STATE OF CALIFORNIA GRAY DAVIS, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

January 8, 2002

Item 1
2/7/2002

TO: PARTIES OF RECORD IN APPLICATION 00-11-038 ET AL.

This is the proposed decision of Administrative Law Judge (ALJ) Pulsifer, previously designated as the principal hearing officer in this proceeding. It will be on the Commission's agenda at the next regular meeting, which is scheduled for February 7, 2002. This matter was categorized as ratesetting and is subject to Pub. Util. Code § 1701.3(c). Pursuant to Resolution ALJ-180 a Ratesetting Deliberative Meeting to consider this matter may be held upon the request of any Commissioner. If that occurs, the Commission will prepare and mail an agenda for the Ratesetting Deliberative Meeting 10 days before hand, and will advise the parties of this fact, and of the related ex parte communications prohibition period.

The Commission may act at the regular meeting on February 7, 2002, or it may postpone action until later. If action is postponed, the Commission will announce whether and when there will be a further prohibition on communications.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision as provided in Article 19 of the Commission's "Rules of Practice and Procedure." These rules are accessible on the Commission's website at http://www.cpuc.ca.gov. Pursuant to Rule 77.3 opening comments shall not exceed 15 pages. Consistent with Rule 77.2, comments are due on the proposed decision within 20 days of its date of mailing. No extensions of this comment period will be granted, nor will any late-filed comments be accepted. Pursuant to Rule 87, we will reduce the reply comment period provided for in rule 77.5 to four days. Because the fifth day following opening comments falls on a weekend, good cause exists for shortening the reply period to four days to provide sufficient time for review of reply comments. Therefore, comments must be filed and served by January 28 and reply comments must be filed and served by February 1. Finally, comments must be served separately on the ALJ and the assigned Commissioner, and for that purpose I suggest hand delivery, overnight mail, or other expeditious method of service. Comments and reply comments should be served on the ALJ electronically at trp@cpuc.ca.gov.

/s/ LYNN T. CAREW
Lynn T. Carew, Chief
Administrative Law Judge

LTC: hkr

Decision **PROPOSED DECISION OF ALJ PULSIFER (Mailed 1/8/2002)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (E 3338-E) for Authority to Institute a Rate Stabilization Plan with a Rate Increase and End of Rate Freeze Tariffs.	Application 00-11-038 (Filed November 16, 2000)
Emergency Application of Pacific Gas and Electric Company to Adopt a Rate Stabilization Plan. (U 39 E)	Application 00-11-056 (Filed November 22, 2000)
Petition of THE UTILITY REFORM NETWORK for Modification of Resolution E-3527.	Application 00-10-028 (Filed October 17, 2000)

(See Appendix D for List of Appearances.)

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O P I N I O N

I. Overview

This decision implements cost recovery of the revenue requirements of the California Department of Water Resources' (DWR) relating to its power purchase program pursuant to Assembly Bill 1 of the First Extraordinary Session (Stats. 2001, Ch. 4), hereafter referred to as AB1X. On November 5, 2001 DWR submitted to the Commission its most recent revenue requirement of $10,003,461,000, representing the total to be collected from utility customers of the three major California utilities covering the period from January 17, 2001 through December 31, 2002.

In this decision, we determine how DWR revenue collections are to be allocated among the customers of the three major California electric utilities: Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E), and we establish procedures to implement the collection process. DWR will collect its revenue requirements through charges remitted from billings to retail customers of the three major electric utilities based on designated per-kWh charges as set forth in this decision. We allocate the total DWR revenue requirement among each of the three major utilities' service territories as follows:

Utility	($000's) Revenue Allocation	% Allocation
PG&E	$ 4,765,407	47.6%
SCE	$ 3,674,066	37.7%
SDG&E	$ 1,563,989	15.6%
Total	$ 10,003,461	100%

As described below, we agree with the goal of allocating DWR costs in relation to the costs of providing service. We do not believe, however, that attempts to segregate disproportionately higher priced DWR power for allocation exclusively to northern California consumers is a proper or fair application of traditional cost-based ratemaking policies. The primary purpose of the Public Utilities Act is to insure the public adequate service at just and reasonable rates without discrimination. (Pub. Util. Code § 451 et seq., 761; see also United States Steel Corp. v. Public Utilities Com., 29 Cal. 3d 603, 610 (1981), quoting Pacific. Tel. & Tel. v. Public Utilities Com. 34 Cal.2d 822, 826 (1950).) The allocation proposed by SCE and SDG&E would unreasonably discriminate against customers served by PG&E by charging the latter a disproportionately high cost per kWh.

The allocation issue here, involving costs incurred by single entity (i.e., DWR) purchasing power on behalf of customers in three separate utility service territories is novel, and is not addressed by traditional cost-based ratemaking procedures as typically applied. Nonetheless, the allocation approach we adopt is consistent with the philosophy underlying traditional cost-based ratemaking. Our adopted approach allocates DWR costs in relation to the relevant cost driver, namely the net short position by utility.

Our statewide pro rata allocation recognizes the integrated nature of power procurement undertaken by DWR for California utility customers, but also adjusts for utility-specific differences, where applicable, as proposed by TURN. As a basis for the utilities to remit revenues to DWR in accordance with these allocations, we adopt a per-kWh charge for customers in the service territory of each utility of 10.047 cents/kWh for PG&E, 10.309 cents/kWh for SCE and 9.947 cents/kWh for SDG&E. These adopted DWR charges form the basis for the utilities to remit funds to DWR that they are currently collecting. We do not, however, change the overall level of retail rates for PG&E, SCE, or SDG&E in today's order. We will address the need for any change in rates for SDG&E customers in order to meet DWR's costs of serving SDG&E customers in a separate docket (Application (A.) 00-10-045 et al). [1] For SCE and PG&E customers, any need for a change in overall rates charged to customers as a result of this decision cannot be addressed until we after we issue our decision on utility retained generation (URG) issues.

We note that the high DWR contract prices now in effect in California reflect the exorbitant wholesale electricity costs caused by the crisis manufactured by wholesale electricity sellers and traders over the past year. These rates measure, in part, the terrible price California has had to pay to restore stability. Individual Commissioners and Governor Gray Davis have previously endorsed contract renegotiations to reduce prices that were set when market prices were at or near their peak. (Exhibit 160, Weil, p. 4.) DWR now forecasts that from October 1, 2001 through the end of 2002, average DWR contract prices will be 3.3 times average residual net short prices. (Reference Item C, DWR, November 5 revenue requirement document, p. 16, Table 6; compare DWR contract costs to residual net short costs for Q4 2001 and all of 2002.) DWR assumes that residual net short energy will be purchased in spot markets.

It is our hope that the actions of DWR and the utilities, as well as the efforts of public and private parties involved in cases at the Federal Energy

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[1] SDG&E has already been granted an interim rate increase in D. 01-09-059 to enable it to remit payments to DWR under AB 1X based on a DWR charge of 9.02 cents per kWh. The interim increase became effective on September 30, 2001.

Regulatory Commission (FERC) and in the courts to reduce costs will be successful, and that we will be able to revisit the DWR's revenue requirement to lower these charges in the future.

II. Regulatory and Statutory Mandates Relating to DWR Power Procurement

The actions we take in today's order follow the statutory scheme that was enacted in response to emergency conditions confronting California's major electric utilities and their customers. On January 17, 2001, Governor Davis issued a Proclamation that a "state of emergency" existed within California resulting from unanticipated and dramatic increases in the wholesale price of electricity.[2] The Governor's Proclamation stated that "unanticipated and dramatic increases in the price of electricity have threatened the solvency of California's major public utilities, preventing them from continuing to acquire and provide electricity sufficient to meet California's energy needs." Governor Davis therefore ordered DWR to assume responsibility for procurement of a major portion of electric power resources for customers of California's three major electric utilities in order help stabilize market conditions. On January 19, 2001 Governor Davis signed Senate Bill 7 from the First Extraordinary Session of 2001-2002 (SB7X). This bill directed DWR to procure electricity on an interim basis and appropriated $400 million for this purpose.[3]

DWR formally began procuring electric power on behalf of customers of the three major electric utilities on January 17, 2001.[4] DWR undertook to meet

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[2] The Governor's Proclamation was attached as Appendix A to Decision (D.) 01-01-061.

[3] SB 7X authorized DWR activities only for a period of twelve days in January.

[4] DWR had regularly engaged in electric purchase and sale activities in connection with the State Water Project for a number of years. In December 2000 it also apparently

Footnote continued on next page

the utilities' net short requirements[5] through a combination of contractual power purchases and spot market purchases, including purchases of ancillary services. DWR has also, from time to time, assumed responsibility for imbalance energy and Independent System Operator (ISO) charges. The utilities continue to have the obligation to serve pursuant to Public Utilities Code Section 451 and Water Code Section 80002.

