State of California

Department of Water Resources

Revision to the 2005 Revenue Requirement Determination

For the Period

January 1, 2005, Through December 31, 2005

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

March 16, 2005

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A. THE REVISED 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 Revised Determination of Revenue Requirements for the period January 1, 2005 through December 31, 2005 (the "Revised 2005 Determination)". Capitalized terms used and not otherwise defined herein have the meanings given to such terms in the Rate Agreement or the Trust 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.

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 responsibility for 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 Department issued $11.263 billion of revenue bonds. The proceeds were applied to reimburse the General Fund, pay off 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 Revised 2005 Determination contains information on the amounts required to be recovered, on a cash basis, in the 2005 Revenue Requirement Period (calendar year 2005).

This Revised 2005 Determination takes into account preliminary actual results of Department operations through December 31, 2004.

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

For the 2005 Revenue Requirement Period, this Revised 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 hereby determines, on the basis of the materials presented and referred to by this Revised 2005 Determination (including the materials referred to in Section J), that its cash basis revenue requirement for 2005 is $4.658 billion, consisting of $3.808 billion in power revenues and $0.850 billion in bond revenues. These revisions result in a total reduction in the Department's 2005 Revenue Requirement of $166 million. This reduction is comprised of two components: a $91 million decrease in the Department's Power Charge Revenue Requirements; and a $75 million decrease in the Department's Bond Charge Revenue Requirements.

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 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 REVISED 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	1,128	1,031	98
3	Priority Contract Account	63	-	63
4	Operating Reserve Account	595	630	(35)
5	**Total Beginning Balance in Power Charge Accounts**	**1,786**	**1,660**	**125**
6	*Power Charge Accounts Operating Revenues*			
7	Power Charge Revenues from Bundled Customers[4]	3,808	4,272	(464)
8	Extraordinary Receipts[5]	11	52	(41)
9	Other Revenue[6]	236	273	(37)
10	Interest Earnings on Fund Balances	26	32	(6)
11	**Total Power Charge Accounts Operating Revenues**	**4,081**	**4,628**	**(547)**
12	*Power Charge Accounts Operating Expenses*			
13	Administrative and General Expenses	45	59	(14)
14	Total Power Costs	4,458	4,860	(402)
15	Gas Collateral Costs	52	37	15
16	Extraordinary Contract Expenses	(33)	-	(33)
17	**Total Power Charge Accounts Operating Expenses**	**4,522**	**4,956**	**(434)**
18	Net Operating Revenues	(441)	(327)	(114)
19	Net Transfers from/(to) Bond Charge Accounts & Adjustments	-	7	(7)
20	Total Net Revenues	(441)	(321)	(120)
21	**Ending Aggregate Balance in Power Charge Accounts**	**1,345**	**1,340**	**5**

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.	275	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.	555	595	(40)
Total Operating Reserves:	829	891	(61)

[1]Numbers may not add due to rounding.
[2]As included 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 REVISED 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	199	129	70
3	Bond Charge Payment Account	572	429	143
4	Debt Service Reserve Account	927	927	0
5	**Total Beginning Balance in Bond Charge Accounts**	**1,698**	**1,485**	**213**
6	*Bond Charge Accounts Revenues*			
7	Bond Charge Revenues[4]	850	891	(41)
8	Interest Earnings on Fund Balances	47	26	21
9	**Total Bond Charge Accounts Revenues**	**897**	**918**	**(21)**
10	*Bond Charge Accounts Expenses*			
11	Debt Service on Bonds	922	725	196
12	**Total Bond Charge Accounts Expenses**	**922**	**725**	**196**
13	Net Bond Charge Revenues	(25)	192	(217)
14	Net Transfers from/(to) Power Charge Accounts & Adjustments	-	-	-
15	Total Net Revenues	(25)	192	(217)
16	**Ending Aggregate Balance in Bond Charge Accounts**	**1,673**	**1,677**	**(4)**

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	237 - 834	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 included herein.
[3]As reflected in the 2004 Supplemental Determination.
[4]CRS Bond 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 further 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 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 and for the operation of the power supply program. 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 sufficient to provide moneys so that amounts on deposit in the Bond Charge Payment Account are sufficient to pay all Bond Related Costs 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 components of cost responsibility surcharges imposed by the Commission on customers other than those who buy power from the Department, for example, Direct Access or Community Choice Aggregation customers. To the extent these cost responsibility surcharges are imposed and remitted to DWR, the Department's Retail Revenue Requirement (Power Charges to be collected from bundled customers) is lower. This Revised 2005 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 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 maintains 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.

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.

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. The November 4, 2004 Determination was based in part on the Commission's implementation of the 2004 Supplemental Determination, resulting in a starting balance for the 2005 Revenue Requirement Period as projected therein.

THE NOVEMBER 4, 2004 DETERMINATION

On September 9, 2004, the Department published its Proposed Determination of Revenue Requirements for 2005 (the "Proposed Determination"), consistent with the requirements of Sections 80110 and 80134 of the California Water Code and provided information consistent with the requirements of the Rate Agreement.

On October 20, 2004, the Department issued a Notice of Additional Material to be Relied on in determining its revenue requirements, and made such additional material upon which it intended to rely available to interested persons. In conjunction with the Notice of Additional Material, the comment period for the Department's Proposed Determination was extended to October 27, 2004, allowing sufficient opportunity for interested persons to review and comment on the Proposed Determination and additional material.

During the period between September 9, 2004, and October 27, 2004, when comments were due, the Department responded to questions in an effort to assist interested persons in the review and understanding of the Proposed Determination and additional materials.

On September 30, 2004, the Department received comments on the Proposed Determination from SCE, SDG&E, and PG&E. The comments are summarized and the Department's responses are included in Section H of this Determination. On October 27, 2004, additional comments were received from PG&E and SCE. On October 29, 2004, the Department received comments from the CPUC's Energy Division. These comments are summarized, along with related responses from the Department, in Section H of this Determination.

The Proposed Determination, published on September 9, 2004, included preliminary actual operating results through June 2004. Following publication of the Department's Proposed Determination, preliminary actual operating results were compiled through September 30, 2004 and were incorporated in the November 4, 2004 Determination.

After review of all comments, the Department made the following changes in the November 4, 2004 Determination, as compared to the Proposed Determination.

(1) Data supporting the Department's market simulation effort was updated to reflect the renegotiated terms of its power purchase agreement with Clearwood Electric Company.

Clearwood Electric Company PPA	Capacity	Price	Term
Proposed Determination – Sep. 9	25 MW	$67.40	6/1/2005 – 12/31/2012
November 4, 2004 Determination	30 MW	$61.00	1/1/2007 – 12/31/2012

(2) SCE's utility-retained generation forecast was updated, based on comments received, to reflect signed capacity contracts for the 2005 calendar year.

(3) Assumptions related to the Department's demand reserve purchase agreement with the California Consumer Power and Conservation Financing Authority were revised.

CPA Demand Reserve Contract	Summer Capacity	2005 Total Cost
Proposed Determination – Sep. 9	750 MW	$39.1 Million
November 4, 2004 Determination	350 MW	$16.9 Million

(4) The 2005 gas price forecast was updated using an average of 10 days closing settlement futures prices for Henry Hub prior to and including October 22, 2004. The Proposed Determination based its gas price forecast on an average of 10 days closing settlement futures prices for Henry Hub prior to and including August 25, 2004.

Average 2005 Gas Prices at Henry Hub	$ / MMBtu
Proposed Determination – Sep. 9	$6.29
November 4, 2004 Determination	$7.35

(5) Assumptions related to SDG&E's direct access loads were updated, based on comments received, to reflect observed historical usage. These updates resulted in a change to the load shape within SDG&E's service area and affected the

timing of bond charge revenue receipts. Updates to SDG&E's direct access loads increased the bond charge revenue requirement in 2005 with a corresponding reduction in 2006.

(6) Based on FERC's approval (October 25, 2004) of a settlement agreement between Dynegy Power Marketing and the California Parties, the Department's projected beginning account balances for the 2005 Revenue Requirement Period were updated to reflect the receipt of $101.3 million in settlement proceeds during the fourth quarter of 2004.

In concert with the public comment process, the Department internally reviewed various aspects of its electric market simulation (PROSYM) to ensure that contract-specific terms/conditions and costs were accurately reflected therein. During this review, the Department identified necessary changes to the manner in which capacity payments, associated with several of its long-term power contracts, were seasonally "shaped" to reflect scheduled, inter-month price variations. These changes to long-term capacity payment shapes did not affect the total projected power cost included in the November 4, 2004 Determination but slightly decreased the Department's projected Minimum Operating Expense Available Balance ($282 million) due to the manner in which this amount was calculated. Section D includes additional discussion related to the Operating Account and the projected minimum balance therein.

Table B-1 summarizes the changes between the Proposed Determination and the November 4, 2004 Determination for the Power Charge revenue requirement and Power Charge Accounts. Table B-2 summarizes the changes between the Proposed Determination and the November 4, 2004 Determination for the Bond Charge revenue requirements and Bond Charge Accounts.

TABLE B-1
SUMMARY OF THE DEPARTMENTS 2005 POWER CHARGE REVENUE REQUIREMENTS AND POWER CHARGE ACCOUNTS, AS PUBLISHED IN THE NOVEMBER 4, 2004 DETERMINATION, COMPARED TO THE PROPOSED DETERMINATION[1]

Line	Description	2005[2] (Nov. 4, 2004)	2005[3] (Sep. 9, 2004)	Difference
1	*Beginning Balance in Power Charge Accounts*			
2	Operating Account	1,167	1,029	138
3	Priority Contract Account	-	-	-
4	Operating Reserve Account	595	595	-
5	**Total Beginning Balance in Power Charge Accounts**	**1,762**	**1,624**	**138**
6	*Power Charge Accounts Operating Revenues*			
7	Power Charge Revenues from Bundled Customers[4]	3,899	3,925	(26)
8	Extraordinary Receipts[5]	61	45	15
9	Other Revenue[6]	273	202	71
10	Interest Earnings on Fund Balances	26	25	0
11	**Total Power Charge Accounts Operating Revenues**	**4,258**	**4,198**	**60**
12	*Power Charge Accounts Operating Expenses*			
13	Administrative and General Expenses	45	45	-
14	Total Power Costs	4,550	4,419	131
15	Gas Collateral Costs	107	70	37
16	**Total Power Charge Accounts Operating Expenses**	**4,703**	**4,534**	**169**
17	Net Operating Revenues	(444)	(336)	(108)
18	Net Transfers from/(to) Bond Charge Accounts & Adjustments	-	-	-
19	Total Net Revenues	(444)	(336)	(108)
20	**Ending Aggregate Balance in Power Charge Accounts**	**1,317**	**1,288**	**29**

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.	282	317	(35)
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.	564	544	20
Total Operating Reserves:	846	861	(14)

[1]Numbers may not add due to rounding.
[2]As included in the Department's November 4, 2004 Determination.
[3]As reflected in the Proposed Determination (September 9, 2004).
[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 B-2
SUMMARY OF THE DEPARTMENTS 2005 BOND CHARGE REVENUE REQUIREMENTS AND BOND CHARGE ACCOUNTS, AS PUBLISHED IN THE NOVEMBER 4, 2004 DETERMINATION, COMPARED TO THE PROPOSED DETERMINATION[1]

Line	Description	2005[2] (Nov. 4, 2004)	2005[3] (Sep. 9, 2004)	Difference
1	*Beginning Balance in Bond Charge Accounts*			
2	Bond Charge Collection Account	92	107	(15)
3	Bond Charge Payment Account	681	666	15
4	Debt Service Reserve Account	927	927	-
5	**Total Beginning Balance in Bond Charge Accounts**	**1,700**	**1,700**	**0**
6	*Bond Charge Accounts Revenues*			
7	Bond Charge Revenues[4]	925	886	39
8	Interest Earnings on Fund Balances	47	47	0
9	**Total Bond Charge Accounts Revenues**	**972**	**933**	**39**
10	*Bond Charge Accounts Expenses*			
11	Debt Service on Bonds	922	922	-
12	**Total Bond Charge Accounts Expenses**	**922**	**922**	**-**
13	Net Bond Charge Revenues	51	11	39
14	Net Transfers from/(to) Power Charge Accounts & Adjustments	-	-	-
15	Total Net Revenues	51	11	39
16	**Ending Aggregate Balance in Bond Charge Accounts**	**1,751**	**1,711**	**40**

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	76 - 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	351 - 947	335 - 932	
Debt Service Reserve Account: Established as the maximum annual debt service	927	927	

[1]Numbers may not add due to rounding.
[2]As included in the Department's November 4, 2004 Determination.
[3]As reflected in the Proposed Determination (September 9, 2004).
[4]CRS Bond Charge Revenues are included in this amount, whether from Direct Access or other sources, such as Community Choice Aggregation.

