
DWR05pRR		4/13/2004	Record of Coordination - Email from Ron Oechsler relating to SDG&E economic assumptions, dated April 13, 2004
DWR05pRR		4/19/2004	State of California Department of Water Resources Supplemental Determination of Revenue Requirements for the Period January 1, 2004 through December 31, 2004, including by reference materials contained within Section G - Annotated Reference Index of Materials Upon Which the Department Relied to Make Determinations, dated April 16, 2004

Volume	Record Number	Date	Record Title
DWR05pRR		4/22/2004	Motion of Joint Settling Parties for Waiver of Rule 51.2 and Adoption of Settlement Agreement, dated April 22, 2004
DWR05pRR		4/23/2004	Southern California Edison Data Request No. 5 to the California Department of Water Resources, dated April 23, 2004
DWR05pRR		4/26/2004	Press Release - "Governor Schwarzenegger Announces $280 Million Refund from Dynegy," dated April 26, 2004
DWR05pRR		4/28/2004	Governor Arnold Schwarzenegger letter to Michael Peevey and the Governor's Press Release regarding Electricity Priorities. The Governor encouraged Utility negotiated long-term power contracts with recovery, as a means to attract new generation. He urged the 15% reserve margin of the CPUC to be accelerated from 2008 to 2006. He supports core/non-core customers and a direct access availability for large customers to negotiate their own energy supply contracts.
DWR05pRR		4/28/2004	CPUC President Michael Peevey's letter responding to Governor Schwarzenegger and CPUC press release, dated April 28, 2004
DWR05pRR		4/28/2004	Pacific Gas and Electric Company Data Request No. 5 to California Department of Water Resources, dated April 28, 2004
DWR05pRR		4/29/2004	CONFIDENTIAL DRAFT - NOT FOR PUBLIC RELEASE: Department of Water Resources' Natural Gas Forecast and Fuels Assumptions for the 2005 Revenue Requirements, dated March 4, 2004
DWR05pRR		4/29/2004	Peter Garris letter to Commissioner Lynch, et al. regarding Draft Decisions Addressing Petition of SCE for Modification of Decision 04-01-028. This relates to the allocation of the bond charge between the IOUs. DWR believes either the existing allocation or the SCE requested allocation to be reasonable however, language in the ADD of Commissioner Lynch has language the Department feels should be revised; dated April 29, 2004

Volume	Record Number	Date	Record Title
DWR05pRR		5/5/2004	CONFIDENTIAL - NOT FOR PUBLIC RELEASE: California Department of Water Resources' Response to Southern California Edison Data Request No. 5, dated May 5, 2004
DWR05pRR		5/6/2004	California Department of Water Resources' Response to Pacific Gas and Electric Company Data Request Questions 1-7, dated May 6, 2004
DWR05pRR		5/6/2004	California Department of Water Resources' letter to the California Public Utilities Commission, subject: Implementation of the Supplemental Revenue Requirement Determination for 2004, dated May 6, 2004
DWR05pRR		5/7/2004	Pacific Gas and Electric Company Data Request No. 6 to California Department of Water Resources, dated May 7, 2004
DWR05pRR		5/10/2004	Memoranda to: Mark Huffman-Pacific Gas and Electric Company; James P. Scott Shotwell, Southern California Edison; Meredith Allen, San Diego Gas & Electric; and Andrew Ulmer, Simpson Partners from Frank Perdue, Navigant Consulting, Inc. transmitting for review and comment the "2005 Revenue Requirement Determination CDWR CD Release of Financial Model and ProSym Files Protected Materials Not for Distribution," dated May 10, 2004 CONFIDENTIAL - NOT FOR PUBLIC RELEASE: Consultant's Financial Model and PROSYM Output Run 46, PROSYM Output Run 46 Sensitivity Case 1, and PROSYM Output Run 46 Sensitivity Case 2 - Proprietary Model and Confidential Data contained are not for public release - Protected under relevant Non Disclosure Agreements, dated May 10, 2004
DWR05pRR		5/10/2004	Pacific Gas and Electric Company's Comments on the California Department of Water Resources' Supplemental Determination of Revenue Requirements for 2004 filed at the California Public Utilities Commission (A.00 11 038), dated May 10, 2004