On February 1, 2001, the California Legislature enacted AB1X, which added Division 27 to the California Water Code, Sections 80000 et seq. AB1X authorized DWR to continue its power purchasing activity through December 31, 2002. Among other things, that statutory enactment provides the following measures relating to DWR's procurement of power for California consumers:

- Authorizes DWR to purchase power and sell it to retail customers of PG&E, SCE, and SDG&E, as well as to customers of municipal utilities. (Water Code Sections 80100 and 801160.)
- Establishes the DWR Electric Power Fund in the State Treasury, into which are deposited all revenues payable to DWR relating to power procurement, including proceeds from power sales, bond sales, appropriations and other sources. (Water Code Section 80200(b).)
- Authorizes DWR to sell bonds. (Water Code Section 80130.)
- Requires DWR to establish a revenue requirement to defray the costs of its activities and to communicate that revenue

worked with the ISO to fund ISO electricity procurement activities on an informal basis, using State Water Project moneys.

[5] The term "net short" came to be used to describe the difference between utility retail demand and the supply resources provided by the utility's own generation and committed power purchase contracts with qualifying facilities (QFs) and other suppliers.

requirement to the Commission for recovery in retail electric rates. (Water Code Section 80134.)

- Allows DWR to recover charges for power established by the Commission after providing its revenue requirement to the Commission. (Water Code Section 80110.)

Thus, AB1X contains provisions to provide funds to DWR from revenues generated by applying charges to the electricity that it sells to the customers of the investor-owned utilities. AB1X requires that DWR include in its revenue requirement "…amounts necessary to pay for power purchased by it…" (Water Code Section 80134(a)(2).) Amounts in the Electric Power Fund are to be spent on the "…cost of electric power…." (Water Code Section 80200(b)(2).) The term "power" is specifically defined as "electric power and energy, including but not limited to, capacity and output or any of them." (Water Code Section 80010(f).)

Water Code Section 80002.5 states that "[i]t is the intent of the Legislature that power acquired under this division shall be sold to all retail end use customers served by electrical corporations, …." Water Code Section 80104 explains that "[u]pon the delivery of power to them, the retail end use customers shall be deemed to have purchased that power from the department. Payment for any sale shall be a direct obligation of the retail end use customer to the department."

AB1X assigns roles to the Commission and DWR respectively in establishing the terms of the relationship between DWR as interim power seller and the customers of the investor-owned utilities. The key provision of the statute is Water Code Section 80110, which provides in relevant part:

> The department shall retain title to all power sold by it to the retail end use customers. 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.

> Such revenue requirements may also include any advances made to the department hereunder or hereafter for purposes of this division, or from 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.

Water Code Section 80110 provides that DWR is entitled to recover in rates amounts sufficient to enable it to comply with Section 80134, which are, under the bond structure currently being undertaken by the Administration and the State Treasurer, the revenues that may be pledged for support of bonds that DWR is authorized to issue pursuant to Section 80130. Section 80134(a) provides:

> 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[6] 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 obligations entered into by it pursuant hereto, in the amounts and at the times the same shall become due.

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[6] Prior to commencing any program of power purchases DWR is required to "… assess the need for power in the state in consultation with the Public Utilities Commission and local publicly owned electric utilities and electrical corporations in the state and such other entities in the state as the department determines are appropriate." (Water Code Section 80100(f).)

(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.[7]

(b) The department shall notify the commission of its revenue requirement pursuant to Section 80110.

III. Joint Roles of CPUC and DWR in Implementation of DWR Requirements

The process for the compilation, review, and implementation of the DWR revenue requirement must conform to the governing requirements of the California Water Code pursuant to AB1X. The process involves joint roles for both DWR and the Commission. Water Code Section 80110 provides that DWR "shall be entitled to recover, as a revenue requirement, amounts and at the times necessary to enable it comply with Section 80134, and shall advise the commission as the [DWR] determines to be appropriate."

As provided for under Public Utilities Code Section 451, however, charges for DWR's revenue requirements that are passed through to utility customers

[7] Administrative costs are to be approved in the annual Budget Act. (Water Code Section 80200(c).)

must be "just and reasonable". Public Utilities Code Section 451 states in relevant part:

> "All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful."

In this regard, Water Code Section 80110 states:

> For purposes of this division and except as otherwise provided in this section, the Public Utility [sic] Commission's authority as set forth in Section 451 of the Public Utilities Code shall apply, except any just and reasonable review under Section 451 shall be conducted and determined by [DWR].

Consistent with Water Code Section 80110, this Commission continues to have authority under Public Utilities Code Section 451 for determining the allocation of DWR's revenue requirement among California utility customers. Nonetheless, "any just and reasonable review [of the aggregate DWR revenue requirement]…shall be conducted and determined by " DWR.

The California Constitution provides that the Legislature may confer additional authority on the Commission "unlimited by the other provisions of this constitution but consistent with this Article [XII]." (California Constitution, Article XII, Section 5.) In confirming the authority of the Commission to set charges and terms for DWR power sales pursuant to Public Utilities Code Section 451 "for purposes of this division," the Legislature is acting within its powers, notwithstanding DWR's status as a state agency.

In this decision, we therefore establish charges to recover the revenue requirement for DWR as presented to us pursuant to Section 80110. The revenue requirement includes forecasts and representations about future events, including issuance of bond with estimates of reserve requirements and interest rates that may or may not reflect actual conditions at the time the bonds are sold. We accept these forecasts and representations, as well as DWR's estimate of when the bonds will be issued. As appears more fully below, we intend to establish a mechanism for reconciling forecasted revenue requirements with actual costs, for rate setting purposes.

On an interim basis, the Commission has issued several orders during 2001 to permit DWR to collect revenues for its power purchases. We made those decisions with limited information because of the urgent need to provide immediate revenue to DWR. Today's decision establishes charges based on a final DWR revenue requirement for the 2001-2002 timeframe, based on the modeling information provided by DWR. As the agency responsible for implementing utility charges to collect the DWR revenue requirement, the Commission has worked cooperatively with DWR to facilitate DWR's determination of its revenue requirement, and to provide the opportunity for parties in this proceeding to participate in that process, including through workshops, written comments, and data requests, as described below.

IV. Procedural Summary of DWR Revenue Requirement Implementation

DWR communicated its initial estimate of its revenue requirements by letter to the Commission dated May 2, 2001.[8] In that letter, DWR requested that the Commission "establish specific rates payable to the Department for power sold by the Department to retail end use customers within the State."

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[8] A copy of DWR's May 2, 2001 letter was appended to D.01-05-064 as Attachment B.

On June 18, 2001, PG&E filed a motion for evidentiary hearings on the calculation, allocation, rate design and implementation of DWR's revenue requirement under AB1X. PG&E sought to consolidate DWR revenue requirement issues with the scheduled hearings to establish the URG revenue requirement in this docket. A companion motion was filed by SCE on June 19, 2001, supporting PG&E's proposal.

The assigned Administrative Law Judge (ALJ) issued a ruling dated July 12, 2001, that denied these motions, but provided an opportunity for parties to file comments on DWR revenue requirement and allocation issues. The ruling also provided an opportunity for parties to review and comment on the DWR response to data requests sent by Commissioner Geoffrey F. Brown.[9] The ruling stated that a separate Commission decision would be prepared to address the DWR revenue requirement and allocation issues. These actions were prompted by the evident sense of urgency in moving forward with the Commission decisions that were predicates for the issuance of the bonds developed and structured by DWR and the Treasurer's Office.

A. July 23, 2001 Update

DWR responded to Commissioner Brown's data request on July 23, 2001, concurrently revising its revenue requirement. The DWR July 23 submittal was served on the parties as an attachment to a Joint Assigned Commissioners' Ruling (ACR) on July 24, 2001, and also on parties in the SDG&E dockets. The ACR sought further information from DWR, allowed parties to comment on

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[9] Commissioner Brown sent letters dated June 18, 2001, and June 26, 2001, to the Director of DWR, Thomas M. Hannigan, seeking additional information to supplement the data provided in the May 2, 2001 revenue requirement letter referenced above.

DWR's submission, and convened a technical workshop on July 27. Parties filed written comments on August 3 on DWR's revenue requirement submittal.

B. August 7, 2001 Update

DWR submitted another update on August 7, incorporating revised calculations relating to its forecasts. DWR's update revised the quantities of bilateral contracts held by PG&E and SDG&E, the level of Qualifying Facility (QF) contract output for SDG&E, and the quantity and associated costs of QF output for Edison, which in turn affected ancillary service costs. The cumulative result lowered the share of the net short energy requirements for SDG&E and, to an extent, for SCE customers. It increased the net short energy requirements for PG&E customers. An August 9, ALJ ruling allowed parties to comment on DWR's updated revenue requirement.

PG&E, SCE, SDG&E, The Utility Reform Network (TURN), the Office of Ratepayer Advocates (ORA), Aglet Consumer Alliance (Aglet), the Federal Executive Agencies (FEA), and (jointly) the California Large Energy Consumers Association (CLECA) and the California Manufacturers and Technology Association (CMTA) filed comments on August 3, 2001 in response to the July 23 DWR revenue requirement submittal. Various parties also filed supplemental comments to the August 7 DWR update, and to the questions raised in the August 9 ruling.