THE REVISED 2005 DETERMINATION

On November 4, 2004, the Department published its Determination of Revenue Requirements for the period of January 1, 2005 through and including December 31, 2005 (the "November 4, 2004 Determination") and submitted it to the Commission. The November 4, 2004 Determination was found to be just and reasonable based on an assessment of all comments, the administrative record, AB1X, the Regulations, Bond Indenture requirements and the Rate Agreement.

The Department has reviewed certain matters relating to its November 4, 2004 Determination, including, but not limited to, operating results of the Electric Power Fund (the "Fund") as of December 31, 2004; the El Paso Energy Settlement Agreement; the Williams Energy Marketing & Trading Settlement Agreement; and developments in natural gas markets. The Department has revised its November 4, 2004 Determination under Section 516 of the Regulations to address the following matters:

- Updated actual Electric Power Fund operating results through December 31, 2004;
- El Paso Energy Settlement Agreement;
- Williams Energy Marketing & Trading Settlement Agreement; and
- Natural Gas Price Forecasts and Related Assumptions.

In addition, the Department has revised the methodology employed to model the Bond Charge Payment Account required balance to take into account the difference between the actual historical variable rate component of total debt service and the variable interest rate projection.

These revisions result in a total reduction in this Revised 2005 Determination of $166 million relative to the November 4, 2004 Determination (the cash basis revenue requirement presented in the November 4, 2004 Determination totaled $4.824 billion). This reduction is comprised of two components: a $91 million decrease in the Department's Power Charge Revenue Requirements; and a $75 million decrease in the Department's Bond Charge Revenue Requirements.

The $91 million Power Charge Revenue Requirement reduction primarily results from the net effects of a $92 million reduction in projected power costs (net of a $50 million reduction in projected extraordinary receipts from settlement agreements), a $33 million offset to power costs resulting from projected fuel costs savings in connection with the Williams Natural Gas Purchase Contract, a $56 million reduction in projected gas collateral costs, and a $37 million reduction in projected revenues from surplus energy sales. The reduction in projected power costs largely results from a decreased fuel price forecast for the 2005 Revenue Requirement Period. As noted below in table D-10, the Department's natural gas price forecast has decreased nearly $1.00/MMBtu relative to the fuel price forecast underlying the November 4, 2004 Determination. The reduction in the Department's fuel price forecast, as well as existing unallocated hedging account balances, also contribute to the projected reduction in gas collateral costs for the Revised 2005 Determination.

Projected surplus energy sales revenues have also decreased relative to the November 4, 2004 Determination based on the aggregate effects of reduced surplus sales volume and price projections. Tables B-3 and B-4 (below) summarize these changes between the November 4, 2004 Determination and the Revised 2005 Determination.

The following revisions address only those changes under the subjects noted above:

(1) Preliminary actual operating results have been updated through December 31, 2004. Preliminary actual operating results are reflected in the Department's

beginning account balances for the 2005 Revenue Requirement Period as well as projections underlying this Revised 2005 Determination.

(2) Changes to the assumptions underlying the distribution of proceeds under the settlement agreement between El Paso Energy and the California Parties have been incorporation into this Revised Determination. Based on the inclusion of twelve additional municipal utilities (these parties previously submitted incomplete information related to the Settlement Agreement and did not receive settlement proceeds in the June 2004 Master Settlement Distribution), including the Metropolitan Water District of Southern California and the California State Water Project, in the settlement agreement between El Paso Energy and the California Parties, the Department's projected settlement receipts have been slightly decreased for the 2005 Revenue Requirement Period (the November 4, 2004 Determination projected semiannual cash payments of \$5.5 million under the settlement agreement; this Revised 2005 Determination projects semiannual cash payments of \$5.4 million). In addition, the Department's beginning account balances for the 2005 Revenue Requirement Period have been updated to reflect the receipt of \$2.7 million in settlement proceeds on December 24, 2004.

(3) Projected savings related to the Williams Natural Gas Purchase Contract have been updated based on the Department's revised natural gas price forecast. The resultant savings amount is projected to equal approximately \$33 million and is allocated to SCE and SDG&E based on the percentages identified in CPUC Decision 03-10-016 (SCE - 62% in 2005; SDG&E - 38% in 2005).

(4) The 2005 gas price forecast has been updated using an average of 10 days closing settlement futures prices for Henry Hub prior to and including February 17, 2005. The November 4, 2004 Determination based its gas price forecast on an average of 10 days closing settlement futures prices for Henry Hub prior to and including October 22, 2004.

Average 2005 Gas Prices at Henry Hub	**$ / MMBtu**
November 4, 2004 Determination	$7.35
Revised 2005 Determination	$6.38

Section D includes additional discussion related to the aforementioned changes reflected in this Revised 2005 Determination.

On March 7, 2005, the Department received comments on proposed revisions to the November 4, 2004 Determination from PG&E and SCE. The comments are summarized and the Department's responses are included in Section I of this Revised 2005 Determination. Following a detailed review of comments received by the IOUs, certain changes were incorporated in this Revised 2005 Determination. All other previous assumptions underlying the November 4, 2004 Determination remain unchanged.

Table B-3 summarizes the changes between the November 4, 2004 Determination and this Revised 2005 Determination for the Power Charge revenue requirement and Power Charge Accounts. Table B-4 summarizes the changes between the November 4, 2004 Determination and this Revised 2005 Determination for the Bond Charge revenue requirements and Bond Charge Accounts.

TABLE B-3
SUMMARY OF THE DEPARTMENTS REVISED 2005 POWER CHARGE REVENUE REQUIREMENTS AND POWER CHARGE ACCOUNTS COMPARED TO THE NOVEMBER 4, 2004 DETERMINATION[1]

Line	Description	2005[2]	2005[3] (Nov. 4, 2004)	Difference
1	*Beginning Balance in Power Charge Accounts*			
2	Operating Account	1,128	1,167	(39)
3	Priority Contract Account	63	-	63
4	Operating Reserve Account	595	595	-
5	**Total Beginning Balance in Power Charge Accounts**	**1,786**	**1,762**	**24**
6	*Power Charge Accounts Operating Revenues*			
7	Power Charge Revenues from Bundled Customers[4]	3,808	3,899	(91)
8	Extraordinary Receipts[5]	11	61	(50)
9	Other Revenue[6]	236	273	(37)
10	Interest Earnings on Fund Balances	26	26	1
11	**Total Power Charge Accounts Operating Revenues**	**4,081**	**4,258**	**(177)**
12	*Power Charge Accounts Operating Expenses*			
13	Administrative and General Expenses	45	45	-
14	Total Power Costs	4,458	4,550	(92)
15	Gas Collateral Costs	52	107	(56)
16	Extraordinary Contract Expenses	(33)	-	(33)
17	**Total Power Charge Accounts Operating Expenses**	**4,522**	**4,703**	**(181)**
18	Net Operating Revenues	(441)	(444)	3
19	Net Transfers from/(to) Bond Charge Accounts & Adjustments	-	-	-
20	Total Net Revenues	(441)	(444)	3
21	**Ending Aggregate Balance in Power Charge Accounts**	**1,345**	**1,317**	**27**

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.	275	282	(7)
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.	555	564	(10)
Total Operating Reserves:	829	846	(17)

[1]Numbers may not add due to rounding.
[2]As included herein.
[3]As reflected in the November 4, 2004 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 B-4
SUMMARY OF THE DEPARTMENTS REVISED 2005 BOND CHARGE REVENUE REQUIREMENTS AND BOND CHARGE ACCOUNTS COMPARED TO THE NOVEMBER 4, 2004 DETERMINATION[1]

Line	Description	2005[2]	2005[3] (Nov. 4, 2004)	Difference
1	*Beginning Balance in Bond Charge Accounts*			
2	Bond Charge Collection Account	199	92	107
3	Bond Charge Payment Account	572	681	(110)
4	Debt Service Reserve Account	927	927	0
5	**Total Beginning Balance in Bond Charge Accounts**	**1,698**	**1,700**	**(3)**
6	*Bond Charge Accounts Revenues*			
7	Bond Charge Revenues[4]	850	925	(75)
8	Interest Earnings on Fund Balances	47	47	(0)
9	**Total Bond Charge Accounts Revenues**	**897**	**972**	**(76)**
10	*Bond Charge Accounts Expenses*			
11	Debt Service on Bonds	922	922	-
12	**Total Bond Charge Accounts Expenses**	**922**	**922**	**-**
13	Net Bond Charge Revenues	(25)	51	(76)
14	Net Transfers from/(to) Power Charge Accounts & Adjustments	-	-	-
15	Total Net Revenues	(25)	51	(76)
16	**Ending Aggregate Balance in Bond Charge Accounts**	**1,673**	**1,751**	**(78)**

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	76 - 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	237 - 834	351 - 947	
Debt Service Reserve Account: Established as the maximum annual debt service	927	927	

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

C. THE DEPARTMENT'S REVISED 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 long-term power contracts;

(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) $4.425 billion for long-term power contract purchases to cover the net short requirement of customers; (b) $45 million in administrative and general expenses; (c) $52 million in gas collateral costs; and (d) $(441) million in net changes to Power Charge Accounts (including operating reserves). This projection results in a total revenue need of $4.081 billion.

Funds to meet these costs (in addition to surplus operating reserves) are projected to be provided from (a) $236 million from the Department's share of surplus power sales revenues; (b) $26 million of interest earned on Power Charge Account balances; (c) $11 million of extraordinary receipts resulting from the ongoing benefits of the El Paso settlement; and (d) $3.808 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:
REVISED RETAIL CUSTOMER POWER CHARGE CASH REQUIREMENT

Line	Description	Amounts for Revenue Requirement Period				
		2005 - Q1	2005 - Q2	2005 - Q3	2005 - Q4	Total
1	*Power Charge Accounts Expenses*					-
2	Power Costs	1,150	909	1,222	1,144	4,425
3	Administrative and General Expenses	11	11	11	11	45
4	Gas Collateral Costs	-	6	25	21	52
5	Net Changes to Power Charge Account Balances	(13)	(54)	(253)	(122)	(441)
6	**Total Power Charge Accounts Expenses**	**1,148**	**872**	**1,005**	**1,055**	**4,081**
7	*Power Charge Accounts Revenues*					
8	Extraordinary Receipts	5	-	5	-	11
9	Other Power Sales Revenues	69	45	57	66	236
10	Interest Earnings on Power Charge Account Balances	7	7	7	6	26
11	Total Power Charge Revenue Requirement[1]	1,068	821	937	983	3,808
12	**Total Power Charge Accounts Revenues**	**1,148**	**872**	**1,005**	**1,055**	**4,081**

[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: REVISED RETAIL CUSTOMER BOND CHARGE CASH REQUIREMENT

Line	Description	Amounts for Revenue Requirement Period				
		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	175	(407)	195	12	(25)
4	**Total Bond Charge Accounts Expenses**	**211**	**217**	**231**	**239**	**897**
5	*Bond Charge Accounts Revenues*					
6	Interest Earnings on Bond Charge Account Balances	4	20	4	19	47
7	Retail Customer Bond Charge Revenue Requirement	207	197	227	220	850
8	**Total Bond Charge Accounts Revenues**	**211**	**217**	**231**	**239**	**897**

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) $(25) million for changes to Bond Charge Account balances, resulting in total Bond Charge Account expenses of $897 million.

Funds to meet these requirements are provided from (a) $47 million in interest earned on Bond Charge Account balances, and (b) $850 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 $5.444 billion. Revenues from interest earned and other power sales are $320 million, and net changes in fund balances are $(466) million, resulting in combined customer revenue requirements of $4.658 billion.

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

This Revised 2005 Determination is based on a number of assumptions regarding retail customer load, demand side management and conservation, power supply, natural gas prices, off-system sales, administrative and general expenses as well as other considerations affecting the Department's revenues and expenses.

IOU LOAD FORECASTS

The Department obtained the most recent customer 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).

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. In addition, 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").

Table D-1 presents the major assumptions employed in the IOU forecasts utilized by the Department for the purpose of this Revised 2005 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-1
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.

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-2.

TABLE D-2
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%

HOURLY LOAD SHAPES

The Department's retail revenue requirements are determined, in part, based on projections of hourly energy dispatches from long-term power contracts, as well as other generating resources, including utility-retained generation, required to serve retail customer load. To facilitate its modeling efforts, the Department "shapes" the load forecasts provided by each IOU to account for hourly variations in retail customer demand. The resultant hourly load profile is utilized in the Department's electric market simulation to derive hourly energy dispatches required to serve retail customer load. To construct the hourly load shapes included in its market simulation, 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 a percentage of sales in each hour to annual energy estimates provided by the IOUs.

SELF-GENERATION

Projected self-generation volumes are incorporated in the IOU load forecasts. Self-generation projections within each IOU service territory were determined by the Department based on 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 suspended 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, 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[4].

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 Decision 02-03-055, while accounting for "normal changes in business operations[5]." 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 PG&E and SCE in January 2004, and SDG&E in September 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] See discussion under Direct Access Surcharge Revenues, below.

