State of California

Department of Water Resources

Summary of 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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REVISIONS TO THE DEPARTMENT'S NOVEMBER 4, 2004 DETERMINATION

On November 4, 2004, the State of California Department of Water Resources (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. Unless otherwise defined herein, capitalized terms have the meanings given to them in the November 4, 2004 Determination.

The Department has reviewed certain matters relating to its 2005 revenue requirement, 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 the Department's 2005 Revenue Requirement (the "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.

The $33 million offset to power costs results from updated projected savings related to the Williams Natural Gas Purchase Contract based on the Department's revised natural gas price forecast. The resultant savings amount 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). 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.

These revisions address only those changes under the aforementioned subjects. All other previous assumptions underlying the November 4, 2004 Determination remain unchanged. Based on the timing of these revisions, some dates and quantitative references have also been updated throughout the Revised 2005 Determination to reflect actual operating results through December 31, 2004 (the November 4, 2004 Determination reflected actual operating results through September 30, 2004). These changes, while important to consider, have not significantly affected the Department's Revised 2005 Revenue Requirements.

The Department's Revised 2005 Determination reflects all changes (including relevant updates to Section J – Annotated Reference Index of Materials Upon which the Department Relied to Make Determinations) not included herein, and is part of the administrative record supporting this Revised 2005 Determination. Appropriate section headings, similar to those included in the November 4, 2004 Determination, are also included herein to facilitate document comparison and review.

A. THE REVISED DETERMINATION

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.

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.

B. BACKGROUND

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

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

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**

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

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.

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.

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 lessexpensive 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.

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.[1] 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.[2] 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.

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

[1] 23 California Code of Regulations Section 517.

[2] 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.

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.[3]

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*.[4] 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

[3] 23 California Code of Regulations § 517.

[4] Water Code Section 80100 (a).

the power supply program progressed and market conditions changed.[5] 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.[6] 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,[7] the reduction in total costs as compared to prices that were experienced prior to contracting efforts undertaken by the Department,[8] and projected prices and energy shortages absent actions taken by the Department.[9] 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.[10] 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.[11]

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5 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.

6 *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*.

7 *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.

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

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

10 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.

11 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.

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.[12] 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.[13]

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, <u>at a minimum</u>, equal the MOEAB.[14] 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

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[12] 2005 Determination at pp. 33-34.

[13] 2005 Determination at pp. 59-61.

[14] 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)

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 under "Sensitivity Analysis" and in Section E—"Key Uncertainties in the Revenue Requirement Determination" of the Revised 2005 Determination.[15]

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.

[15] 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.