An ALJ Draft Decision to implement cost recovery of the DWR revenue requirement was mailed on September 6, 2001. Comments on the Draft Decision were filed on September 12, 2001. The Draft Decision was subsequently withdrawn from Commission consideration following the issuance of a ruling setting hearings on revenue allocation issues as explained further in Section IX below.

C. October 19, 2001 Preliminary Update

On October 19, DWR submitted a preliminary draft of another DWR revenue requirement update, and ultimately answered the previously submitted data requests in the context of the revised revenue requirement. DWR's revisions from its August 7th submittal included changes to reflect the following:

1. Increased direct access loads resulting from the Commission's September 20, 2001 cutoff date for retail end-users to enter into contracts with alternative electric service providers;
2. Increased financing costs principally resulting from delay in the issuance of long-term bonds to refinance the Department's interim loan;
3. Reductions in natural gas prices;
4. Load forecast changes to reflect the effects of only the 20/20 Program for the year 2001 and those demand-side management ("DSM") and conservation-related activities that were authorized by legislation;
5. Revised power volumes under long-term contracts;
6. Revised methodology for calculating ancillary service costs;
7. Revised prices estimates for sales of contracted power to wholesale power purchasers; and
8. Revised timing of the receipt of revenues by DWR.

DWR held its own informational workshop on the preliminary update in Sacramento on October 22, and received informal comments on October 26, 2001. Those comments focused on the financing, power contracts, past costs and the models supporting the filing. On November 1, 2001, DWR provided responses to parties' data requests. In consideration of those comments, DWR finalized its draft, and made a formal revised submittal to the Commission on November 5, 2001.

D. November 5, 2001 Final Update[10]

In its November 5, 2001, revised submittal, DWR included changes from its October 19 draft relating to: the interim financing rolling coverage requirements; accounting of cash flows due to cash reporting of the Power Fund received from the Department of Finance; and updated volumes and costs of the net short, ancillary services and associated ISO charges through October 2001. DWR is also acquiring, through the ISO's ancillary services market, the electric energy and capacity required for grid reliability in the IOUs' service areas, to the extent these services are not otherwise provided by the IOUs through their retained generation, as described more fully later in this order.

V. DWR's Representations Concerning the Reasonableness of Its Revenue Requirement

DWR asserts that it is not obligated by law to provide information regarding its revenue requirement in public workshops before the staff of the Commission, but has done so on a voluntary basis. DWR believes that there is no basis under law for the Commission to disallow any costs it has incurred to meet its emergency procurement obligations, and no basis for parties other than

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[10] DWR sent a letter to Commissioner Brown on December 6, 2001, submitting additional updated information relating to its revenue requirement determination. The additional information resulted in an approximate 1% net reduction in total expenditures. DWR believes that its November 5th revenue requirement continues to be appropriate as a basis for establishing charges in this order, and that the impacts of any subsequent developments can be taken into account in a subsequent true up proceeding.

DWR to undertake the "just and reasonable" determination of its revenue requirement. [11]

In its transmittal letter to Commissioner Brown dated November 5, 2001, DWR stated that it has determined that the revenue requirement contained in its latest submittal is "just and reasonable." DWR states that its revenue requirement is based on reasonable forecasts and proposes to work with PG&E and Edison to seek a balance between self-provisioning of ancillary services and their respective net short energy and ancillary service costs. DWR agrees that such cost tradeoffs would be reflected in future adjustments of its revenue requirement. Similarly, DWR agrees that any necessary revisions to its natural gas price forecasts that result in a lower revenue requirement will be incorporated prospectively.

DWR prepared its revenue requirement in cooperation with its consultant, Navigant Consulting (Navigant), which prepared the forecasts of net short energy requirements that support the revenue requirements. The financial model used by Navigant has been reviewed by Montague DeRose & Associates (financial advisor to DWR), Public Resources-Advisory Group (financial advisor to the State Treasurer's Office), and analysts of JPMorgan. PriceWaterhouseCoopers has completed an independent audit of the mathematical accuracy of the financial model. These reviews pertain principally to the financial results of the models.

DWR provides the following information relevant to its determination that its revenue requirements are just and reasonable:

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[11] See Letter Dated August 1, 2001 from Director of DWR to Energy Division Chief of the Commission, providing DWR Responses to Data Requests, page 28, response to Aglet Question 3.

- DWR used a competitive solicitation method for obtaining power supply bids.
- Power purchases by DWR are at cost and DWR is a governmental agency that receives neither equity return nor any form of economic return for its energy purchases.
- Projected spot market purchases not obtained via contract are estimated based upon a competitive, marginal cost, market clearing price projection.
- DWR's revenue requirement will be adjusted or trued-up over time to reflect only those costs which are actually incurred by DWR for power supply acquisition and administration.
- Actual and projected costs are below prior cost estimates submitted to the Commission in May 2001 and earlier market projections.

Water Code Section 80100 sets forth the relevant considerations for DWR when it undertakes to purchase power, following its consultation with the Commission, utilities and public agency utilities:[12]

(a) The intent of the program is to achieve an overall portfolio of contracts for energy resulting in reliable service at the lowest possible price per kilowatt hour.

(b) Contract supplies should fit each aspect of the overall energy load profile.

(c) As much low-cost power should be secured as possible under contract.

(d) The duration and timing of contracts made available from sellers must be considered.

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[12] An issue has been raised as to whether DWR carried out the requirement under AB1X that it consult with the Commission, the utilities, and public agency utilities concerning the need for power before it began to implement its power procurement program. It is not necessary to resolve this issue in making the determinations set forth in the instant order.

(e) The length of time sellers of electricity offer to sell such electricity must be considered.

(f) As much firm and nonfirm renewable energy as possible should be secured.

Parties filed comments regarding DWR's latest update on November 13, 2001. The November 5, 2001 revenue requirement forms the basis for the revenue allocation evidentiary hearings that were conducted, and also are the basis for the implementation of charges to be remitted by the three utilities as authorized in this order.

The parties take issue with DWR's representation that its revenue requirement is "just and reasonable." Parties generally claim that DWR still has not provided adequate documentation to explain and support its revenue requirement. Parties assert that they have not been permitted a thorough review and analysis of the methodology and assumptions underlying the DWR revenue requirement.

Various parties protest DWR's continued failure to provide detailed workpapers to its revenue requirement determination, or to provide complete responses to data requests. The October 26, 2001, Assigned Commissioner's Ruling directed DWR to provide supporting workpapers with its November 5 Revenue Requirement. Although DWR provided an updated CD-ROM disk containing the results of its computer modeling, it failed to provide detailed workpapers as to key assumptions, factors and calculations forming the basis of its revenue requirement. Appendix B of this decision sets forth comments of the parties on specific elements of DWR's revenue requirement forecast with which they take exception.

We acknowledge parties' disagreements regarding the manner in which DWR has sought to fulfill its procedural and substantive obligation to "conduct" any reasonableness review under Section 451, and to make a determination that its revenue requirement is reasonable. In our role as the agency responsible for allocating utility revenues to recover DWR's revenue requirement, we have worked cooperatively to facilitate the development of DWR's revenue requirement. We have provided for multiple opportunities through workshops and written comments for DWR and parties to this proceeding to interface and exchange information relevant to the determination of the DWR revenue requirement. We believe that this process has been productive in improving the quality of information underlying the DWR revenue requirement. The Commission is very appreciative of the prompt and diligent response by parties to the DWR submissions and offerings.

We note that forecasts of costs included in DWR's revenue requirement submission are projections that may or may materialize. However, as provision is made for subsequent adjustments of the DWR revenue requirements in periodic updates, variances between forecast and actual results can be taken into account in revising DWR charges prospectively. An overcollection in one year, for example, would reduce the next year's revenue requirement and the charges needed to recover it. We intend to continue to cooperate with DWR to facilitate the process of accurately identifying relevant costs and implementing necessary recovery measures as mandated by statute.

In any event, the Legislature has expressly committed the determination of whether DWR's power procurement costs are just and reasonable to DWR, and not to the Commission. Accordingly, determination of the justness and reasonableness of DWR's total costs under Section 451 is beyond the scope of this order. We make no independent verification as to whether each cost element of Water Code Section 80100 has been appropriately considered by DWR.

The role of the Commission under the AB1X, however, is to establish utility charges to recover the costs of authorized DWR activities once the revenue requirement has been determined by DWR. As a result, it is proper for us to implement utility charges, as adopted in this order, to enable DWR to recover its revenue requirement as authorized under AB1X.

We summarize below the principal elements comprising the DWR revenue requirement, and then take up the process of converting the power purchase program into a set of charges that, when applied to sales volumes, will produce revenues to pay for DWR AB1X-authorized costs. As determined in Section VIII below, we establish the percentage allocation of the DWR revenue requirement to be assigned to each utility service territory. We then translate the percentage allocation into a cents-per-kWh charge that will form the basis for remittance of funds to DWR by each utility that covers the period from January 17, 2001 through December 31, 2002.