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

TABLE D-3
DIRECT ACCESS PERCENT OF LOAD[6]

	Percentage of Total Load
Pacific Gas and Electric Company	10.6%
Southern California Edison Company	13.6%
San Diego Gas and Electric Company	17.9%
Statewide	**12.7%**

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, or resides on land that is annexed by, a California municipality that operates its own electric utility. CCA refers to the ability of communities or public entities to aggregate load and procure all or a portion of their power requirements independent of the IOUs. Assembly Bill 117, adopted in 2002, modified the Public Utilities Code to allow local governments "…to elect to combine the loads of its residents, businesses, and municipal facilities in a community-wide electric buyers' program[7]."

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 2006 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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[6] 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.
[7] Public Utilities Code, Section 331.1(a).

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 Revised 2005 Determination, the Department has assumed that this contract will not be renewed or replaced with another, similar contract.

ESTIMATED ENERGY REQUIREMENTS

Each of the aforementioned considerations, including hourly load shape, self-generation, direct access and other departing load are incorporated in the determination of the amount of energy consumed by the retail customers of the Utilities. Those customers are also the customers of the Department.

Table D-4 shows the estimated gigawatt hours of the expected energy requirements of each IOU's customers during 2005.

TABLE D-4
ESTIMATED ENERGY REQUIREMENTS[8]

	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[9]	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	3,743
Energy Requirements After Adjustments	17,165
All Investor Owned Utilities	
Energy Requirements	201,055
Less Direct Access	25,613
Energy Requirements After Adjustments	175,442

[8] All values presented in Table D-5 include transmission and distribution losses.
[9] For each of the three IOUs, these amounts are intended to represent energy requirements that must be met by the electric generating resources of the IOU, power purchases of the IOU or power purchases of the Department under the PLTPCs.

POWER SUPPLY RELATED ASSUMPTIONS

Three types of power supplies needed to meet the requirements of each IOU were considered by the Department in this Revised 2005 Determination: (a) Utility supplied resources; (b) supply from the Department's long-term power contracts; and (c) the residual net short of each IOU.[10]

Table D-5 below shows, for the 2005 Revenue Requirement Period, the estimated energy requirements for the customers of the IOUs, estimated supplies from generation retained by the three IOUs,[11] the resulting net short, the expected supply from the Department's long-term power contracts, off-system energy sales and the residual net short.

TABLE D-5
ESTIMATED NET SHORT ENERGY, SUPPLY FROM THE DEPARTMENT'S LONG-TERM POWER CONTRACTS AND THE DEPARTMENT'S ESTIMATE OF THE RESIDUAL NET SHORT

	Amounts for the Revenue Requirement Period (Gigawatt-Hours)
All Investor Owned Utilities	
Energy Requirements After Adjustments	175,442
Supply from Utility Resources	127,330
Net Short	48,112
Supply from the Department's Long-Term Power Contracts	56,634
Off-System Sales	(15,919)
Residual Net Short (Surplus)	7,398

Table D-6 shows, on a quarterly basis for the 2005 Revenue Requirement Period, estimated net short volumes in gigawatt-hours, supply from the Department's long-term power contracts, and the residual net short.

[10] 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 Determination for the 2005 Revenue Requirement Period.

[11] 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.

TABLE D-6
NET SHORT, SUPPLY FROM THE DEPARTMENT'S 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	10,117	13,591	$ 1,020	(4,263)	$ (208)	788
Q2-2005	9,760	12,627	$ 985	(4,019)	$ (148)	1,153
Q3-2005	14,818	15,887	$ 1,250	(3,680)	$ (191)	2,611
Q4-2005	13,418	14,528	$ 1,094	(3,957)	$ (211)	2,847
Total	48,112	56,634	$ 4,350	(15,919)	$ (757)	7,398

UTILITY SUPPLIED RESOURCES

The Department reviewed each utility's 2005 forecast of utility owned generation, qualifying facility ("QF") contract generation, and bilateral contract generation for consistency with the Department's own energy dispatch forecast. Where necessary, the Department updated its assumptions concerning QF contract terms and expiration dates, outage schedules, and net dependable resource capacity, amongst others, to reflect current details related to each IOU's resource portfolio.

HYDRO CONDITION ASSUMPTIONS

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

CONTRACT ASSUMPTIONS

During the 2005 Revenue Requirement Period, approximately 57,000 GWhs of energy is projected to be supplied to retail electric customers of the IOUs through the Department's long-term power contracts. The terms and conditions of each contract have been reflected in the Department's market simulation, resulting in a projection of contract-specific, hourly energy dispatches to meet the projected energy requirements of each Utility's retail customers. The terms and conditions incorporated in the Department's market simulation include, among other details, must-take energy volumes and dispatchable contract capacities, contract heat rates and unit outage rates as well as scheduling limitations. During market simulation, all energy dispatches from the Department's dispatchable long-term power contracts are executed based on economic considerations to achieve the lowest possible total cost of power. In general, each incremental generating unit is dispatched only if the cost of generating an additional MWh from that unit is less than the cost of market clearing prices.

Table D-7 provides a listing of all of the long-term power contracts that will be operational during the 2005 Revenue Requirement Period and beyond, describing the term and capacity associated with each contract and the IOU to which the contract has been allocated. This list includes a contract with the Kings River Conservation District which the Department signed in December 2002 relative to approximately 90 MW of capacity for 10 years, currently expected to begin in June 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 are $16.9 million, reflecting decreases in both the price and the projected amount of Monthly Nominated Capacity. Detailed contract terms can be found on the CERS website, http://cers.water.ca.gov.

TABLE D-7
LONG-TERM POWER 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
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 7/2/04	Upon COD, est. 1/07	12/31/2012	25 to 30	PG&E
Coral Power, LLC	5/24/2001	1/1/2004	12/31/2005	400	PG&E

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
"	"	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
Kings River Conservation District	12/31/2002 Renegotiated 8/18/04	Upon COD, est. 6/2005	Est. 5/31/2015	Est. 92	Est. PG&E
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
City/County of San Francisco	12/30/2002	Upon COD, est. 4/2006	Est. 3/31/2016	Est. 180	Est. PG&E
Sempra Energy Resources	5/4/2001	1/1/2004	9/30/2011	1200; drops to 800 in Mar-May of 2004-2007	SCE
"	"	1/1/2004	9/30/2011	700; drops to 400 in Mar-May of 2004-2007, and permanently starting Jan 2008	SCE

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Allocated
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

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 power 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. Three of the remaining contracts have yet to be renegotiated from their original terms.

CONTRACT MANAGEMENT AND DISPOSITION ALTERNATIVES

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

The Department has renegotiated 22 of the remaining original contracts entered into in 2001 and has terminated five additional contracts for cause. 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 power 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.

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.

SALES OF EXCESS ENERGY ASSUMPTIONS

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

On September 19, 2002, the Commission issued Decision 02-09-053, Interim Opinion on Procurement Issues: DWR Contract Allocation. This Decision allocated each of the thirty-five long-term power contracts to a specific IOU. Decision 02-09-053 also determined that income from the sale of excess energy ("off-system sales") would be shared on a pro-rata basis between the Department and the IOUs.

Projected revenue shares from the sale of excess energy, both the Department's and total IOU, are provided in Table D-8 below.

TABLE D-8
PROJECTED SALE OF EXCESS ENERGY

	DWR Volume (GWh)	IOU Volume (GWh)	Total Volume (GWh)	DWR Revenue[1] (Millions of Dollars)	IOU Revenue[1] (Millions of Dollars)	Total Revenue[1] (Millions of Dollars)	Weighted Average Price ($/MWh)
Q1-2005	1,208	3,055	4,263	$ 60	$ 147	$ 208	$ 49
Q2-2005	1,025	2,995	4,019	$ 39	$ 109	$ 148	$ 37
Q3-2005	1,244	2,436	3,680	$ 70	$ 121	$ 191	$ 52
Q4-2005	1,199	2,759	3,957	$ 65	$ 146	$ 211	$ 53
Total	4,675	11,244	15,919	$ 234	$ 523	$ 757	$ 48

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

LONG-TERM POWER CONTRACT COST ASSUMPTIONS

Each long-term power contract identified in Table D-7 has been reviewed by the Department to determine the costs that will impact its revenue requirements during 2005. All applicable costs are reflected in the Department's electric market simulation along with previously noted operational considerations. The types of costs included in the Department's contract-specific projections include, but are not limited to, fixed energy, capacity, fixed operation and maintenance, variable operation and maintenance, scheduling coordinator fees, and fuel management fees. Total accrued long-term power contract costs, including requisite natural gas purchases, are projected to be $4.350 billion for the 2005 Revenue Requirement Period, as noted in Table D-6. Natural gas costs represent a significant component of the Department's total energy costs and are discussed below in greater detail.

For informational purposes, Table D-9 shows, for the 2005 Revenue Requirement Period, the expected average cost (in $/MWh) on a quarterly basis for the Department's long-term power contracts.

TABLE D-9
ESTIMATED POWER SUPPLY COSTS
(Dollars per Megawatt-Hour)

	Long-Term Power Contracts
Quarter 1 – 2005	$75
Quarter 2 – 2005	$78
Quarter 3 – 2005	$79
Quarter 4 – 2005	$75

NATURAL GAS PRICE FORECAST AND FUELS ASSUMPTIONS

The natural gas price forecast supporting this Revised 2005 Determination is an update of the gas price forecast used in the November 4, 2004 Determination. The update was prepared by DWR and its advisors in February 2005. This forecast reflects a decrease to the 2005 price forecast when compared to the price forecast supporting the November 4, 2004 Determination.

A comparison of the year-over-year Henry Hub prices forecast in the November 4, 2004 Determination and the update used in this Revised 2005 Determination is shown in Table D-10.

TABLE D-10
NATURAL GAS PRICE FORECAST COMPARISON AT HENRY HUB
(Nominal $/MMBtu)

	2005	**2006**	**2007**
Gas Price Forecast Revised Determination	$6.38	$5.75	$5.54
Gas Price Forecast November 4, 2004	$7.35	$6.22	$5.77
Difference	$(0.97)	$(0.47)	$(0.23)

The gas price forecast was prepared by using a proprietary econometric Long-Term Price Model, the same model used in all prior revenue requirement determinations. This model forecasts prices for Henry Hub and then uses regression analyses between Henry Hub and several other pricing points, including PG&E Citygate and the Southern California Border, to arrive at prices for these locations. The February 2005 forecast updates the Henry Hub base forecast using actual wellhead gas prices through December 2004, and updated data for well completions and weather-adjusted storage variables. To forecast monthly prices at Henry Hub for 2005, a 10-day average of settlement prices for NYMEX contracts for March through December 2005 were combined with published historical monthly index prices for January and February 2005, with the resultant annual average price for 2005 price distributed across the 12 months using historical spread factors. The period for the 10-day average NYMEX prices included daily settlements up to and including February 17, 2005. 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 February 2005 price forecast at two key pricing hub locations: PG&E Citygate 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	$6.45	$5.88	$6.71	$6.11
February	$5.51	$5.02	$5.73	$5.22
March	$5.32	$4.85	$5.53	$5.04
April	$5.62	$5.12	$5.84	$5.32
May	$5.94	$5.42	$6.18	$5.63
June	$6.01	$5.47	$6.24	$5.69
July	$5.87	$5.35	$6.10	$5.56
August	$5.46	$4.97	$5.67	$5.17
September	$5.62	$5.12	$5.84	$5.32
October	$5.77	$5.26	$6.00	$5.46
November	$6.18	$5.64	$6.43	$5.86
December	$6.11	$5.57	$6.35	$5.79
Annual Average	**$5.82**	**$5.31**	**$6.05**	**$5.51**

For the purposes of this Revised 2005 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 revenue requirement determinations prior to the November 4, 2004 Determination, gas prices were forecast to major gas price hub locations only, such as the Southern California Border, the PG&E Citygate and others such as the Rockies and AECO "C" in Alberta. This method may have resulted in an understatement of total delivered gas costs.

The purpose of including transportation costs downstream of the hub locations is to accurately align forecasted fuel costs with actual fuel costs at the plant level. The current price forecast does not incorporate transportation rates in the PG&E service territory as a result of the Gas Accord III decision in December 2004, which reduced backbone rates from Malin and increased rates for transport from Topock.

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.

GAS COLLATERAL COSTS

For the 2005 Revenue Requirement Period, the Department has identified, as a separate line item, cash collateral provided in connection with gas purchases. These funds are to enable the hedging decisions of the IOUs in connection with the operation of the Department's power contracts. 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 futures contract and also, separately, upon fixed prices per basis contract. In order to determine 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 Revised 2005 Determination. Based upon these volumes, margin requirements to purchase futures for the fuels program from June through December 2005 would be $83 million. This amount is 22% lower than the 2005 collateral requirement of $107 million included in the November 4, 2004 Determination. The decrease in margin requirements is due primarily as a result of decreased NYMEX contract margin costs, which reflect decreased natural gas prices and volatility in the natural gas market, and the exclusion of gas volumes provided by Williams via a negotiated fixed contract price.