Volume	Record Number	Date	Record Title
DWR05pRR		5/10/2004	Southern California Edison Company's Comments on the Implementation of DWR's Supplemental 2004 Revenue Requirement Determination filed at the California Public Utilities Commission (A.00 11 038), dated May 10, 2004
DWR05pRR		5/10/2004	Opening Comments of San Diego Gas and Electric Company filed at the California Public Utilities Commission (A.00 11 038), dated May 10, 2004
DWR05pRR		5/13/2004	California Department of Water Resources' Responses to Pacific Gas and Electric Company Data Request Set Number 6, dated May 13, 2004
DWR05pRR		5/17/2004	California Department of Water Resources' Supplemental Responses to Pacific Gas and Electric Company Data Request Set Number 6, dated May 17, 2004
DWR05pRR		5/17/2004	California Department of Water Resources' letter to the California Public Utilities Commission, subject: Comments of the Investor-Owned Utilities Concerning Implementation of the Department of Water Resources' 2004 Supplemental Revenue Requirements, dated May 17, 2004
DWR05pRR		5/17/2004	Pacific Gas and Electric Company's Reply Comments on the California Department of Water Resources' Supplemental Determination of Revenue Requirements for 2004 filed at the California Public Utilities Commission (A.00 11 038), dated May 17, 2004
DWR05pRR		5/17/2004	Southern California Edison Company's Reply Comments on the Implementation of DWR's Supplemental 2004 Revenue Requirement Determination filed at the California Public Utilities Commission (A.00 11 038), dated May 17, 2004
DWR05pRR		5/17/2004	Reply Comments of San Diego Gas and Electric Company filed at the California Public Utilities Commission (A.00 11 038), dated May 17, 2004
DWR05pRR		5/18/2004	Record of Coordination - Email from Brian Grubbs to PG&E providing response to phone call questions on 2005 Revenue Requirement documents, dated May 18, 2004

Volume	Record Number	Date	Record Title
DWR05pRR		5/19/2004	Department of Water Resources Electric Power Fund Financial Statements as of March 31, 2004, prepared May 19, 2004
DWR05pRR		5/20/2004	California Department of Water Resources' "Notice of Reconsideration of the just and reasonable determination made in connection with its August 16, 2002 Determination of Revenue Requirements for the Period January 1, 2003 Through December 31, 2003 with Reexamination and Re-determination for the Period January 17, 2001 Through December 31, 2002," dated May 20, 2004
DWR05pRR		5/20/2004	California Hydroelectric Energy Outlook, California Energy Commission Staff Paper, dated May 20, 2004
DWR05pRR		5/24/2004	California Department of Water Resources' letter to the CPUC regarding the motion for adoption of a settlement agreement entered into by Pacific Gas and Electric Company, Southern California Edison Company, and The Utility Reform Network in Application 00-11-038 et al., dated May 24, 2004
DWR05pRR		5/24/2004	CPUC Advice Letter 2471-E regarding 2004 gas supply plan for the State of California Department of Water Resources tolling agreements, dated May 24, 2004
DWR05pRR		5/25/2004	DWR informal data request to Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company Pertaining to the DWR 2005 Revenue Requirement Process, dated May 25, 2004
DWR05pRR		5/27/2004	CPUC Decision 04-05-054: "Opinion Denying Petition To Modify Decision 04-01-028." The Commission denies SCE's petition to change the bond allocation methodology established in prior orders and maintains the equal-cents-per-kWh method.
DWR05pRR		6/1/2004	Record of Coordination - DWR's Discussion of Variances Between Actual and Projected Values 2001-2002 & 2003 Revenue Requirement periods, dated June 1, 2004