VI. Elements Comprising the DWR Revenue Requirement

DWR computes its revenue requirement in a two-step process. Step 1 involves the aggregate determination of DWR's gross expenditures. In Step 2, DWR applies proceeds from its forecast external interim financing to determine the net remaining amount that it needs to collect from utility customers over the two year period and submits that amount to the Commission as its AB1X-authorized revenue requirement. The revenue requirement includes recorded amounts for prior months dating back to January 17, 2001, and includes forecast amounts for future months through December 31, 2002.

DWR's updated revenue requirement for all three utilities totals $10.003 billion, as summarized in Appendix A of this decision. The revenue requirement represents total expenditures of $18.014 billion, less the proceeds from external financings. The remaining balance of $10.003 billion is the DWR revenue requirement to be recovered from utility customers covering the period from January 17, 2001 through December 31, 2002, and reflects an aggregate amount for customers of all three electric utilities' service territories. The $10.003 billion revenue requirement is the amount before deducting interim proceeds that have already been remitted to DWR by the utilities' customers on an interim basis.

DWR reports its revenue requirement in accordance with the categories specified in Water Code Section 80134, together with certain additional detail: [13]

- Operating expenses, including purchased power under fixed price and short term contracts, as well as ancillary services.
- Administrative and Overhead
- Demand Side Management
- Allowance for Uncollectibles
- Lead (Lag) Accrual to Cash
- Interim Loan Costs

A summary of DWR's revenue requirement is set forth in the Appendix A of this order. These elements are summarized below.

A. Long Term and Short Term Power Purchases

DWR's forecast of total operating expenses from January 17, 2001 through December 31, 2002 for the three utilities includes $5.284 billion for long-term contract power, and $9.534 billion for residual net short-term purchases.[14] .

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[13] DWR explained in Exhibit C of its August 7 update how its forecasted cost categories are consistent with Water Code Section 80134.

[14] "Residual net short purchases" include all net short purchases other than ancillary services, in addition to DWR power purchases under bilateral contracts.

"Long-term" contracts are those that are more than 90 days in duration. The costs associated with purchases under long term contracts in existence as of November, 2001 are shown in the column labeled "Contract Power" in Table 1 below. An estimate of the energy associated with long-term purchases is shown in the column labeled "Contracts" in Table 2 below.

"Short-term" contracts generally consist of bilateral contracts longer than day-ahead purchases with a duration of 90 days or less. For contracts in place as of October 1, 2001, these are a component of the column labeled "Residual Net Short" in Table 1. An estimate of the energy associated with short-term purchases is a component of the column in Table 2 labeled "Residual Net Short Purchases."

Table 1 below summarizes on quarterly basis the average cost per mWh of power acquired by DWR over the 24-month period. Table 2 summarizes the total DWR purchases, by long-term and short-term amounts.

TABLE 1
AVERAGE NET SHORT ENERGY COSTS
($/MWH)

	DWR Contracts	Residual Net Short	Weighted Average Power Cost
Q12001	-	269	269
Q2 2001	132	249	222
Q3 2001	128	117	121
Q4 2001	121	42	79
Q12002	115	36	78
Q2 2002	143	30	87
Q3 2002	118	38	84
Q4 2002	111	36	82

TABLE 2 ESTIMATED DWR ENERGY PURCHASES (GWH)			
	Total Net Short Purchases	Contracts	Residual Net Short Purchases
Q3 2001	16,054	6,929	9,125
Q4 2001	11,312	5,361	5,951
Q12002	10,153	5,466	4,687
Q2 2002	8,648	4,391	4,257
Q3 2002	13,399	7,660	5,739
Q4 2002	11,788	7,239	4,549

The DWR cost per mWh shown in Table 1 and energy purchases shown in Table 2 exclude any sales to Direct Access customers. Transmission- and distribution-related costs have not been included in DWR's revenue requirement and are presumed to be covered by the utilities 's own rates. Fuel costs are included in the total energy costs through the use of a generation dispatch model based on quantity and price of energy. The natural gas price assumptions used in DWR's analysis are described in Appendix C.

B. Ancillary Service Costs

DWR estimates ancillary service cost responsibility of $1.102 billion using a proxy for procured capacity and composite ancillary service market prices, adjusted for other ancillary services charge responsibilities not incorporated therein. DWR used data collected from June 1999 through November 2000 to compare (1) monthly historical ancillary services capacity procured on the market (including self provision) to the monthly system load, and (2) the monthly composite ancillary services price to the spot market price. Historical ancillary services market capacity was calculated as 13 percent of load for the period. Historical ancillary services composite price (weighted average of spin, non-spin, regulation up, regulation down, and replacement reserves) was calculated as 31 percent of spot market prices.

DWR made an adjustment to account for expected self-provided ancillary services costs for which DWR would not bear cost responsibility. In addition, ancillary service costs based on IOU data received November 1, 2001 reflecting the period from January 17 through October 2001 have been included in the revenue requirement net of self-provision by the utilities.

C. Administrative, General, and Overhead

DWR's estimated administrative and general expenses of $99 million are summarized by quarter in Appendix A in the column labeled "A&G." Table 3 below provides more detail on the administrative and general expenses of DWR.

TABLE 3
ADMINISTRATIVE, GENERAL, AND OVERHEAD EXPENSES
(MILLIONS OF DOLLARS)

	Labor (Including Benefits)	Capital Expenditures	Professional Service Fees	Other Administrative and General
Q12001	$ 2	$1	$5	$2
Q2 2001	2	1	5	2
Q3 2001	2	1	5	2
Q4 2001	2	1	5	2
Q12002	2	5	6	1
Q2 2002	2	5	6	1
Q3 2002	2	5	6	1
Q4 2002	2	5	6	1
Total	$16	$24	$44	$13

'Other Expenses include costs of administration and billing related to the 20/20 Program in 2001.

D. Conservation/Load Management Costs

Table 4 below presents actual and expected conservation and load management costs by quarter included in the revenue requirement. DWR has included costs and associated energy savings for 2002 only for energy conservation and load management programs that have been authorized by either Executive Order of the Governor or by statute.[15] No such programs involving funding by the DWR as part of the net short energy procurement program have been authorized for 2002 and, therefore, no costs have been assumed. Any net short energy requirements (after the effects of conservation or DSM programs funded by the IOUs or others) are assumed to be met either by energy from DWR contract purchases or spot market purchases. Although the ISO may have incurred costs for voluntary load reduction programs for the summer of 2001, DWR has not considered those cost as part of its revenue requirement.

TABLE 4
COSTS TO AVOID OR MINIMIZE THE AMOUNT OF ACQUIRED POWER
(MILLIONS OF DOLLARS)

	Conservation Programs	Load Curtailment /	Conservation Rebates	Load Management Programs
Q12001	-	-	-	-
Q2 2001	3	-	1	-
Q3 2001	5	-	226	-
Q4 2001	-	-	62	-
Q12002	-	-	-	-

[15] Appendix II and Appendix VI of DWR's November 5 submittal provide further details on these programs in terms of the description of the programs, the amount of savings in MWh per month, and the associated costs for these programs and savings.

Q2 2002	-	-	-	-
Q3 2002	-	-	-	-
Q4 2002	-	-	-	-

E. Allowance for Uncollectibles

Included in DWR's revenue requirement is an allowance for uncollectible accounts. The allowance for uncollectible accounts was developed based on the DWR's assuming a pro rata share of recently observed utility uncollectible accounts. These amount to $7.7 million for calendar year 2001 and are expected to approximate $16 million during calendar year 2002.

F. Lead (Lag) Accrual to Cash

DWR adjusts its revenue requirement to account for the difference in time between the expenditure of cash to provide services to customers and the receipts of cash from them. Such amounts, totaling $401 million (lead), for the Revenue Requirement Period are included in Appendix A under the column labeled "Lead (Lag) Accrual to Cash." Leads (lags) are also used to adjust DWR's total operating costs to derive the its total operating expenditures.

These leads or lags can vary depending on the type of expense lead (i.e., payments by DWR for its contractual commitments versus payments for purchases of residual net short vs. payments by DWR to its other suppliers) and the revenue lag (i.e., the average amount of time it takes the DWR to receive payment for services provided). Some of the expense lags are defined within contracts or per the rules of the markets from which DWR arranges for purchases of residual net short. For the purpose of calculating the DWR revenue requirement, a revenue lag of 45 days was assumed for all prescheduled purchases by DWR. Revenue for all purchases by the ISO going forward are assumed to lag 90 days. Revenues attributed to ISO real-time and out-of-market purchases which have been procured for grid reliability have not been paid to date. They are assumed to be fully paid by February 2002. Expense lags are assumed to be as follows:

Contract expense: paid in 20 days;
Pre-scheduled residual net short energy: paid in 8 days; and
Other expenses: paid in 20 days.

G. Interim Loan Costs

Interim loan costs of $1.281 billion are included in the DWR's revenue requirement as displayed in the column labeled "Financing Cost" in Appendix A. These costs represent principal and interest payments on a $4.3 billion interim financing entered into by the DWR on June 26, 2001. The interim loan proceeds reduce the amount of revenues that would otherwise be required currently from customers. DWR plans to retire this interim financing from the proceeds of long-term bonds, expected to be issued during the second quarter of 2002. Nonetheless, DWR explains that the terms of the interim financing require that debt service costs of the interim financing be included for the entire period of the filing to protect DWR and lenders from exposure should bonds not be issued when expected.