While the Department's collateral requirement for 2005 is determined to be $83 million, the hedging account held by the Department with A.G. Edwards contained $31 million that was not allocated to any investment or IOU sub-account as of December 31, 2004. The amount required for 2005 ($83 million), therefore, is decreased by the amount currently held in the account ($31 million), meaning that $52 million is required from this Revised 2005 Determination.

The IOUs have supplied DWR with copies of data request responses sent to the CPUC related to the gas collateral costs identified in the November 4, 2004 Determination. These data request responses have been included in the administrative record supporting this Revised 2005 Determination but have been designated as confidential. The IOUs have also supplied recent Gas Supply Plans, which were reviewed in the development of the Department's collateral costs. These materials have also been designated as confidential. Since the November 4, 2004 Determination was submitted, short-term gas prices have fallen significantly and the Department has adjusted gas prices accordingly, resulting in the use of gas prices that are even lower than those suggested by at least one IOU in its data request response to the CPUC.

As noted above, the Department uses the anticipated gas requirements for a seven-month period based on the production simulation analysis that supports this Revised 2005

Determination. Another methodology may be to use the ratable rate volume provided in the IOUs' Gas Supply Plans for the DWR Long-Term Contracts. Ratable rate volumes are determined in order to identify maximum forward physical purchases of gas to meet requirements for the Long-Term Contracts. Because the gas collateral cost is intended to reflect the potential cost of placing financial hedges for the gas supply required for the Long-Term Contracts, the Department does not believe that the use of ratable rate volumes identified for forward physical purchases is appropriate. Financial hedges can be placed on all volumes at any time, and maintaining an adequate collateral balance allows the Department and the IOUs to maintain the flexibility necessary to hedge against increasing gas costs.

In the confidential response to the CPUC's data request, another IOU suggested that it intended to request that financial hedges be placed on a significantly smaller amount of gas requirements than the full hedge assumption made by DWR in the November 4, 2004 Determination and that much of that hedging would be performed through the use of less-expensive option hedges. The Department agrees that all of the IOUs should have this flexibility, but DWR believes that providing adequate financial backing for such flexibility requires collateral in the amount determined by the Department in this Revised 2005 Determination.

The Department has reviewed and corrected specific errors identified by another IOU in its response to the CPUC's data request. These errors related to the determination of an initial margin requirement for a specific DWR contract and the size, and subsequent number, of the basis contracts used to calculate the cost of collateral. The errors, while minor, have been corrected in this Revised 2005 Determination.

Finally, in response to the CPUC's data request, one of the IOUs' suggested a different method of determining the cost of collateral: The Department should finance the collateral requirement rather than hold the full amount of money that is collected from ratepayers. This method, or so the IOU contends, would decrease the cost to ratepayers from the full collateral cost to the cost of carrying the collateral cost, either through interest on borrowing or through the cost of a letter of credit. The Department is currently considering this alternative and welcomes additional suggested methods to decrease costs to ratepayers. It is worth noting, however, that ultimately, when the Department no longer needs to hold collateral for gas hedging, the amount held in the hedging account will be returned to ratepayers. As such, the actual cost to ratepayers of the method currently employed by the Department is the cost of carrying the collateral requirement, not the full collateral requirement. The "financing" of this collateral is simply done internally, rather than externally through a financial institution. Also, in either method, hedging costs will be incurred. To the extent that those costs were covered by funds that were externally financed as a collateral requirement, additional financing would need to be undertaken to replenish the collateral requirement.

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 combination 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, on December 24, 2004 the Department received a cash payment of $2.7 million from El Paso Energy (this amount was $2.7 million less than expected and resulted from disbursements to twelve additional municipal utilities, including the Metropolitan Water District of Southern California and the California State Water Project, in the November 2004 Master Settlement Distribution; these twelve municipal utilities did not receive funds in the June 2004 Settlement Distribution due to incomplete information submittals). This payment was the first in a series of semiannual cash payments that were scheduled to begin in July 2004 as deferred consideration from El Paso Energy. The $2.7 million settlement receipt is reflected in the beginning account balances for the 2005 Revenue Requirement Period.

Semiannual cash payments are to be made in the amount of $5.4 million and will be paid by El Paso Energy to the Department each January and July for the next 20 years (39 payments of $5.4 million, totaling approximately $209 million over 20 years), ending with a final payment in January of 2024. The payment scheduled for receipt in January 2005 remains in escrow, pending the resolution of additional settlement-specific details. For the purposes of this Revised 2005 Determination, the Department is projecting receipt of the January 2005 scheduled payment during the month of March 2005.

Due to the inclusion of twelve additional municipal utilities in this Settlement Agreement, projected semiannual payments were slightly decreased in relation to amounts noted in the November 4, 2004 Determination ($5.5 million/semiannual – November 4, 2004 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). On October 2, 2003, the CPUC issued Decision 03-10-016, which allocated fuel volumes related to the Williams Natural Gas Purchase Contract between SCE (62% in 2005) and SDG&E (38% in 2005).

During the 2005 Revenue Requirement Period, it is projected that the Natural Gas Purchase Contract will result in power cost savings of approximately $33 million, based on the difference between the contract fuel price of $3.85 and the Department's projected average annual fuel price of $5.82. This projected benefit has been allocated to SCE and SDG&E in the ratio reflected in Decision 03-10-016.

DYNEGY POWER MARKETING SETTLEMENT AGREEMENT

On October 25, 2004, the Federal Energy Regulatory Commission ("FERC") approved a Settlement filed on June 28, 2004 by the Dynegy Parties and the California Parties, which include among others, the Department and the IOUs, and the California Public Utilities Commission.[12] The FERC filing consists of a Joint Offer of Settlement, a Joint Explanatory Statement, and a Settlement and Release of Claims Agreement. In the Joint Explanatory Statement, Section II, E, it is noted that Dynegy will provide approximately $281.5 million in refunds as part of the Settlement. The specific disbursement of these funds is outlined in Exhibit A, the Allocation Matrix, of the Settlement and Release of Claims Agreement.

The refund amounts identified in the Allocation Matrix are adjusted, pursuant to the Joint Explanatory Statement, for gas and emissions allowances, resulting in a net settlement amount of $216 million. Based on settlement terms, the Department was scheduled to receive approximately $119.7 million, as well as an additional $3.6 million related to Out of Market energy purchases transacted by the Department between January 17, 2001 and June 20, 2001.

The Department received $98.7 million of the aforementioned funds on November 22, 2004. The settlement proceeds have been considered in this Revised 2005 Determination and differ slightly from the amount of scheduled receipts, as the Settlement, Section 5.2.4.1, specifies that $22 million of the amount payable to CERS (approximately $123.3 million, including the amount of $3.6 million related to Out of Market purchases) will be retained in the Dynegy Refund Escrow (or another escrow specified by the Department) to pay any claims against the Department (retention of the $22 million is specifically addressed in Section 5.1.4.2 of the Settlement). The amount of $3.6 million related to Out of Market energy purchases has not yet been received by the Department. The settlement receipt of $98.7 million increased the Department's beginning account balances for the 2005 Revenue Requirement Period.

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

[12] 109 FERC 61,071

Department for 2001 power purchases and interest that had accrued on the General Fund advances, and (c) fund reserves required to complete the bond financing.

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

For purposes of calculating the interest earnings on all account balances, the Department assumes a 4.0 percent rate for the Debt Service Reserve Account (reflecting the Department's new investment agreements) 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 $850 million.

ACCOUNTS AND FLOW OF FUNDS UNDER THE BOND INDENTURE

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

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

The MOEAB is to be determined by the Department at the time of each revenue requirement determination and, when the Department is not procuring the residual net short, is to be an amount equal to the largest projected difference between the Department's projected operating expenses and the Department's projected Power Charge revenues during any one month period during the revenue requirement period, taking into account a range of possible future outcomes (i.e., "stress cases").

For the purposes of this Revised 2005 Determination, the MOEAB is determined to be $275 million. The Department projects to exceed the MOEAB at all times during 2005. The Department has determined that the amount projected to be on deposit in the Operating Account, including the amount therein that acts as a reserve for Operating Expenses, is just and reasonable, based in part on the following: (1) potential gas price volatility, (2) potential gas price escalation, (3) year-over-year revenue requirement volatility, and (4) credit rating agency and credit and liquidity facility considerations, as well as the factors discussed below under "Sensitivity Analysis" and in Section E—"Key Uncertainties in the Revenue Requirement Determination".

PRIORITY CONTRACT ACCOUNT

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

For the 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 are to be based on such assumptions as the Department deems to be appropriate after consultation with the Commission and, in the case of clause (i) above, may take into account a range of possible future outcomes (i.e., "stress cases").

Based on the "stress" operating conditions (later described in the "Sensitivity Analysis" portion of Section D), the ORAR for the 2005 Revenue Requirement Period is determined by the Department to be $555 million, reflecting an amount equal to 12 percent of the Department's annual eligible Operating Expenses for the period of January 2004 through December 2004. In accordance with the Indenture, the ORAR reflects adjustments in annual Operating Expenses for the period of January 2004 through December 2004 to account for expenses associated with Power Supply Contracts that are no longer the Department's financial responsibility (i.e. the Dynegy Power Marketing Power Supply Contract, which expired on December 31, 2004).

BOND CHARGE COLLECTION ACCOUNT

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

The minimum balance to be maintained from time to time within the Bond Charge Collection Account is determined to be an amount equal to one month's required deposit to the Bond Charge Payment Account. As required by the Bond Indenture, the Department assumes interest costs on unhedged Variable Rate Bonds during the 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 $237 to $834 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 any necessary revised Retail Revenue Requirement proceeding, it expects no more than seven months will elapse before it receives modified levels of revenues associated with the filing. As explained in prior Department revenue requirement determinations, during this seven month period the Department would endeavor to identify any material changes in its revenue requirement, proceed through its own administrative determination of its modified revenue requirement, 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 Revised 2005 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.[13]. 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.

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

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.

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 Revised 2005 Determination. Several risk factors are outlined below and additional information may be found in each of the bond financing Official Statements, which may be obtained from the Treasurer of the State of California.

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

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

3. Certain risks associated with DWR's Power Supply Program:
   a. Long-term power contracts:
      i. Impact of renegotiated contracts;
      ii. Off-system sales volume and price variability; and
      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.

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; and
   g. Actions affecting retail rates.

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

6. Potential variance in dispatch of DWR contracts:
   a. Actual vs. forecast load variance; and
   b. 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; and
    c. Possible Federal legislation or action.

F. JUST AND REASONABLE DETERMINATION

This section explains the Department's reasons for determining that this Revised 2005 Determination is just and reasonable, and the process leading to the rendering of this Revised 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 were a discussion of the just and reasonable standard, 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 entered into by the Department, including the existing market conditions, the portfolio planning process, the procurement activities and the negotiating environment as well as other factors leading to the Determination. That information is, to the extent applicable and not modified herein, incorporated in this Revised 2005 Determination by reference and will not be repeated herein. The material referenced is included in the administrative record of this Revised 2005 Revenue Requirement. For further information please refer to Section J. 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 Revised 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 Revised 2005 Determination by reference and will not be repeated herein. The material referenced is included in the administrative record of this Revised 2005 Revenue Requirement. For further information please refer to Section J.

THE 2004 DETERMINATION

The 2004 Determination was published on September 18, 2003. The 2004 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 entered into by the Department, 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 Revised 2005 Determination by reference and will not be repeated herein. The material referenced is included in the administrative record of this Revised 2005 Revenue Requirement. For further information please refer to Section J.

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 Revised 2005 Determination by reference and will not be repeated herein. The material referenced is included in the administrative record of this Revised 2005 Revenue Requirement. For further information please refer to Section J.

THE NOVEMBER 4, 2004 DETERMINATION

The original 2005 Determination was published on November 4, 2004. The November 4, 2004 Determination provided extensive material leading to the determination by the Department that its revenue requirement for 2005 as determined therein was just and reasonable. In finding the November 4, 2004 Determination to be just and reasonable, the Department discussed the long-term power purchase contracts entered into by the Department, 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 Revised 2005 Determination. The material referenced is included in the administrative record of this Revised 2005 Revenue Requirement. For further information please refer to Section J.

THE REVISED 2005 DETERMINATION – DEVELOPMENT OF THE DETERMINATION

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 and Departing Load information, retained generation, including bilateral contracts, QF information and owned generation. The Department also provided lists of its long-term power contracts, as 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. 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 IOU as confidential and provided under non-disclosure agreements, became the basis of the Department's analytical and forecasting efforts related to the development of this Revised 2005 Determination. The Department also considered other important criteria such as Commission Decisions and Bond Indenture requirements. The resulting data was incorporated in the PROSYM market simulation and the Department's Financial Model, and became a part of the projections underlying the November 4, 2004 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 the November 4, 2004 Determination. The Department provided each IOU with the opportunity to provide input with respect to the assumptions utilized in the November 4, 2004 Determination.