Volume	Record Number	Date	Record Title
DWR05pRR		6/4/2004	CPUC Assigned Commissioner's Ruling and Scoping Memo, R.04-04-003, dated June 4, 2004
DWR05pRR		6/4/2004	CONFIDENTIAL - NOT FOR PUBLIC RELEASE: Pacific Gas and Electric Company's Response to California Department of Water Resources' May 25, 2004 informal request, dated June 4, 2004
DWR05pRR		6/7/2004	CONFIDENTIAL - NOT FOR PUBLIC RELEASE: Record of Coordination Email from Brian Grubbs to Michael Strong with DWR Response to SDG&E Request for ProSym data, dated June 7, 2004
DWR05pRR		6/9/2004	CONFIDENTIAL - NOT FOR PUBLIC RELEASE: SCE's Response to California Department of Water Resources' May 25, 2004 informal request, dated June 9, 2004
DWR05pRR		6/9/2004	CPUC Decision 04-06-003, Opinion on Pacific Gas and Electric Company's December 4, 2003 Petition to Modify Decision 02-10-062, R.01-10-024, dated June 9, 2004
DWR05pRR		6/9/2004	CPUC Decision 04-06-011, Opinion Approving Motion of San Diego Gas & Electric Company (U 902 E) for Approval to Enter into New Electric Resource Contracts Resulting from SDG&E's Grid Reliability Request for Proposal, R.01-10-024, dated June 9, 2004
DWR05pRR		6/9/2004	CPUC Decision 04-06-013, Interim Opinion Adopting Methodology for Consideration of Transmission Costs in RPS Procurement, I.00-11-001, dated June 9, 2004
DWR05pRR		6/9/2004	CPUC Decision 04-06-014, Opinion Adopting Standard Contract Terms and Conditions, R.04-04-026, dated June 9, 2004
DWR05pRR		6/9/2004	CPUC Decision 04-06-015, Opinion Adopting Market Price Referent Methodology, R.04-04-026, dated June 9, 2004
DWR05pRR		6/10/2004	CPUC Assigned Commissioner's Ruling Regarding Reliability Issues, R.04-04-003, dated June 10, 2004

Volume	Record Number	Date	Record Title
DWR05pRR		6/11/2004	Pacific Gas and Electric Company's Preliminary Comments on the California Department of Water Resources' Notice of Reconsideration of Revenue Requirement Determinations for 2001, 2002 and 2003, dated June 11, 2004
DWR05pRR		6/11/2004	CONFIDENTIAL - NOT FOR PUBLIC RELEASE: Record of Coordination - Email from SCE to Jim McMahon regarding transmission loss calculations, dated June 11, 2004
DWR05pRR		6/11/2004	Record of Coordination - Jim McMahon with Matt Masters, PG&E, regarding sales forecast updates, dated June 11, 2004
DWR05pRR		6/11/2004	Record of Coordination - Jim McMahon with Greg Katsapsis, SCE regarding sales forecast updates, dated June 11, 2004
DWR05pRR		6/11/2004	Record of Coordination - Jim McMahon with Colin Cushnie, SCE regarding sales forecast updates, dated June 11, 2004
DWR05pRR		6/15/2004	CONFIDENTIAL - NOT FOR PUBLIC RELEASE: Record of Coordination - Email from David Oliver, SCE, to Brian Grubbs, NCI, transmitting ProSym script modeling of SCE's Transition Contracts, dated June 15, 2004
DWR05pRR		6/15/2004	CPUC Workshop Report on Resource Adequacy Issues prepared by ALJ Michelle Cooke, R.01-10-024/R.04-04-003, dated June 15, 2004
DWR05pRR		6/16/2004	CPUC ALJ Ruling Clarifying Instructions on Long-Term Plan Filings, R.04-04-003, dated June 16, 2004
DWR05pRR		6/17/2004	Record of Coordination – Paul Luther - Correspondence and Meeting Summary: ProSym Run 47 Preparation; PG&E Generation Resources, dated June 17, 2004
DWR05pRR		6/17/2004	Record of Coordination – Paul Luther - Correspondence and Meeting Summary: ProSym Run 47 Preparation; SCE Generation Resources, dated June 17, 2004