In addition, DWR explains that ongoing debt service "coverage" tests must be met for the interim financing. If long-term bonds are not issued in the first half of 2002, DWR may need to reevaluate its revenue requirement for the balance of this revenue requirement filing period and for future periods. When the long-term bond financing is completed, DWR states that it will evaluate its revenue requirement and make any necessary adjustments.

AB1X authorizes DWR to issue up to approximately $13 billion in bonds to support its power purchase program. The bonds are projected to have a final maturity date of May 1, 2016. Until the bonds are sold, DWR is relying on the interim borrowing arrangements.

A relatively small portion of the proceeds from the bonds will be used to fund future power purchases, as a supplement the retail revenue requirement collected from customers in the utilities service territories. Future ratepayers will service the repayment of bond principal, together with accrued interest, in addition to paying for DWR power that they consume. Bond structure and size is an issue exclusively committed to the discretion of DWR. As developed more fully below, this decision applies the Commission's traditional ratemaking authority for DWR electricity sales, as shaped and directed by the Legislature in AB1X.

PG&E believes that DWR need not and should not increase revenue requirements to reflect interim financing costs which the projected surplus in the DWR Power Fund can cover prior to the expected issuance of DWR's power revenue bonds. Given this surplus, PG&E believes that DWR's power revenue bonds can and should be issued in time to avoid the need for any revenue requirement increase for the interim loan.

PG&E claims, however, that for DWR to increase its revenue requirement to cover interim loan costs while at the same time building up a surplus in the Power Fund which exceeds that amount constitutes a form of double-charging to PG&E's customers. Therefore, PG&E argues that DWR should reduce its revenue requirement to reflect payment of interim loan costs out of its Power Fund surplus, while at the same time reserving its rights to request a change in its revenue requirement during the next revenue requirement period, should its forecast power costs significantly change.

SCE similarly argues that DWR's revenue requirement should be approximately $940 million lower to reflect interim financing costs that will not be incurred, assuming that the bonds are issued as expected in the second quarter of 2002, with the bond proceeds paying off the interim loan.

Particularly in view of the significant level of costs projected for DWR's interim loan, we strongly recommend to DWR that it promptly remove the interim loan costs from its revenue requirement if it subsequently determines that it will not incur those costs. If, in fact, the long term bonds are issued at the end of June 2002, as now anticipated, DWR will not need to incur the interim loan costs that it has included in its revenue requirement for the latter quarters of 2002. We are scheduling the next updating of DWR's revenue requirement to begin June 1, 2002 (as discussed later in this order). We expect DWR to provide an adjustment to its revenue requirement at that time, reflecting the removal of the interim loan costs if, in fact, it still expects the long term bonds to be issued on schedule at the end of June 2002. Upon removal of those interim loan costs by DWR, if these sums are not needed to pay interest on the long term bonds or to reimburse the General Fund, we would expect to be able to implement a prompt adjustment to the DWR remittance charges payable by the utilities for the balance of 2002.

H. Deposits to Fund or Replenish Operating Reserves

The fund into which revenues collected from DWR's purchase program are deposited, from which DWR expenses are paid, and in which operating reserves are held, is defined as the "Power Fund." The Power Fund balance currently consists of the unexpended proceeds of the Department's interim financing and revenues from the sale of power to Customers and to off-system buyers. The fund balance of the Power Fund is projected to grow during the period of this filing due to the need to make interim financing principal and interest payments and provide debt service coverage for the interim financing.

DWR states that operating reserves will need to be replenished only if costs are significantly higher than the assumptions that underlie the Department's revenue requirement as presented in this filing.

VII. Miscellaneous Considerations Relating to DWR Revenue Requirement

A. Developments Subsequent to November 5 Submittal

By letter dated December 6, 2001, DWR advised Commissioner Brown regarding certain developments that transpired subsequent to November 5, 2001 that were relevant to the DWR revenue requirement. Most noteworthy among these developments was the issuance of a FERC order on November 7, 2001. On that date, FERC issued its Order Granting Motion Concerning Creditworthiness Requirement and Rejecting Amendment No. 40 (Order).[16] The Order confirms that DWR, as the creditworthy party, is responsible for purchases by the ISO for the net short positions of Edison and PG&E. Order, (mimeo) pp. 12-16. The FERC concluded that "[w]e have repeatedly directed the ISO to enforce its creditworthy standards under the Tariff." The Order further states:

> "The ISO is obligated under its Tariffs to invoice, collect payments from and distribute payments to DWR, as Scheduling Coordinator for all scheduled and unscheduled transactions made on behalf of DWR, including transactions where DWR serves as the creditworthy counterparty for the applicable portion of PG&E's and SoCal Edison's load."[17]

In its November 5 submittal, DWR qualified its ultimate responsibility for costs that require a creditworthy entity. In addition, DWR limited its

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[16] 97 FERC ¶61,151.

[17] *Id.*, (mimeo) p. 14.

responsibility to certain cost categories, and excluded many other ISO cost categories for which it should be responsible, at least in part, pursuant to the November 7 FERC Order. PG&E and SCE have argued that in compliance with the FERC Order, DWR's revenue requirement should be updated to include its full lawful obligations under the ISO's tariffs.

In its December 6 letter, DWR advised Commissioner Brown as to the effects of the FERC Order on its revenue requirements. DWR affirmed that the FERC ordered the ISO to bill DWR for ISO transactions with third party suppliers on behalf of the noncredit worthy entities PG&E and SCE. DWR indicated that the FERC Order caused the ISO to send it $956 million in invoices for the period January 17 through July 31, 2001.

DWR expects to make full payment of the ISO invoice for costs incurred in February 2001 under protest and expects to resolve disputed invoice charges for subsequent periods. As an attachment to its December 6 letter, DWR provided a summary of ISO invoices dated November 20, 2001 and the types and estimated amounts of additional costs being placed on DWR as a result of the FERC Order.

In its December 6 letter, DWR also provided miscellaneous updated calculations for other cost categories, including lead (lag) accruals to cash. DWR concluded, however, that the net effect of all the updated changes subsequent to November 5 were not significant enough to warrant a change in its previous $10.003 billion revenue requirement.

B. Responsibility for Payment of Franchise Fees

DWR's revenue requirement does not account for franchise fees associated with the power that it sells to utility customers. DWR believes that collection and payment of franchise fees are the responsibility of the utilities, and not DWR.

SCE takes exception to DWR's exclusion of franchise fees from its revenue requirement calculation. SCE currently pays franchise fees to cities based on the total amount of revenues billed to customers (total revenues includes both SCE and DWR revenues). SCE indicates that under its rate design, each unbundled rate component (e.g., distribution, transmission, public purpose programs) is design-based on a revenue requirement that includes franchise fee payments. That is, each estimated revenue requirement is grossed up by the most recent Commission-approved factor to determine the revenue requirement that is used to set rate levels. On a monthly basis, in the applicable ratemaking mechanism, the actual revenue that is generated from rate levels is reduced by a franchise fee amount calculated using the adopted factor. The revenues that remain after franchise fees are removed are then available to recover the costs associated with the applicable rate component.

SCE states that if this same methodology is not applied to the DWR revenue requirement, the franchise fees that SCE is obligated to remit to cities will have to be recovered through another utility rate component, such as distribution, transmission, or URG. SCE claims that such treatment would result in undercollection of its costs. It calculates that implementing the Commission-adopted franchise fees and uncollectible accounts would result in SCE's share of the DWR revenue requirement (based on July 23 data) being increased from $5.803 billion to $5.869 billion.

SCE argues that to appropriately establish the DWR revenue requirement and associated rate component, DWR's estimated revenue requirement should be grossed up by the currently effective franchise fee rate. SCE proposes that the revenues generated from the DWR rate component would first be reduced by the franchise fee factor and retained by SCE in order to recover franchise fee payments made by SCE to cities.

SCE believes that since the DWR rate component would be established based on the grossed up (including franchise fee payments) revenue requirement, reducing the amount of DWR revenue by this factor would still enable DWR to recover its revenue requirement. SCE maintains that the remaining revenue after accounting for franchise fees would be remitted to DWR for recovery of its incurred costs. SCE proposes to apply the same methodology to uncollectible accounts expense.

Comments on the issue of franchise fees were also filed by the City of San Diego and by the City and County of San Francisco, jointly with eight other municipalities (San Francisco et al.). San Francisco et al. state that franchise fees collected from electric service revenues are a vital source of funding for public services by local municipalities throughout the state. Moreover, under California law, municipalities are entitled to charge franchise fees as compensation for the use of public property to provide utility service. San Francisco et al. argue that the Commission should (1) clearly state that franchise fees must be paid on revenues associated with power purchased by DWR for utility customers, as well as on utility revenues; and (2) address how the collection and payment of such fees will occur. The City of San Diego goes farther, and argues that the Commission should require DWR to include a provision for franchise fees in its revenue requirement.