In this Revised 2005 Determination the vast majority of assumptions underlying the November 4, 2004 Determination remain unchanged. However, there were certain assumptions and available data that, when considered herein, provide a considerable benefit to California's ratepayers. These changes are discussed in detail within Section B of this Revised 2005 Determination and result in a total revenue requirement reduction of $166 million relative to the November 4, 2004 Determination (the cash basis revenue requirement presented in the November 4, 2004 Determination totaled $4.824 billion).

The long-term power contracts contained in this Revised 2005 Determination were reviewed extensively in the 2003 Determination, with updates for renegotiation efforts reviewed in the 2003 Supplemental Determination, the 2004 Determination, the 2004 Supplemental Determination and the November 4, 2004 Determination. This Revised 2005 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 Revised 2005 Determination is included in Section D.

PUBLIC PROCESS

On September 9, 2004, the Department noticed and published its Proposed Determination of Revenue Requirements for the Period January 1, 2005, through December 31, 2005 and invited public review and comment related thereto. Interested persons were advised to submit comments on September 30, 2004. The Department provided interested persons with quantitative results from its PROSYM market simulation and Financial Model, subject to applicable non-disclosure requirements.

During the comment period, the Department received questions from PG&E and from SCE. The questions are included in Section J of this Revised 2005 Determination. In response to the questions, and to assist interested persons in their review of this Revised 2005 Determination, the Department conducted conference calls with PG&E and with SCE, assisting these interested persons in locating data contained in the administrative record, and, when appropriate, providing clarification.

On September 30, 2004, the Department received comments from PG&E, SCE and SDG&E. No other persons submitted comments at that time. The Department has reviewed and considered each comment. The comments and the Department's responses are reviewed in Section H of this Revised 2005 Determination. The complete comments are included in the administrative record and are referenced in Section J.

As a result of the comments received and further analysis undertaken by the Department, DWR identified additional material to be included in the record and determined that changes were required in the November 4, 2004 Determination.

On October 20, 2004, the Department issued a "Notice of Additional Material To Be Relied upon in Determination of a Revenue Requirement". This Notice included new or updated information regarding the Clearwood contract, the Kings River Conservation District contract, and SCE's resource forecast. The Notice provided interested persons with the opportunity to submit comments up to and including October 27, 2004.

On October 27, 2004, the Department received additional comments from SCE and PG&E. These comments are summarized in Section H, along with the Department's response. Copies of SCE and PG&E's comments are included in the administrative record supporting this Revised 2005 Determination.

On October 29, 2004, the Department received a letter from Mr. Paul Clanon, Director of the Commission's Energy Division, providing comments in response to the Notice of Additional Material. The Department has summarized these comments in Section H, along with related responses. A copy of Mr. Clanon's letter is included in the administrative record supporting this Revised 2005 Determination.

On November 4, 2004, the Department published its Determination of Revenue Requirements for the period of January 1, 2005 through and including December 31, 2005 and submitted it to the Commission. The November 4, 2004 Determination was found to be just and reasonable based on an assessment of all comments, the administrative record, AB1X, the Regulations, Bond Indenture requirements and the Rate Agreement.

Following its submission of the November 4, 2004 Determination, the Department reviewed certain matters relating to its November 4, 2004 Determination, including, but not limited to, operating results of the Electric Power Fund (the "Fund") as of December 31, 2004; the El Paso Energy Settlement Agreement; the Williams Energy Marketing & Trading Settlement Agreement; and developments in natural gas markets. The Department believed that certain revision to its November 4, 2004 Determination would benefit retail rate payers in the IOUs' service territories and on February 28, 2005, the Department published its Revision to 2005 Revenue Requirement Determination and submitted it to the Commission.

On March 7, 2005, the Department received comments from PG&E and SCE. No other persons submitted comments at that time. The Department has reviewed and considered each comment. The comments and the Department's responses are reviewed in Section I of this Revised 2005 Determination. The complete comments are included in the administrative record and are referenced in Section J. The aforementioned issues addressed in this Revised 2005 Determination are discussed in detail within Section D. All other assumptions underlying the November 4, 2004 Determination remain unchanged in this Revised 2005 Determination.

JUST AND REASONABLE DETERMINATION

After assessing all comments, the administrative record, AB1X, the Regulations, Bond Indenture requirements and the Rate Agreement, the Department has found this Revised Determination of Revenue Requirements for the 2005 Revenue Requirement Period to be just and reasonable.

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 Revised 2005 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 Revised 2005 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)

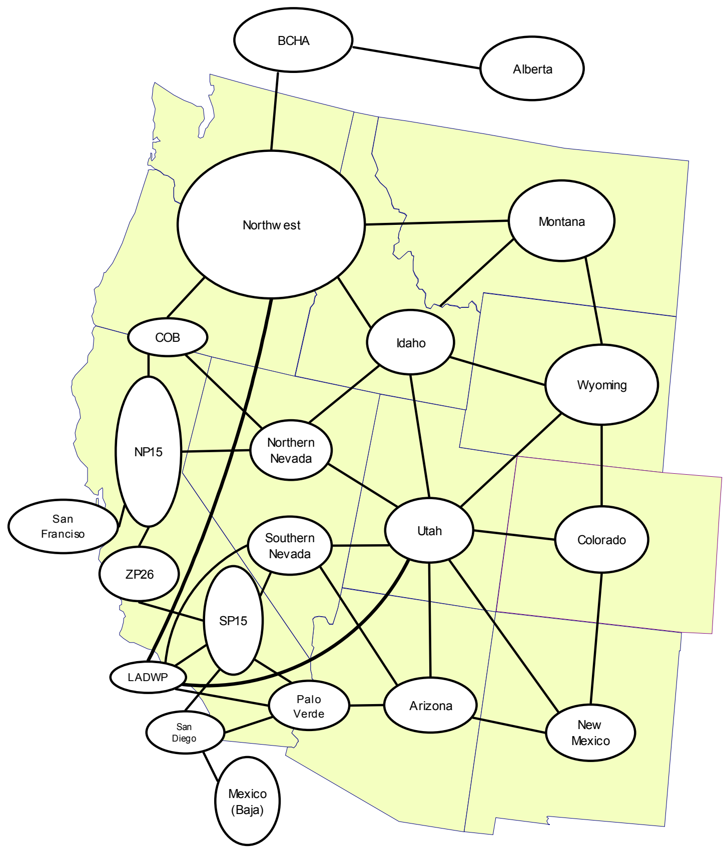
	Incremental	Price Markup	Peak Period Bidding	Total
California	68%	28%	4%	100%
Non-California	80%	14%	6%	100%
Total WECC	75%	20%	5%	100%

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. Copies of the Department's long-term power contracts are included in the administrative record supporting this Revised 2005 Determination.

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 Revised 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 Revised 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 year.s
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. COMMENTS RECEIVED ON THE PROPOSED DETERMINATION AND THE DEPARTMENT'S RESPONSE

On September 30, 2004, PG&E, SCE and SDG&E provided comments on the Department's Proposed Determination published on September 9, 2004. No other persons provided comments at that time.

The Department has reviewed and considered all comments received. The comments are summarized below, and the Department's responses are also provided.

Comments of Pacific Gas & Electric on the Department of Water Resources' Proposed Determination of Revenue Requirements for the Period January 1, 2005 through December 31, 2005

(1) PG&E argues that the Department should use the 2005 revenue requirement as an opportunity to engage in open and reasoned decision-making regarding whether its costs, revenue requirements and actions for 2005 are reasonable, prudent and in the public interest. In addition, PG&E recommends that, after taking into account all public comments received in this proceeding, the Department should issue and submit a new "Just and Reasonable Determination of Revenue Requirements" for 2005.

Response: The Department initiated the 2005 development process in 2003, by soliciting input from the IOUs. The development process has been iterative and has included substantial participation by PG&E and the other IOUs. The Department has reviewed and considered all comments provided during the process of developing the 2005 revenue requirement, including the consideration of comments noted within this section. As a result of this review and the administrative process undertaken pursuant to the Regulations, the Department has determined that its Revenue Requirements for 2005, as set forth herein, are just and reasonable.

(2) PG&E requests that the Department consider as part of its 2005 Determination, PG&E's prior comments related to filings in 2001, 2002, 2003 and 2004 and PG&E's submittals to the Sacramento Superior Court.

Response: All comments referenced by PG&E are part of the Department's administrative record, and on a cumulative basis have been considered and addressed in prior proceedings.

(3) In its comments, PG&E indicates that there remain several DWR long-term contracts with above-market costs, whose suppliers have resisted the Department's efforts to renegotiate.

Response: The Department appreciates PG&E's comment and is continuing in its efforts to renegotiate various contracts.

(4) PG&E comments that the Department must provide further support and justification for its costs, or reduce its "2004" revenue requirements.

Response: The 2004 revenue requirement has been addressed in prior determinations made by the Department.

(5) PG&E argues that the Clearwood Project should be removed as a DWR resource for purposes of the 2005 Determination, indicating the assumed operational date of July 1, 2005, is based on old data.

Response: The Department has reviewed the status of the Clearwood Project and agrees that the 2005 Determination should reflect the renegotiated terms of the Clearwood contract. This Determination reflects the renegotiated terms as modeled in PROSYM.

(6) PG&E argues that the King's River Project should not be included in the 2005 Determination until DWR completes a full reasonableness review of its contractual arrangements.

Response: The Department has reviewed the status of the King's River Conservation District power purchase contract. Updated information was identified for interested parties in the "Notice of Additional Material" issued on October 20, 2004. This 2005 Determination finds the projected costs associated with the Kings River Conservation District power purchase contract to be just and reasonable.

(7) PG&E comments that DWR has allocated the King's River contract to PG&E for operational purposes. A decision by the CPUC allocating this contract to PG&E is needed and PG&E is ready to work with DWR to obtain such a decision.

Response: This Determination assumes that this contract will be allocated to PG&E based on geographical and other considerations, including applicable rulings issued by the California Public Utilities Commission. DWR intends to support the CPUC in any allocation decision related hereto.

(8) PG&E states that the CPUC's 2005 Revenue Requirement Proceeding should address issues associated with the true-up of DWR's 2003 PCRR.

Response: The Department intends to provide 2003 operating data to the CPUC, the IOUs and other interested persons in connection with the CPUC's revenue requirement allocation proceedings.

(9) PG&E requests that the CPUC and the Department begin necessary preparatory work to establish utility-specific balancing accounts.

Response: The Department continues to maintain its tracking of utility-specific projected and actual Bond Charge and Power Charge revenues, off-system sales revenues, power costs, and Power Charge and Bond Charge fund transactions. The Department intends to assist the CPUC and the IOUs in developing utility-specific balancing accounts upon the adoption of a decision by the CPUC addressing a permanent allocation methodology for

DWR's revenue requirements. After DWR implements utility-specific balancing accounts, DWR will continue to develop its revenue requirements based on Power Charge and Bond Charge account balance requirements rather than utility-specific operating results.

(10) PG&E argues that the CPUC's annual allocation proceedings should be used as the procedural vehicle to determine DA and DL cost responsibility, and should be the subject of a procedural ruling by the assigned ALJ.

Response: The Department defers to the CPUC concerning the appropriate process to determine DA and DL cost responsibility.

Comments of Southern California Edison on the Department of Water Resources' Proposed Determination of Revenue Requirements for the Period January 1, 2005 through December 31, 2005

(1) SCE comments that the Department's estimate of sales of excess energy in the amount of $202 million during 2005 is significantly understated.

Response: The Department has determined that the changes proposed by SCE are appropriate to DWR's surplus sales projections. These changes have been incorporated in this Determination.

(2) SCE argues that the Department has not included its forecasted 2005 production from SCE's Spring 2004 Capacity Solicitation or anticipated 2005 Proxy Capacity Solicitation. In June 2004, SCE signed a number of contracts that will facilitate its ability to meet total peak capacity in the third quarter of 2005. SCE has included a proxy capacity contract or call-option contract in its 2005 ERRA forecast that will be solicited during the spring of 2005 and available for dispatch on July 1, 2005 to meet 2005 summer needs, as well as 2006 capacity needs, including resource adequacy demonstrations.

Response: The Department agrees that new and updated information should be included in this Determination. The Department requested, and SCE provided, the necessary detailed information to allow the Department to update this Determination. The Department provided its "Notice of Additional Material" on October 20, 2004, which included this confidential information provided by SCE.

Comments of San Diego Gas & Electric on the Department of Water Resources' Proposed Determination of Revenue Requirements for the Period January 1, 2005 through December 31, 2005

(1) SDG&E comments that the Direct Access Percent of Load in the Determination is listed as 16.5%. SDG&E states the Direct Access Percent of Load, as reported to the CPUC in early 2004 was 17.9%, and SDG&E recommends the Department should use 17.9% as the percentage of load in SDG&E's service territory receiving Direct Access.