Volume	Record Number	Date	Record Title
DWR05pRR		6/18/2004	Pacific Gas and Electric Company's response to DWR's June 16, 2004 Data Request, dated June 18, 2004
DWR05pRR		6/18/2004	CONFIDENTIAL - NOT FOR PUBLIC RELEASE: Record of Coordination - SDG&E's email response to DWR's June 16, 2004 Data Request, dated June 18, 2004
DWR05pRR		6/20/2004	CONFIDENTIAL - NOT FOR PUBLIC RELEASE: DWR Permanent Cost Allocation Comparison Exhibit, dated June 20, 2004
DWR05pRR		6/21/2004	CONFIDENTIAL - NOT FOR PUBLIC RELEASE: Record of Coordination - Email between Brian Grubbs, NCI, with Sharim Chaudhury and David Oliver, SCE, regarding SCE Transition Contracts, dated June 21, 2004
DWR05pRR		6/24/2004	Record of Coordination - Email Gordon Pickering with NCI staff regarding PacifiCorp Fuel Charges Forecast 2005-2025, dated June 24, 2004
DWR05pRR		6/24/2004	Record of Coordination - Conference call with NCI and SCE regarding SCE Transition Contracts, dated June 24, 2004
DWR05pRR		6/25/2004	Record of Coordination - Email string-NCI and SDG&E regarding DWR 2005 Revenue Requirement Process - SDG&E Calpeak Assumptions, dated June 25, 2004
DWR05pRR		7/1/2004	Record of Coordination – Email Keith Durand to Michael McCreery regarding IOU Renewable Procurement Plans Submitted to Procurement Review Group, dated July 1, 2004
DWR05pRR		7/1/2004	PG&E’s Energy Resource Recovery Account, A.03-08-004, Compliance Review Testimony for the June 1-December 31, 2003 Record Period (redacted), dated July 1, 2004
DWR05pRR		7/7/2004	Record of Coordination - Email string-NCI and Sempra Utilities regarding Gas price model input, dated July 7, 2004

Volume	Record Number	Date	Record Title
DWR05pRR		7/8/2004	Draft CPUC Resolution E-3875 addressing agency agreement for administration of Demand Reserves Partnership Agreement, dated July 8, 2004. (The CPUC deferred consideration from July 8 to August 19, 2004)
DWR05pRR		7/8/2004	CPUC Decision 04-07-025 (relating to Direct Access load growth principles), dated July 8, 2004
DWR05pRR		7/8/2004	CPUC Decision 04-07-028 (directing IOUs to consider transmission congestion and local reliability in scheduling and dispatch activities), dated July 8, 2004
DWR05pRR		7/8/2004	CPUC Resolution E-3831 (CRS for customer generation departing load), dated July 8, 2004
DWR05pRR		7/8/2004	CPUC Decision 04-07-037 (relating to long-term procurement planning issues): Order Modifying D.03-12-062 and D.04-01-050, and Denying Rehearing of D.03-12-062 and D.04-01-050 As Modified, dated July 8, 2004
DWR05pRR		7/22/2004	PG&E Notice of Availability of its Energy Recovery Bonds (ERB) Financing Application filed with the California Public Utilities Commission, dated July 22, 2004
DWR05pRR		7/23/2004	CPUC ALJ Ruling Establishing a Preliminary Schedule for the Proceeding (PG&E ERB Financing Application), A.04-07-032, dated July 23, 2004
DWR05pRR		8/1/2004	Record of Coordination – Email Marc Renson, PG&E, with Brian Grubbs, NCI and Chi Doan, CDWR regarding meeting to reconcile the 2003 generation and financial data for the CDWR contracts allocated to PG&E, dated August 1, 2004
DWR05pRR		8/2/2004	Record of Coordination – CERS, PG&E, and NCI meeting regarding true-up allocation of 2003 long-term contract costs, dated August 2, 2004
DWR05pRR		8/6/2004	Record of Coordination – Voicemail from PG&E to Brian Grubbs regarding Breakout of 2003 Costs, dated August 6, 2004

Volume	Record Number	Date	Record Title
DWR05pRR		8/19/2004	Reconsideration of the California Department of Water Resources' August 16, 2002 Just and Reasonable Determination made in connection with DWR's 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, issued on August 16, 2002, dated August 19, 2004
DWR05pRR		8/19/2004	CPUC Decision 04-08-050 - Opinion Implementing an Interim Allocation of the Supplemental 2004 Revenue Requirement Determination of the California Department of Water Resources, dated August 19, 2004
DWR05pRR		8/31/2004	Record of Coordination – Email Brian Grubbs, NCI with David Oliver, SCE and Ziyad Mansour, CDWR regarding capacity payment schedule for Sunrise, dated August 31, 2004
DWR05pRR		9/07/2004	Record of Coordination – Email Jim Olson, CDWR with Frank Perdue, NCI with revised information for G&A estimate supporting the 2005 Revenue Requirement, dated September 7, 2004.