Although no party, nor DWR, has questioned the legal right of municipalities to franchise fees, the dispute over franchise fee remittances related to DWR power sales raises a number of legal and factual issues that have not been satisfactorily resolved by parties' comments. These questions include the legal right of municipalities to be paid franchise fees on DWR power sales, and the legal obligation of DWR to collect and remit franchise fees associated with its power sales. There are also unresolved questions over the utilities' obligations to remit franchise fees to municipalities on DWR power sales, and the extent to which current utility rates already include a provision for such franchise fees.

The proposal of the City of San Diego that we simply order DWR to collect franchise fees ignores the applicable legal statutes that assign responsibility to DWR—not the Commission—for determining the amount of its revenue requirement. Therefore, such a proposed order is not legally defensible or enforceable. Consequently, we shall adopt interim measures to enable the municipalities continue to receive franchise fees associated with DWR power sales pending further determinations of an appropriate course of action. In accordance with our continuing jurisdiction over the electric utilities, we direct the utilities to bear interim responsibility for remitting franchise fees to the municipalities for DWR power sales. Since we are not increasing the level of retail rates at this time, the utilities shall use funds generated from sales of power at existing rate levels in order to remit the franchise fees associated with DWR power sales.

We shall authorize each of the utilities to establish a memorandum account to track franchise fee payments that are made to the municipalities associated with DWR power sales. We shall expressly prohibit, however, any double recovery of franchise fees on DWR sales from utility customers. We shall determine a further disposition of the franchise fee issue following subsequent analysis of the legal and factual issues involved. We shall direct the ALJ to issue a procedural ruling calling for further comments to develop the record on the legal and factual issues pertinent to franchise fee remittances on DWR sales.

C. Treatment of Direct Access Customers in Allocating DWR Revenues

During the evidentiary hearings on revenue allocation, the ALJ ruled that issues relating to Direct Access customers' potential responsibility for a portion of the DWR revenue requirement were relevant in the determination of allocation issues. The ALJ also ruled, however, to defer consideration of Direct Access issues to a later phase of this proceeding. Accordingly, the allocations of revenue requirement adopted in this order do not take into account any potential impacts of Direct Access customer responsibilities for bearing a portion of DWR cost responsibility.

We believe that the potential impacts of Direct Access customers' responsibility for a share of the DWR revenue allocation should be addressed on a timely basis. The Commission is addressing the implementation of suspension of direct access in A.98-07-003. On December 24, 2001, a joint ruling was issued in this proceeding and in A.98-07-003, transferring that the issue of cost responsibility of direct access customers for the DWR revenue requirement into this proceeding. We direct the ALJ to issue a procedural ruling for addressing on a timely basis the issue of Direct Access customer responsibility for DWR charges in the determination of revenue allocation. Any true up of revenue allocations in a subsequent update proceeding will remain subject to the outcome of any subsequent order we may issue addressing Direct Access customer responsibility for DWR charges.

VIII. Allocation of Aggregate DWR Revenue Requirement Among the Utility Service Areas

A. Procedural Background

As noted previously, DWR computed a separate allocation of its revenue requirements to each of the three respective utility service territories in its initial submittal to the Commission. In its earlier submissions, DWR's suggested approach was to allocate its revenue requirement among customers on a uniform pro rata basis in relation to the net short position of each utility (i.e., the "postage stamp" approach).

In its most recent November 5, 2001 update, however, DWR refrained from computing any particular allocation of revenues. DWR acknowledges that the determination as to how the revenue requirement is to be allocated among utility customers is the responsibility of the Commission.

The assigned ALJ's Draft Decision to implement an allocation of DWR Revenue Requirements was mailed for comments on September 6, 2001. The Draft Decision proposed an allocation on the basis of where energy supplies were delivered into the power grid. Energy sources procured north of Path 15 were allocated to PG&E customers, while sources procured south of Path 15 were allocated to customers of SCE and SDG&E. This approach caused a disproportionately higher cost per kWh to be allocation to PG&E customers in comparison to southern California customers.

Parties filed comments on the Draft Decision on September 12, 2001. Upon review of the Draft Decision, PG&E filed a motion to compel production of computer models used to compute revenue allocations in the Draft Decision. In its motion, PG&E also requested evidentiary hearings on computer modeling and revenue allocation issues, arguing that the Draft Decision utilized computer modeling information that had not been made available for parties.

On September 19, 2001, Commissioners Lynch and Brown issued a Joint ACR, noting that DWR had agreed to provide confidential access to its computer models subject to a nondisclosure agreement. Parties executed a nondisclosure agreement with DWR for confidential access to DWR's computer models. On September 26, 2001, an ACR granted PG&E's motion for evidentiary hearings on the issue of DWR revenue allocation. The previously issued Draft Decision was withdrawn in anticipation of the evidentiary hearings, and a schedule was set for evidentiary hearings.

On October 5, 2001, a computer modeling workshop was held, to address questions regarding modeling assumptions underlying the DWR revenue allocation. Parties also submitted data requests to DWR relating to revenue requirements modeling. DWR agreed to provide responses on October 19, 2001.

Evidentiary hearings on DWR revenue allocation issues were conducted over five days from November 13 through 19, 2001. The parties sponsoring testimony were PG&E, SCE, SDG&E, ORA, TURN, AGLET, and CLECA. Opening briefs were filed on November 29, and reply briefs were filed on December 5, 2001. In addition to the parties noted above, briefs were filed by the Utility Consumer Action Network (UCAN), the County of Los Angeles and the City and County of San Francisco. Oral arguments were presented before the Commission on December 11, 2001.

DWR is not a party to the proceeding, and did not actively participate in the revenue allocation hearings. Nonetheless, the DWR November 5, 2001 revenue requirement submittal formed the basis for computing the allocations sponsored by parties. The DWR revenue requirement submittal was marked for identification as a reference item, and thus made a part of the record in this proceeding.

B. Parties' Positions

1. Overview

DWR revenue allocation proposals were made by PG&E, SCE, SDG&E, TURN, and ORA. DWR offered no allocation proposal in its most recent revenue requirement submittal, and was not a party of record. For purposes of our deliberations on revenue requirement allocation, therefore, we will review the testimony presented by parties. We will make reference to statements made by DWR, as relevant, in the context of its use by parties in the evidentiary exhibits admitted into evidence.

Parties' proposals can be categorized into two generally opposing points of view. One group generally favors allocating statewide procurement supplies on a pro rata basis in proportion to the net short position of each utility, except for certain limited utility-specific adjustments. This approach has been generally referred to as a "postage stamp" allocation method. Another group favors allocating discrete costs to specific utility service territories by attributing specific supply sources to specific utilities. ORA offered a third alternative which would average the results obtained from the "postage stamp" and the location-specific cost approaches.

In general terms, the location-specific allocation proposals result in a greater proportion of costs being allocated to PG&E's customers relative to the southern California utilities when compared with the "postage stamp" approach. The effects of these parties allocation proposals in terms of cents per kWh charges are summarized as follows:

Summary of Parties' Allocation Proposals

Pro-Rata ("Postage Stamp") Approaches

Party		PG&E	Edison	SDG&E	Total
PG&E (Ex. 181)	Revenue Reqt ($000)	$4,802,609	$3,608,734	$1,592,118	$10,003,461
	Rate (cents/kWh)	10.126	10.126	10.126	
TURN (Ex. 172)	Revenue Reqt ($000)	$4,765,407	$3,674,066	$1,563,989	$10,003,461
	Rate (cents/kWh)	10.047	10.309	9.947	

Geographically Differentiated Approaches

Party		PG&E	Edison	SDG&E	Total
Edison (Ex. 151-A)	Revenue Reqt ($000)	$4,831,668	$3,825,626	$1,346,167	$10,003,461
	Charge (cents/kWh)	10.187	10.734	8.561	
SDG&E (Ex. 168)	Revenue Reqt ($000)	$5,088,000	$3,593,000	$1,322,000	$10,003,000
	Charge (cents/kWh)	10.727	10.082	8.408	
PG&E (Ex. 181)	Revenue Reqt ($000)	$4,287,022	$4,142,546	$1,573,894	$10,003,461
	Charge (cents/kWh)	9.039	11.623	10.010	

Averaging of Pro-Rata and Geographically Differentiated Approaches

Party		PG&E	Edison	SDG&E	Total
ORA	Revenue Reqt ($000)	$4,973,279	$3,513,501	$1,516,682	$10,003,461
	Charge (cents/kWh)	10.486	9.858	9.646	
DWR Sales (GWh, over 24-month record period)		**47,430**	**35,639**	**15,724**	**98,793**
Percent of Sales		**48.0%**	**36.1%**	**15.9%**	**100%**

Percent of DWR Revenues Allocated to Each Utility

Pro-Rata ("Postage Stamp") Approaches

Proposal	**PG&E**	**Edison**	**SDG&E**	**Total**
PG&E (Ex. 181)	48.0%	36.1%	15.9%	100%
TURN (Ex. 172)	47.6%	36.7%	15.6%	100%

Geographically Differentiated Approaches

Proposal	**PG&E**	**Edison**	**SDG&E**	**Total**
Edison (Ex. 151-A)	48.3%	38.2%	13.5%	100%
SDG&E (Ex. 168)	50.9%	35.9%	13.2%	100%
PG&E (Ex. 181)	42.9%	41.4%	15.7%	100%

Averaging of Pro-Rata & Geographically Differentiated Approaches

Proposal	**PG&E**	**Edison**	**SDG&E**	**Total**
ORA	49.7%	35.1%	15.2%	100%

2. Parties Supporting the Pro Rata Allocation Approach

PG&E and TURN both present allocation proposals based upon variations of the "postage stamp." This general approach was also supported by Aglet, CLECA, and UCAN. Proponents of the "postage stamp" approach support allocation of revenue requirement on a uniform basis proportionate to net short position of each of the utilities. Under this approach, no cost differential is recognized in the allocation on the basis of where a particular source of power supply originates, or from which contract it was procured.