Response: The Department agrees that new and updated information should be included in this Determination. The Department has included the updated direct access percent of load in its electric market simulation supporting this Determination. Changes to the load shape in SDG&E's service area affect the timing of Bond Charge revenue receipts. This change results in an increase to the Bond Charge Revenue Requirement for the 2005 Revenue Requirement Period and a corresponding decrease in 2006.

(2) SDG&E comments on the Williams Energy Marketing & Trading Settlement Agreement for natural gas, and the savings or revenue of $34 million. SDG&E indicates the amount should be allocated to SCE and SDG&E in proportion to the CPUC's allocation of the volumes of gas to SCE and SDG&E, and not treated as a common pool of savings or revenues.

Response: The Department has provided the gas savings information related to the Williams Settlement in this Determination. This information is intended to assist the CPUC in its allocation decisions.

On October 20, 2004 the Department provided "Notice of Additional Material" and extended the date for comments.

On October 27, 2004 additional comments were received from PG&E and SCE, these comments are summarized below and the Department's responses are provided.

Supplemental comments of PG&E on the Department of Water Resources' Proposed Determination of Revenue Requirements for the Period January 1, 2005 through December 31, 2005

(1) PG&E requests that DWR conduct a full and open process, with participation of the public, to determine whether the Kings River Conservation District (KRCD) contract was consummated using a competitive process to assure the most favorable terms for the customers of investor-owned utilities.

Response: The Department has provided information concerning the KRCD contract and provided interested persons with the opportunity to comment. Based on the information in the administrative record, the Department has determined that the costs of the KRCD contract included within this Determination are just and reasonable.

(2) PG&E comments that it envisions that customers of all three utilities would bear the burden of any 'above market' costs associated with the allocation of the KRCD Power Purchase Agreement. PG&E recognizes that the CPUC, not DWR, allocates the costs of DWR contracts.

Response: The Department appreciates that PG&E recognizes the CPUC's role in the revenue requirement allocation process and that DWR is not responsible for the allocation of contract costs.

(3) PG&E reiterates its comments previously submitted on September 30, 2004: "If DWR expects PG&E to assume operational dispatch of the [KRCD project] …, it needs to obtain a decision from the CPUC allocating the contract to PG&E ….".

Response: This Determination assumes that this contract will be allocated to PG&E based on geographical and other considerations, including applicable rulings issued by the California Public Utilities Commission. DWR intends to support the CPUC in any allocation decision related hereto.

(4) PG&E states its willingness to assist in assuming operational dispatch is linked to the CPUC also allocating the above market costs of such contract fairly among customers of the State's three utilities.

Response: The allocation of contract dispatch responsibilities and the allocation of related contract costs are the responsibility of the CPUC.

Supplemental comments of SCE on the Department of Water Resources' Proposed Determination of Revenue Requirements for the Period January 1, 2005 through December 31, 2005

(1) SCE comments that on October 25, 2004, FERC issued an order approving a settlement agreement between California parties and Dynegy. SCE calculates that DWR should receive nearly $120 million in November 2004, and should include this in its 2005 Determination.

Response: The Department has reviewed the Dynegy settlement and FERC Order and has included expected settlement-related receipts in its projection of beginning account balances for the 2005 Revenue Requirement Period.

(2) SCE states that it is SCE's understanding that prior receipts associated with the El Paso Energy Settlement Agreement and the Williams Energy Marketing & Trading Settlement Agreements are reflected in over collections in DWR's reserve accounts at the end of 2004 and in the Extraordinary Receipts portion of the Proposed Determination.

Response: All 2004 receipts related to the El Paso Energy Settlement Agreement and the Williams Energy Marketing & Trading Settlement Agreements are reflected in the projected Operating Account balance on December 31, 2004. The projected 2005 receipts are shown in the Extraordinary Receipts portion of the Determination.

On October 29, 2004, Mr. Paul Clanon, Director of the CPUC Energy Division sent a letter to Mr. Peter Garris, Deputy Director of the DWR, providing comments in response to the "Notice of Additional Material to be Relied Upon in Determination of a Revenue Requirement".

In Summary, the Energy Division's analysis indicates that DWR's proposed revenue requirements includes $340 million more than is necessary to meet the Department's likely 2005 expenses and required reserves.

Response: The Energy Division's comments on the September 9, 2004 proposed determination were submitted on October 29, 2004 after many changes had already been made to the Proposed Determination. It is important to note that the Department's power charge revenue requirement process returns to ratepayers any funds not required to pay for power costs or maintain reserves. For instance, in its 2003 Supplemental Revenue Requirement, the Department returned over $1 billion; in its 2004 Supplemental Revenue Requirement, the Department identified an additional $245 million reduction in its revenue requirement.

The anticipated 2005 Power Charge Revenue Requirement reflects amounts received and projected to be received from settlements with El Paso Energy, Williams Energy Marketing and Trading and Dynegy Power Marketing, allowing the Department to maintain its necessary reserves, pay for energy purchases and collect from ratepayers $3.9 billion dollars, an amount that is $372 million lower than the amount determined in DWR's 2004 Supplemental Revenue Requirement.

The table below compares the operating account balances projected in the 2004 Supplemental Determination with the amounts reflected in this 2005 Determination, which uses preliminary actual operating results through September 2004 and projected operating results for October through December 2004. The $1.724 balance noted below is reflected as the starting balance for the 2005 Revenue Requirement Period, providing ratepayers with a $385 million reduction in the amounts that otherwise would need to be collected in 2005.

Ending 2004 Operating Balance Comparison

2004 Supplemental Revenue Requirement	Current Projection	Difference
($millions)	($millions)	($millions)
1,340	1,724	385

(1) The Energy Division estimates a potential savings of $118 million, resulting from the use of additional actual data in its modeling updates for 2004.

Response: The Department relied on the power charges from Appendix A of Commission Decision 04-08-050 in the projection of its cash flows for 2004 included in the Proposed Determination. The IOUs have not remitted at the Commission approved rates; rather, they have remitted to the Department at higher rates resulting from Commission Decision 04-01-028, which implemented the original 2004 Revenue Requirement. The result from remittances being based on higher rates is an over-collection from the IOUs by the Department in 2004. This over-remittance is reflected in the projected ending operating account balance noted in the table above and is thereby used to lower the amount that must be collected in 2005. Any over-remittances based on allocation decisions specific to previous annual DWR revenue requirements should be used to provide ratepayer relief. Following the quantification of such over-remittances, these amounts can be utilized to provide rate relief during the CPUC's implementation of the Department's 2005 Revenue Requirement. In addition, the Department has updated its modeling efforts to reflect preliminary actual operating results through September 2004.

A portion of the $118 million referenced in Table 1 results from the revenues received from direct access customers. The CPUC's comments regarding CRS revenue forecasts relate to the allocation of DWR's Retail Revenue Requirements. DWR believes that any revenues that result from a Direct Access CRS and offset bundled ratepayer remittances are more appropriately forecast when the CPUC allocates and reconciles DWR's Revenue Requirements based on the best available information to the IOUs, the CPUC and DWR regarding Direct Access volumes and likely CRS collections. In any event, this offset is an allocation exercise and does not change the Department's Determination. DWR intends to work cooperatively with the CPUC to ensure that any forecast of CRS revenues is accurate and allows for an appropriate reduction for any power charge rate established for bundled customers.

(2) The Energy Division estimates a potential savings of $180 million from meeting the Minimum Operating Expense Available Balance within calendar year 2005.

Response: The Department has covenanted in the Bond Indenture to include in its revenue requirements amounts estimated to be sufficient to cause the amount on deposit in the Operating Account at all times during any calendar month to, at a minimum, equal the Minimum Operating Expense Available Balance ("MOEAB"). The Bond Indenture leaves to the Department the determination as to how far into the future this minimum test of sufficiency should be met. Moreover, the covenant addresses the minimum requisite projected amount to be on deposit in the Operating Account, and leaves to the Department the determination as to what total reserves are appropriate or required in the fulfillment of its duties under Section 80134 of the Act. The Department also notes that the Summary of Material Terms and the Restated Addendum do not define "excess amounts" with respect to the Operating Account and do not provide a covenant that the Operating Account will be reduced to any particular level.

The MOEAB is to be determined by the Department at the time of each revenue requirement determination and, when the Department is not procuring the residual net short, is to be an amount equal to the largest projected difference between the Department's projected operating expenses and the Department's projected Power Charge revenues during any one month period during the revenue requirement period, taking into account a range of possible future outcomes (i.e., "stress cases").

For the purposes of this 2005 Determination, the MOEAB is determined to be $282 million. The Department projects to exceed the MOEAB at all times during 2005 and to reach the minimum balance in the later half of 2006. The Department has determined that the amount projected to be on deposit in the Operating Account, including the amount therein that acts as a reserve for Operating Expenses, is just and reasonable, based in part on the following: (1) potential gas price volatility, (2) potential gas price escalation, (3) year-over-year revenue requirement volatility, and (4) credit rating agency and credit and liquidity facility considerations, as well as the factors discussed below under "Sensitivity Analysis" and in Section E—"Key Uncertainties in the Revenue Requirement Determination". As the Energy Division notes in its letter, the Department adopted a similar modeling approach in connection with its 2004 Supplemental Determination of Revenue Requirements, which was allocated by CPUC Decision 04-08-050.

Revenue requirement volatility is illustrated by the following. If 2005 revenue requirements were set so that the Operating Account balance were to actually reach the MOEAB during calendar year 2005, the Department projects that it could not avoid falling below the MOEAB in February, 2006, because charges implemented as of January 1, 2006 would not be reflected in cash flows until the second half of February. Also, even if the February failure to meet the MOEAB were ignored (which, of course, the Department cannot do), in order to meet the MOAEB during the balance of 2006, the 2006 revenue requirement would need to be at least 7% higher than projected under this 2005 Determination.

(3) The Staff estimates a potential savings amount of $27 million by revising the cost estimates of the CPA contract.

Response: The Department has revised its cost estimate for the CPA contract to $16.9 million for 2005.

A summary comparing the 2005 Power Charge Revenue Requirement Proposed Determination, which initiated the APA process, with this Determination is presented in Section B, Table B-1.

I. COMMENTS RECEIVED ON PROPOSED REVISIONS TO THE NOVEMBER 4, 2004 DETERMINATION AND THE DEPARTMENT'S RESPONSE

On March 7, 2005, PG&E and SCE submitted comments to the Department in response to DWR's Proposed Revised 2005 Determination of Revenue Requirements. In its comments, PG&E states that (1) DWR has not provided relief to ratepayers or responded to PG&E's assertions that components of DWR's 2005 Revenue Requirements contain "above-market" costs as a result of the long-term power purchase contracts entered into by DWR; (2) it is unclear if DWR has reduced its 2005 Revenue Requirements to reflect all possible reductions in the Department's reserve accounts; and (3) in connection with the CPUC's revenue requirement allocation proceeding, DWR should provide further information concerning the allocation alternatives of fuel cost savings resulting from the Natural Gas Purchase Contract between DWR and Williams Energy Marketing and Trading ("Williams"). In its comments, SCE recommends that in connection with the CPUC's revenue requirement allocation proceeding, DWR should provide additional information concerning the allocation alternatives of fuel cost savings resulting from the Natural Gas Purchase Contract between DWR and Williams as well as additional information to assess the allocation of proposed reductions in DWR's gas collateral costs.

I. DWR's has determined that costs in this Revised Determination associated with long-term power purchase contracts are just and reasonable under AB 1X and the Regulations.

PG&E argues that DWR has not granted relief to ratepayers or specifically responded to PG&E's assertion that the 2005 Determination contains "above-market" costs associated with long-term power purchase contracts. With respect to costs associated with DWR's long-term contracts that are included in this Revised 2005 Determination, the Department has assessed whether those costs are just and reasonable in light of the circumstances faced by the Department at the time the various decisions implementing DWR's power purchase program were made.[14] As explained in DWR's August 16, 2002 Determination of Revenue Requirements, and in the Department's Reconsideration of the August 16, 2002 Determination, issued on August 19, 2004, DWR does not believe that the Legislature intended that the Department conduct an after-the-fact reasonableness review.[15] By law, the Department is not permitted to realize a profit from its activities, nor does it have any shareholder capital from which to pay for costs that cannot be included in rates or charges. Any just and reasonable review and determination undertaken by the Department, must be consistent with the mandate of Section 80134 of the Water Code that the Department establish and revise revenue requirements sufficient, together with other moneys, to provide for all of the Department's costs.

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[14] 23 California Code of Regulations Section 517.

[15] Both DWR's August 16, 2002 Determination of Revenue Requirements and the Department's Reconsideration of the August 16, 2002 Determination are included in the administrative record supporting this Revised 2005 Determination.