Proponents of the postage stamp approach argue that DWR's purchasing decisions were not driven by differentiating the individual power needs of each utility on a stand-alone basis. DWR did not procure three separate portfolios of supplies, but rather, pursued a statewide purchasing strategy to procure one overall portfolio as a result of a statewide energy crisis. PG&E's witness Kuga testified that because DWR's legislative mandate was to purchase power on a statewide basis, it is reasonable to allocate costs uniformly among the utilities on the basis of their retail net short position (i.e., DWR's retail metered sales). Witness Kuga notes statements made by DWR that any attempted cost allocation by service territory would be "an artifice which would result in an arbirary allocation of costs that would not necessarily result in any more logical or accurate cost causation."[18]

Although PG&E opposes a location-based allocation method in principle, PG&E argues that certain adjustments would be warranted in the event that the Commission adopted such an approach over PG&E's objections.

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[18] Kuga Direct Testimony (Ex 163) p. 1-3, quoting DWR memorandum to CPUC dated August 9, 2001.

The four adjustments PG&E makes to the DWR location-based allocation reflect various ways in which the DWR model may overestimate PG&E allocated costs. The four adjustments are: (1) decreasing the net short purchased to fulfill the Western Area Power Administration (WAPA) contract, (2) accounting for utility self-provision of ancillary services, (3) crediting PG&E with the benefits of operating the Helms pumped storage plant, and (4) eliminating the double counting of unaccounted for energy (Ex.163, pp. 2-8).

While TURN supports a postage stamp allocation approach similar to that supported by PG&E, TURN proposes modifications to recognize certain utility-specific impacts. TURN's proposed utility-specific adjustments are generally similar in principle to the alternative cost-based adjustments proposed by PG&E. Unlike PG&E, however, TURN has incorporated these utility-specific adjustments into its primary pro rata allocation recommendation. TURN's proposed allocation reflects: (1) a slightly changed definition of net short from that assumed by DWR's model; (2) exclusion of pumped storage generation and loads; and (3) a different allocation method for ancillary services to better credit utilities able to self-provide such services.

Aglet and CLECA also presented testimony in support of the postage stamp allocation methodology. Aglet's witness Weil testified that allocation based on equal dollars per mWh is fair and reasonable because: (1) actual flows of electricity over the state's transmission network, and consequently the assignment of costs to individual utility customers, are complex and difficult to predict or measure (Weil, 41 RT 618621-6187:24); (2) DWR contracts have stabilized the power market, to the benefit of all ratepayers; and (3) the State of California's credit quality is superior to that of PG&E and SCE, possibly leading to reduced risk premiums by generators and marketers, which benefit all customers.

The DWR costs also include ancillary services, demand-side management, administrative and general expenses and capital-related costs, financing costs, and potential accrual of cash reserve requirements. Most of the costs and cash flows are not specific to any utility. Witness Weil further testified that the postage stamp allocation will also facilitate similar treatment of off-system sales revenues. Generation need not be dedicated to specific off-system sales customers, and assignment of revenues based on geographic area would be arbitrary. More generally, it is difficult to identify specific DWR contracts and incremental dispatched resources that are meant to serve specific incremental customer loads, even within large areas separated by transmission line constraints. If we were to allow retrospective adjustments to inter-utility cost allocations, the computer modeling required would be difficult and contested. Power flows over constrained transmission systems are very much dependent on ephemeral conditions like weather, ambient temperatures, local loads, and other factors. (Weil, 41 RT 6187:6-24.)

3. Parties Supporting Geographically Differentiated Cost Allocations

SCE and SDG&E each propose variations of an allocation methodology on the basis of the location where the power was procured. SCE and SDG&E translate cost differences associated with power deliveries by location into differences in the cost of providing power to customers in each of the service territories of the three utilities. SCE and SDG&E reject the postage stamp allocation arguing that it is overly simplistic, ignores cost-causation principles, and results in an unfair and economically inefficient allocation of DWR costs among utility customers.

Although SCE and SDG&E differ in their proposals, they each propose to allocate some portion of DWR procurement costs by measuring regional cost differences. SCE and SDG&E each argue that its proposal is consistent with Commission policy favoring the allocation of revenue based on cost-causality principles. SCE notes that the Commission has established the cost of service principle for allocating revenue requirement in the context of rate design for customers of the utility, and argues that there is no reason to allocate costs between utility service territories differently than costs among customer groups within a single utility service territory. SCE and SDG&E argue that failure to allocate DWR revenues based on cost causation principles would be inequitable, discriminatory, and economically inefficient. These principles are set forth in Exhibit 153:

a. SCE's Proposal

SCE proposes that the DWR costs to be allocated be separated into two components for differing allocation treatment. SCE characterizes the procurement costs of DWR fixed long term (90 days or longer) contracts as costs incurred to meet the joint net short position of all three utilities. Because these long-term contracts provided a benefit to the entire State of California by lowering electricity prices on the spot market, SCE proposes that such fixed contract costs be allocated pro rata based on each utility’s net short position. For short-term purchases (less than 90 days), however, SCE proposes that supply costs be allocated between PG&E and southern California utility customers based on the separate zonal cost of supplies using Path 15 as a dividing point.

SCE is in partial agreement with the position of PG&E insofar as it proposes to apply average pro rata costs for long-term contracts without regard to the location of the energy supplies procured for customers of each utility. SCE is in partial agreement with the position of SDG&E insofar as it proposes to allocate short-term power costs separately for utility customers north or south of Path 15, as explained below.

SCE's proposal for the treatment of long-term contracts differs from PG&E's, however, in terms of the level of detail involved in measuring the allocation. To the extent that each utility's net short position varies on an hourly basis and DWR contract costs vary hourly, SCE proposes a proportional allocation of hourly contract costs based on the hourly net short positions of each utility. Revenues from DWR off-system sales would be allocated the same way. PG&E, by contrast, proposes use of only monthly average data for pro rating the allocation.

SCE argues that any allocation of actual energy costs on anything less precise than on an hourly basis would bear little resemblance to costs that are actually incurred for customers of each utility. Because the hourly cost data necessary to make the allocation calculations are not currently available in the record, SCE proposes that the Commission make an interim allocation of revenues on a monthly net short basis for now. SCE also proposes that the interim allocations based upon aggregate monthly sales data have a provision for an after-the-fact true up using the hourly cost data once it becomes available from DWR.

The data that DWR would need to produce in order to provide for an hourly allocation under SCE's proposal is DWR's:[19]

- mWh purchases under long term contracts;

[19] In a memorandum from Peter Garris, DWR's Acting Deputy Director, to Commissioner Geoffrey Brown, dated November 28, 2001, DWR committed to providing the hourly cost information to the Commission on a timely basis.

- average hourly long term contract costs;
- short-term mWh purchase prices in NP 15 and SP 15; and
- short-term hourly purchase prices in NP 15 and SP 15.

SCE also proposes that other miscellaneous DWR costs that do not vary with energy consumption or by time period, (e.g., A&G, DSM, and financing-related costs) are appropriately allocated on a monthly basis in proportion to each utility's net short position.

SCE draws a distinction between long-term contracts where the delivery point is irrelevant for allocation purposes and short-term power purchases to meet the residual net short position of each utility once long-term contract power purchases have been allocated. SCE views this second category of costs as being incurred in separate zones to meet specific utility needs in those zones. As such, SCE argues, the location of the related short-term power purchases becomes a relevant consideration for allocation purposes.

SCE's witness Stern acknowledges that in most instances, the costs associated with meeting these residual net short needs will not vary by location. But the price of power within northern California versus southern California will be different if a transmission constraint exists. When transmission constraints exist, SCE recommends that DWR costs of short-term and spot purchases be allocated separately for areas north and south of Path 15. Under this zonal allocation approach, contract costs for power delivered into the transmission grid in zones north of Path 15 are assumed to be 100% attributable to PG&E customer loads. Only the amount of power north of Path 15 in excess of PG&E loads is assigned residually to utility customers located south of Path 15.