The Department's Regulations require the application of the following standards in determining whether its revenue requirements are just and reasonable:

> To protect ratepayer interests, the record of the determination must demonstrate by substantial evidence that the revenue requirement is just and reasonable, considering the circumstances existing or projected to exist at the respective times of the department's decisions concerning whether to incur the costs comprising such revenue requirement, and the factors which under the Act [AB 1X] are relevant to such determination and such decisions, including but not limited to the following:
>
> (1) The development and operation of the program as provided in the Act is in all respects for the welfare and the benefit of the people of the state, to protect the public peace, health, and safety, and constitutes an essential governmental purpose;
>
> (2) The department must do those things necessary and authorized under chapter 2 of the Act to make power available directly or indirectly to electric consumers in California; provided that except as otherwise stated, nothing in the Act authorizes the department to take ownership of the transmission, generation, or distribution assets of any electrical corporation in the State of California;
>
> (3) Upon those terms, limitations, and conditions as it prescribes, the department may contract with any person, local publicly owned electric utility, or other entity for the purchase of power on such terms and for such periods as the department determines and at such prices the department deems appropriate taking into account all of the factors listed in section 80100 of the Water Code;
>
> (4) The department may sell any power acquired by the department pursuant to the Act to retail end use customers, and to local publicly owned electric utilities, at not more than the department's acquisition costs, including transmission, scheduling, and other related costs, plus other costs as provided in section 80200 of the Water Code;
>
> (5) The department must, at least annually, and more frequently as required, establish and revise revenue requirements sufficient, together with any moneys on deposit in the Electric Power Fund, to provide for all of the amounts listed in section 80134(a) of the Water Code, including but not limited to the repayment to the General Fund of appropriations made to the Electric Power Fund for purposes of the Act; and

(6) Obligations of the department authorized by the Act shall be payable solely from the Electric Power Fund.[16]

Pursuant to the Regulations, the Department must rely on the standards set forth above to determine whether the Revised 2005 Determination is just and reasonable. The various factors set forth in the above standards in large part mirror the statutory directives of AB 1X. These directives were part of the circumstances facing the Department at the time it made various procurement decisions underlying this Revised Determination.

Importantly, a comparison to market price is not the sole consideration with respect to whether DWR's energy costs are just and reasonable under AB 1X. The Legislature intended that the Department's power supply program achieve an overall portfolio of contracts for energy resulting in *reliable service at the lowest possible price*.[17] The Department's objectives were to meet this two-part directive: reliability and cost-effectiveness. Accordingly, the Department's core strategy was to emphasize longer-term contracts as a means to secure new generation capacity for greater reliability and long-term price stability. This strategy underwent periodic review and modification as the power supply program progressed and market conditions changed.[18] DWR's long-term power purchase contracts must be assessed in part based on whether they contributed to the achievement of the goal of increased reliability at lower prices, by shifting supply from the spot market to a long-term supply.

There is substantial evidence in the administrative record, which explains the condition of California's energy market, DWR's procurement objectives and its portfolio planning efforts.[19] This evidence supports a just and reasonableness determination of long-term contract costs included within the Revised 2005 Determination.

When compared to the alternative of continuing to purchase large volumes of energy at excessive prices in the spot market during 2001, the long-term contract costs included within the Revised 2005 Determination are just and reasonable. The following facts provide substantial evidence to support a determination that the Department's costs were just and reasonable pursuant to Section 80110 of the Water Code and the Regulations: the dramatic reduction in spot market prices during 2001 following DWR's contracting efforts,[20] the reduction in total costs as compared to prices that were experienced prior to contracting efforts undertaken by the Department,[21] and projected prices and energy

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16 23 California Code of Regulations § 517.

17 Water Code Section 80100 (a).

18 See, Declaration of Ronald O. Nichols dated August 8, 2002 at paragraphs 38 through 88. *See also*, Declaration of Peter S. Garris dated August 9, 2002.

19 *See e.g.*, Declaration of Ronald O. Nichols dated August 8, 2002 at paragraphs 4 through 43 and exhibits thereto — *History of DWR's Net Short Energy Procurement Process Under Long-Term Contract*.

20 *See e.g.*, Declaration of Ronald O. Nichols dated August 8, 2002 at paragraphs 71 through 72. *See also e.g.*, California Department of Water Resources Activities and Expenditures Report Quarter Ended June 30, 2001.

21 Memorandum dated December 10, 2001 from the Department of Water Resources to Mary D. Nichols regarding Department of Water Resources' Response to the State Auditor's Draft Report. Declaration of Ronald O. Nichols dated

shortages absent actions taken by the Department.[22] To maintain a reliable power supply, achieve lower prices in the market and halt the unsupportable continued drain on the State General Fund, the Department reasonably determined to move expeditiously to convert spot market purchases in an explosive market into longer-term bilateral contracts.[23] Based on the information provided above, the Department has demonstrated that the long-term power contract costs contained in its Revised 2005 Determination meet the criteria established to determine that those costs are just and reasonable.[24]

The Department has also demonstrated that contract related savings are utilized to reduce the Department's revenue requirement thereby providing the Commission with the opportunity to pass these savings on to ratepayers. The Department has explained its efforts to incorporate amounts received and amounts projected to be received as a result of contract renegotiations and settlements of disputes involving DWR's long-term power contracts.[25] This Revised 2005 Determination reflects amounts received and projected to be received from settlements with El Paso Energy, Williams Energy Marketing and Trading and Dynegy Power Marketing. These receipts in part account for a Revised 2005 Determination that is less than DWR's 2004 Supplemental Revenue Requirement.

While DWR intends to continue to look for opportunities to renegotiate its long-term power purchase contracts to obtain benefits for California ratepayers consistent with the statutory directives set forth in AB 1X, the Department has determined that the costs associated with the long-term contract for 2005 are just and reasonable, consistent with AB 1X and the Regulations, and are appropriately included in the Revised 2005 Determination.

II. The Department's determination to maintain reserves is just and reasonable.

In its comments, PG&E states that it is not clear if DWR has reduced its 2005 Revenue Requirements to reflect all possible reductions in the Department's reserve accounts. PG&E's argument echoes comments DWR received by the Energy Division of the CPUC during DWR's administrative process leading to the November 4, 2004 Determination. DWR responded to the comments of the CPUC's Energy Division as part of its November 4, 2004 Determination.[26]

August 8, 2002 at paragraph 39 and Exhibit 12 thereto—*History of DWR's Net Short Energy Procurement Process Under Long-Term Contract.*

22 *See e.g.,* Declaration of Ronald O. Nichols dated August 8, 2002 at paragraph 7.

23 Memorandum dated December 10, 2001 from the Department of Water Resources to Mary D. Nichols regarding Department of Water Resources' Response to the State Auditor's Draft Report.

24 In its Comments, PG&E specifically references the contract between DWR and Sempra Energy Resources ("Sempra"). PG&E argues that DWR has asserted that it entered into this contract based on fraudulent misrepresentations. DWR notes that the DWR-Sempra contract is currently subject to an arbitration proceeding before the American Arbitration Association.

25 2005 Determination at pp. 33-34.

26 2005 Determination at pp. 59-61.

As explained in the November 4, 2004 Determination, the Department has covenanted in the Bond Indenture to include in its revenue requirements amounts estimated to be sufficient to cause the amount on deposit in the Operating Account at all times during any calendar month to, at a minimum, equal the MOEAB.[27] The Bond Indenture addresses the minimum requisite projected amount to be on deposit in the Operating Account and leaves to the Department the determination as to what total reserves are appropriate or required to fulfill its duties under AB 1X. The MOEAB is to be determined by the Department at the time of each revenue requirement determination and, when the Department is not procuring the residual net short, is to be an amount equal to the largest projected difference between the Department's projected operating expenses and the Department's projected Power Charge revenues during any one month period during the revenue requirement period, taking into account a range of possible future outcomes (i.e. stress cases).

For purposes of the Revised 2005 Determination, DWR determined the MOEAB to be $275 million. The Department projects to exceed the MOEAB at all times during 2005. The Department determined that the amount projected to be on deposit in the Operating Account, including the amount therein that serves as a reserve for Operating Expenses, is just and reasonable, based in part on the following factors: (1) potential gas price volatility, (2) potential gas price escalation, (3) credit rating agency and credit and liquidity facility considerations, as well as other factors discussed in the November 4, 2004 Determination.[28]

III. The Department intends to assist the CPUC and interested parties in connection with the allocation of DWR's Revised Determination

In their comments, PG&E and SCE both request that DWR consider providing additional analysis in connection with the CPUC's proceeding addressing the allocation of DWR's 2005 revenue requirements. Specifically, PG&E and SCE request that DWR consider providing additional information concerning the allocation alternatives of fuel cost savings resulting from the Natural Gas Purchase Contract between DWR and Williams as well as proposed reductions in DWR's gas collateral costs. Consistent with Section 7.2 of the Rate Agreement between DWR and the CPUC, the Department intends to continue to provide any necessary information to the CPUC in order for the Commission to complete its proceeding involving the implementation of DWR's Revised 2005 Determination of Revenue Requirements.

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[27] Under the Trust Indenture, the MOEAB is defined as "at the time Revenue Requirements are submitted to the Commission . . . (i) for so long as the Department is procuring all or a portion of the Residual Net Short, $1 billion, and, (ii) thereafter, the maximum amount projected by the Department by which Operating Expenses exceed Power Charge revenues during any one calendar month during that Revenue Requirement Period. Such projections shall be based on such assumptions the Department deems to be appropriate after consultation with the Commission and may take into account a range of possible future outcomes." (Trust Indenture at p. 11)

[28] November 4, 2004 Determination at pp. 38-39 "Sensitivity Analysis" and pp.40-41 "Key Uncertainties in the Revenue Requirement Determination". If the Revised 2005 Determination were calculated so that the Operating Account balance were to actually reach the MOEAB during calendar year 2005, the Department projects that it could not avoid falling below the MOEAB in February 2006, because charges implemented as of January 1, 2006 would not be reflected in cash flows until the second half of February.

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

Volume	Record Number	Date	Record Title
DWR05pRR	01	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	02	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	03	11/19/2003	Record of Coordination – Conference Call to discuss the 2005 revenue requirement process, between Frank 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	04	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	05	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	06	1/22/2004	CPUC Decision 04-01-049 - Opinion Regarding Western Area Power Administration Interest, dated January 22, 2004
DWR05pRR	07	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:

Volume	Record Number	Date	Record Title
			"Response to California Department of Water Resources First Data Request"), dated January 30, 2004
DWR05pRR	08	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	09	3/10/2004	Record of Coordination – Ron Oechsler (NCI) with Ted Mureau (SCE) regarding SCE 2004 sales forecast, dated March 10, 2004
DWR05pRR	10	3/18/2004	Record of Coordination – DWR Data Request to Pacific Gas and Electric Company Pertaining to Generation Availability, dated March 18, 2004
DWR05pRR	11	3/18/2004	Record of Coordination – DWR Data Request to Southern California Edison Company Pertaining to Generation Availability, dated March 18, 2004
DWR05pRR	12	3/18/2004	Record of Coordination – DWR Data Request to San Diego Gas & Electric Company Pertaining to Generation Availability, dated March 18, 2004
DWR05pRR	13	3/19/2004	California Energy Commission Energy Facility Status, dated March 19, 2004
DWR05pRR	14	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	15	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	16	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	17	3/26/2004	Western Area Power Administration's forecast of capacity and energy for load and resources for the 12-month period beginning

Volume	Record Number	Date	Record Title
			March 1, 2004, dated March 26, 2004
DWR05pRR	18	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
DWR05pRR	19	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	20	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	21	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	22	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	23	4/9/2004	California Energy Resources Scheduling Division Long-Term Contracts Overview - March 2004, dated April 9, 2004
DWR05pRR	24	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	25	4/12/2004	Record of Coordination – Email from Ron Oechsler relating to WAPA Forecast, dated April 12, 2004
DWR05pRR	26	4/13/2004	Record of Coordination – Email from Ron Oechsler relating to SDG&E economic assumptions, dated April 13, 2004

Volume	Record Number	Date	Record Title
DWR05pRR	27	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
DWR05pRR	28	4/22/2004	Motion of Joint Settling Parties for Waiver of Rule 51.2 and Adoption of Settlement Agreement, dated April 22, 2004
DWR05pRR	29	4/23/2004	Southern California Edison Data Request No. 5 to the California Department of Water Resources, dated April 23, 2004
DWR05pRR	30	4/26/2004	Press Release – "Governor Schwarzenegger Announces $280 Million Refund from Dynegy," dated April 26, 2004
DWR05pRR	31	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 direct access availability for large customers to negotiate their own energy supply contracts.
DWR05pRR	32	4/28/2004	CPUC President Michael Peevey's letter responding to Governor Schwarzenegger and CPUC press release, dated April 28, 2004
DWR05pRR	33	4/28/2004	Pacific Gas and Electric Company Data Request No. 5 to California Department of Water Resources, dated April 28, 2004
DWR05pRR	34	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	35	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

Volume	Record Number	Date	Record Title
			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
DWR05pRR	36	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	37	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	38	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	39	5/7/2004	Pacific Gas and Electric Company Data Request No. 6 to California Department of Water Resources, dated May 7, 2004
DWR05pRR	40	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

Volume	Record Number	Date	Record Title
DWR05pRR	41	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
DWR05pRR	42	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	43	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	44	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	45	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	46	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	47	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	48	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

Volume	Record Number	Date	Record Title
			May 17, 2004
DWR05pRR	49	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	50	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
DWR05pRR	51	5/19/2004	Department of Water Resources Electric Power Fund Financial Statements as of March 31, 2004, prepared May 19, 2004
DWR05pRR	52	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	53	5/20/2004	California Hydroelectric Energy Outlook, California Energy Commission Staff Paper, dated May 20, 2004
DWR05pRR	54	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	55	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	56	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	57	5/27/2004	CPUC Decision 04-05-054: "Opinion Denying Petition To Modify Decision 04-01-

Volume	Record Number	Date	Record Title
			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	58	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
DWR05pRR	59	6/4/2004	CPUC Assigned Commissioner's Ruling and Scoping Memo, R.04-04-003, dated June 4, 2004
DWR05pRR	60	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	61	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	62	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	63	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	64	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	65	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	66	6/9/2004	CPUC Decision 04-06-014, Opinion Adopting Standard Contract Terms and

Volume	Record Number	Date	Record Title
			Conditions, R.04-04-026, dated June 9, 2004
DWR05pRR	67	6/9/2004	CPUC Decision 04-06-015, Opinion Adopting Market Price Referent Methodology, R.04-04-026, dated June 9, 2004
DWR05pRR	68	6/10/2004	CPUC Assigned Commissioner's Ruling Regarding Reliability Issues, R.04-04-003, dated June 10, 2004
DWR05pRR	69	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	70	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	71	6/11/2004	Record of Coordination – Jim McMahon with Matt Masters, PG&E, regarding sales forecast updates, dated June 11, 2004
DWR05pRR	72	6/11/2004	Record of Coordination – Jim McMahon with Greg Katsapsis, SCE regarding sales forecast updates, dated June 11, 2004
DWR05pRR	73	6/11/2004	Record of Coordination – Jim McMahon with Colin Cushnie, SCE regarding sales forecast updates, dated June 11, 2004
DWR05pRR	74	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	75	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	76	6/16/2004	CPUC ALJ Ruling Clarifying Instructions on Long-Term Plan Filings, R.04-04-003, dated June 16, 2004
DWR05pRR	77	6/17/2004	Record of Coordination – Paul Luther

Volume	Record Number	Date	Record Title
			Correspondence and Meeting Summary: ProSym Run 47 Preparation; PG&E Generation Resources, dated June 17, 2004
DWR05pRR	78	6/17/2004	Record of Coordination – Paul Luther Correspondence and Meeting Summary: ProSym Run 47 Preparation; SCE Generation Resources, dated June 17, 2004
DWR05pRR	79	6/18/2004	Pacific Gas and Electric Company's response to DWR's June 16, 2004 Data Request, dated June 18, 2004
DWR05pRR	80	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	81	6/20/2004	CONFIDENTIAL - NOT FOR PUBLIC RELEASE: DWR Permanent Cost Allocation Comparison Exhibit, dated June 20, 2004
DWR05pRR	82	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	83	6/24/2004	Record of Coordination – Email Gordon Pickering with NCI staff regarding PacifiCorp Fuel Charges Forecast 2005-2025, dated June 24, 2004
DWR05pRR	84	6/24/2004	Record of Coordination – Conference call with NCI and SCE regarding SCE Transition Contracts, dated June 24, 2004
DWR05pRR	85	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	86	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	87	7/1/2004	PG&E's Energy Resource Recovery Account, A.03-08-004, Compliance Review Testimony for the June 1-December 31, 2003

Volume	Record Number	Date	Record Title
			Record Period (redacted), dated July 1, 2004
DWR05pRR	88	7/7/2004	Record of Coordination – Email string-NCI and Sempra Utilities regarding Gas price model input, dated July 7, 2004
DWR05pRR	89	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	90	7/8/2004	CPUC Decision 04-07-025 (relating to Direct Access load growth principles), dated July 8, 2004
DWR05pRR	91	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	92	7/8/2004	CPUC Resolution E-3831 (CRS for customer generation departing load), dated July 8, 2004
DWR05pRR	93	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	94	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	95	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	96	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	97	8/2/2004	Record of Coordination – CERS, PG&E, and NCI meeting regarding true-up allocation of 2003 long-term contract costs, dated August

Volume	Record Number	Date	Record Title
			2, 2004
DWR05pRR	98	8/6/2004	Record of Coordination – Voicemail from PG&E to Brian Grubbs regarding Breakout of 2003 Costs, dated August 6, 2004
DWR05pRR	99	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	100	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	101	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	102	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
DWR05RRd	103	9/09/04	California Department of Water Resources Notice of and Proposed Determination of a Revenue Requirement for the Period January 1, 2005 Through December 31, 2005, including by reference materials contained within Section H – Annotated Reference Index of Materials Upon Which the Department Relied to Make Determinations, dated September 9, 2004
DWR05RRd	104	9/09/2004	Memoranda to: Mark Huffman-Pacific Gas and Electric Company; James P. Scott Shotwell, Southern California Edison; Meredith Allen, San Diego Gas & Electric; Andrew Ulmer, Simpson Partners, and Jeannie Lee, California Department of Water

Volume	Record Number	Date	Record Title
			Resources from Brian Grubbs, Navigant Consulting, Inc. transmitting the " CDWR Release of Financial Model and ProSym Files in Support of the Proposed 2005 Revenue Requirement," dated September 9, 2004 CONFIDENTIAL - NOT FOR PUBLIC RELEASE: Consultant's ProSym 49 Output Files and Financial Model - Proprietary Model and Confidential Data contained are not for public release - Protected under relevant Non Disclosure Agreements, dated September 9, 2004
DWR05RRd	105	9/13/2004	Record of Coordination – Email Andrew Ulmer to Distribution regarding formatting errors in the California Department of Water Resources' September 9, 2004 Proposed Determination, dated September 13, 2004
DWR05RRd	106	9/17/2004	Record of Coordination – Email correspondence between J.P. Shotwell, SCE and Frank Perdue, NCI: questions and responses regarding the 2005 Proposed Revenue Requirement Determination, dated September 17, 2004
DWR05RRd	107	9/20/2004	Pacific Gas and Electric Company's first data request to the California Department of Water Resources, dated September 20, 2004
DWR05RRd	108	9/20/2004	Pacific Gas and Electric Company's second data request to the California Department of Water Resources, dated September 20, 2004
DWR05RRd	109	9/21/2004	Letter from Andrew Ulmer to Craig Buchsbaum responding to Pacific Gas and Electric Company's September 20, 2004 data requests to the California Department of Water Resources, dated September 21, 2004
DWR05RRd	110	9/30/2004	Pacific Gas and Electric Company's Comments on the California Department of Water Resources' Proposed Determination of Revenue Requirements for the Period January 1, 2005, Through December 31, 2005, dated September 30, 2004
DWR05RRd	111	9/30/2004	Southern California Edison's Comments on the California Department of Water Resources' Proposed Determination of

Volume	Record Number	Date	Record Title
			Revenue Requirements for the Period January 1, 2005, Through December 31, 2005, dated September 30, 2004
DWR05RRd	112	9/30/2004	Record of Coordination – Email from Michael Strong, San Diego Gas and Electric Company with Comments on the Proposed Determination of the Revenue Requirement for 2005, dated September 30, 2004
DWR05RRd	113	10/20/2004	Notice of Additional Material to be Relied Upon in Determination of a Revenue Requirement, dated October 20, 2004 (1) Amended and Restated Power Purchase Agreement between DWR and Clearwood Electric Company, LLC, dated July 2, 2004 (2) Amended and Restated Power Purchase Agreement Between DWR and Kings River Conservation District, dated August 18, 2004 (3) Letter Agreement Between DWR and Kings River Conservation District, dated September 21, 2004 (4) Management Briefing on KRCD Project Cost Discussions, dated June 24, 2004 (5) Estimated Annual Capacity Costs for Kings River Conservation District Peaker PPA (6) 2005 Kings River Conservation District Fact Sheet – Background on Kings River Conservation District Peaker PPA (7) Official Statement of Kings River Conservation District in connection with bond sale (8) October 1, 2004 Kings River Conservation District proforma (9) CONFIDENTIAL - SCE Prepared Testimony – 2005 Forecast of Operations – supporting SCE 2005 Energy Resources Recovery Account Application before the California Public Utilities Commission (Application 04-04-008)

Volume	Record Number	Date	Record Title
			(10) CONFIDENTIAL - SCE Option Contract Summary (11) CONFIDENTIAL - SCE Option Contracts
DWR05RRd	114	10/21/2004	Southern California Edison's Response to The Alliance for Retail Energy Markets' Protest of Advice 1827-E, dated October 21, 2004
DWR05RRd	115	10/27/2004	Pacific Gas and Electric Company's Comments on the Determination of Revenue Requirements of the California Department of Water Resources for the Period January 1, 2005, Through December 31, 2005 Based on Additional Material Provided by DWR, dated October 27, 2004
DWR05RRd	116	10/27/2004	Southern California Edison's Supplemental Comments on the California Department of Water Resources' Proposed Determination of Revenue Requirements for the Period January 1, 2005 through December 31, 2005, dated October 27, 2004
DWR05RRd	117	10/29/2004	California Public Utilities Commission's Comments on the California Department of Water Resources' Proposed Determination of Revenue Requirements for the Period January 1, 2005 through December 31, 2005, dated October 29, 2004
DWR05RRd	118	11/02/2004	Record of Coordination – Jim Olson to Frank Perdue with work paper supporting Dynegy settlement amounts, dated November 2, 2004
DWR05RRd	119	4/26/2004	Press Release from Standard & Poor's: California Department of Water Resources' 'BBB+' Rating Removed from CreditWatch, dated April 26, 2004
DWR05Revised	120	2/18/2005	Gas Price Update: Pacificorp Contract – Variable Gas Transportation Charges Data only 2005-2025, DWR Base Case Forecast, DWR Stress Case Forecast.
DWR05Revised	121	2/18/2005	Gas Price Update: DWR Base Case Gas Forecast
DWR05Revised	122	2/18/2005	DWR Stress Case Gas Forecast
DWR05Revised	123	2/23/2005	Gas Collateral calculation: 2005 Revenue

Volume	Record Number	Date	Record Title
			Requirements Hedging Costs Calculations – PS 54 Fuel Volumes
DWR05Revised	124	1/3/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: PG&E Gas Supply Plan 5
DWR05Revised	125	2/1/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: SDG&E Advice Letter 1661-E, Submittal of SDG&E Gas Supply Plan for DWR Tolling Agreements Pursuant to Decision 03-04-029 and Resolution E-3854
DWR05Revised	126	11/29/2004	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: PG&E Gas Supply Plan - Appendix Draft
DWR05Revised	127	1/11/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: SCE Gas Supply Plan Presentation to PRG
DWR05Revised	128	2/1/2005	CONFDENTIAL – NOT FOR PUBLIC RELEASE: SCE Gas Supply Plan
DWR05Revised	129	2/7/2005	SCE Letter to CPUC Transmitting Response to Data Request of 12/28/2004
DWR05Revised	130	1/12/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: Data responses From IOUs regarding gas collateral costs: SCE
DWR05Revised	131	1/12/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: SCE Contract Gas Costs Response
DWR05Revised	132	1/11/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: Data responses From IOUs regarding gas collateral costs: PG&E
DWR05Revised	133	1/12/2005	CONFIDENTIAL – NOT FOR PUBLIC RELEASE: Data responses From IOUs regarding gas collateral costs: SDG&E
DWR05Revised	134	12/2/2004	Decision 04-12-014: "Opinion Implementing A Permanent Allocation Of The Annual Revenue Requirement Determination Of The California Department Of Water Resources".
DWR05Revised	135	12/16/04	Letter from Peter Garris to the CPUC regarding the 2005 Revenue Requirements. At the prehearing conference on December 15, 2004, the Department was requested to extend the date for implementation of the 2005 Revenue Requirements to March 17, 2005. This memo agrees to the extension of

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			the deadline and confirms this extension will not have a material adverse affect on the Department.
DWR05Revised	136	12/16/04	Decision 04-12-048: "Opinion Adopting PG&E, SCE, and SDG&E Long-Term Procurement Plans".
DWR05Revised	137	1/13/05	Decision 05-01-036: "Order Granting Limited Rehearing of Decision 04-12-014"(Perm allocation). Considered the allegations raised in SDG&E application for rehearing and are of the opinion that limited rehearing should be granted to permit parties to propose how above-market costs should be determined. Denied all other issues raised by SDG&E.
DWR05Revised-Final	138	3/7/05	PG&E Comments on the Proposed Revised 2005 Determination.
DWR05Revised-Fina;	139	3/7/05	SCE Comments on the Proposed Revised 2005 Determination.
DWR05Revised-Fina;	140	3/7/05	DWR Letter to the CPUC on the DRAFT Decision to Implement the 2005 Rev. Req.