SCE's distinction between unavoidable and shorter-term costs is based on the principle that "[t]he entity causing DWR to incur a cost should pay that cost." (Exhibit 150, SCE's witness Gary Stern, p. 1, line 7.) SCE assumes that: (1) DWR incurs long-term costs to meet the combined needs of all utilities, and (2) during times of transmission constraints, zonal power displaces each utility's URG. (Exhibit 150, Stern, p. 3, line 21.)

SCE also believes that each utility should be responsible for the share of DWR's ancillary service costs that it causes. Each utilty's share of allocated costs would thereby be directly reduced by the amount of such costs that it provides for itself. To the extent there is congestion in real time causing a price difference between zones for ancillary services, SCE proposes that the allocation be done on a zonal basis, with separate allocation on an hourly cost basis.

b. SDG&E's Proposal

SDG&E agrees with SCE in its emphasis on cost causation as an important principle to apply in allocating DWR costs, but differs with SCE on how those principles should be applied here. SDG&E supports allocating all DWR procurement costs on a zonal basis, irrespective of whether they relate to fixed contracts or short-term purchases. In this respect, SDG&E differs with SCE that at least the fixed contract costs serve the joint needs of all three utilities, and thus should be allocated on a statewide pro rata basis without regard to supply zone. SDG&E states that it did not have the data nor the time necessary to develop a comprehensive DWR revenue allocation proposal based on cost causation principles. However, SDG&E claims that the methodology developed by the Commission's Energy Division as reflected in the ALJ's Draft Decision moves the Commission as close as possible to a cost-based allocation under the circumstances.

As incorporated in the ALJ's Draft Decision, the Energy Division derived an allocation of the DWR revenue requirement, differentiated between whether the energy is delivered over facilities in northern California or in southern California. As the geographical dividing point, the Energy Division used Transmission Path 15. Energy sources procured north of Path 15 were allocated to PG&E customers. Energy sources procured south of Path 15 were allocated to customers of SCE and SDG&E. SDG&E argues that the Energy Division method recognizes that differences exist in the cost to serve consumers in different parts of the State. SDG&E advocates the use of this method, arguing that the Commission cannot wait for a full-blown cost allocation study recognizing all relevant cost differences and constraints, for which there is neither the data nor the time to implement.

SDG&E proposes certain adjustments to the Energy Division allocation methodology, to provide what it considers to be a more accurate allocation result. First, SDG&E's proposed allocation reflects a price differential of electric energy supplies between the NP 15 and SP 15 regions. The adjustment, presented in Exhibits 155 and 157, would result in a shift in cost allocation from southern to northern California, the supporting calculations of which are set forth in (confidential) Exhibit 158. SDG&E's witness Nelson (Ex. 157) computed a revenue requirement reduction of approximately $186 million in SDG&E's share of the DWR allocation as a result of the price differential between NP 15 and SP 15 for the period January through July 2001. SDG&E assigns the higher NP 15 prices to PG&E customers on the premise the power associated with the higher NP 15 prices was consumed exclusively by PG&E customers. SDG&E's witness Nelson testified that one of the principal causes of the price differential was the congestion charge assessed by the ISO on the north-to-south power flow. For periods when no congestion existed on Path 15, prices were the same both for NP 15 and SP 15.

As a second adjustment, SDG&E recalculates the net short allocated to SDG&E customers for February and March 2001. The DWR PROSYM model allocates 14% of DWR's purchases to SDG&E for February and March 2001. DWR, however, later presented data that the correct percent of DWR's purchases during those months was 12%, not 14%, resulting in $51 million more being allocated than should be to SDG&E's customers. (Exh. 155, p. 4.) Although the difference in percentage is small, SDG&E argues that the amount at issue is significant because DWR's costs for power during this period averaged $269/mWh, higher than any other quarter. (*Id.*) SDG&E argues that its customers did not cause DWR to incur this cost and therefore should not be allocated that cost.

SDG&E makes a third adjustment for the lead/lag accrual to cash which accounts for the timing difference between the provision of services and the receipts of cash for them. In its August 7th update, DWR erroneously attributed to SDG&E customers certain purchases made in January 2001. When DWR corrected this in its November 5th filing, SDG&E claims the effect was to *increase* the revenue requirements to its customers. During January, DWR incurred substantial expenses but had not received any revenue in order to pay for them. This resulted in a large lag in accrual to cash in January, reducing revenue requirements in January that DWR allocated based on retail sales. Since DWR did not have any retail sales to SDG&E in January, SDG&E did not share in that reduction.

In later months, DWR's cash payments exceeded its accrual, resulting in a lead in accrual to cash. In those months, that added to DWR's revenue requirements and SDG&E's customers bore part of that addition. The net effect to SDG&E customers was an added cost due to their not sharing in the January lag (reduction to revenue requirement) but bearing part of the subsequent leads (increased revenue requirement) that were caused by the other utilities. SDG&E proposed to adjust for this net effect in order to avoid SDG&E's customers being allocated revenue requirements that they did not cause. SDG&E calculates a $65 million credit to the revenue requirement allocated to its customers due to this adjustment. Exh. 155, pp. 4-5.

SDG&E's proposal differs from SCE's in terms of the importance that SDG&E places on forecasted (i.e., ex ante) costs, as opposed to actual costs for allocation purposes. SDG&E argues that allocations fixed long term contract purchases should rely upon ex ante sales forecasts provided to DWR by the utilities, and that such allocations should not be trued up for actual sales. SDG&E argues that because DWR made purchase commitments based on the sales forecasts provided by the utilities, each utility should bear responsibility for the allocation of costs that results from DWR's use of such forecast. SDG&E further proposes that variable price or spot (imbalance) purchases should be allocated based on actual consumption relative to what was purchased under the fixed contract, and that gains or losses from sale of surplus energy should be allocated based on the same differential between forecast and actual consumption.

SDG&E acknowledges that certain types of DWR costs (e.g., overhead and A&G) cannot be attributable to specific service territories. SDG&E does not oppose such costs being allocated to consumers on a uniform statewide pro rata basis.

4. ORA's Proposal

ORA recommends the Commission allocate DWR costs by using a simple average of what it characterizes as the most conservative versions of the postage stamp model and the Energy Division's cost-based model (Ex. 161,

p. 1-2). ORA argues that such an average will capture the relative strengths and weaknesses of both models. An average acknowledges different regional costs, but also biases cost responsibility toward the assumption that DWR's primary concern was to satisfy a statewide need. ORA believes that the evidence supports both assumptions. An average also reflects ORA's belief that a "cost-based" method is conceptually more accurate and appropriate than a postage stamp method. At the same time, an allocation average of the two methods reflects and acknowledges the lack of necessary information needed to develop an accurate cost-based allocation.

ORA's method utilizes utility specific input data from the DWR revenue requirements model in a manner similar to that described in the September 4 Draft Decision. ORA extracts data from the PROSYM input model runs made by DWR in an attempt to obtain DWR costs by utility in order to display different spot prices for PG&E and SCE are attributed to transmission constraints. However these PROSYM input results do not match the actual DWR energy bill in 2001 or the expected energy bill in 2002. To obtain the energy bill which DWR estimates has actually occurred to date and forecasts for 2002, these model run results have to be increased. The average revenue increase required for 2001 is 26%, for 2002 the estimate is an 8% increase. ORA therefore simply increases the number the PROSYM input results for each utility by 26% in 2001 and 8% in 2002 to correspond to DWR's estimate of required energy revenues. In addition ORA assumed a 7.43% percent increase to cover ancillary services applied uniformly to all three utilities following DWR's assumptions.

Another allocation option suggested by ORA is for the Commission to adopt a postage stamp allocation for 2001, and to adopt a zonally-based allocation for 2002. ORA believes this averaging effect would also provide appropriate dispatch signals for the utilities' own retained generation decisions.

Of course, this assumes real time communication between DWR and the utilities regarding the price of DWR's hourly purchasing opportunities.

C. Discussion

1. Statutory Basis for Allocation Methodology

We first address the contention of certain parties that AB 1X, Water Code Section 80002.5 mandates a postage stamp allocation method by law. The pertinent language reads:

> "It is the intent of the Legislature that power acquired by the department under this division shall be sold to all retail end use customers being served by electrical corporations...Power sold by the department to end use customers shall be allocated pro rata among all classes of customers to the extent practicable."
>
> Cal. Water Code Section 80002.5 (emphasis added).

We do not interpret the statute as requiring any particular revenue allocation approach as a matter of law As noted by SCE and SDG&E, the statute addresses how *power* sold by DWR is to be allocated, but does not prescribe how DWR's *revenue requirement* is to be allocated. Allocation of *power* on a pro rata basis relates to physical deliveries of mWhs, and simply means that DWR has to supply all customer classes with power on pro rata or proportionate basis (e.g., not giving residential customers priority and curtailing industrials, or vice versa.) Also, this section addresses allocation *among all classes of customers,* not allocation among service areas. Furthermore, "to the extent practicable" recognizes that there may be practical reasons why DWR must allocate power (not costs) differently among classes of customers (not service areas). Accordingly, we shall determine the allocation of revenue requirements based upon the merits of the factual record, rather than relying merely on a legal interpretation of the statute.

2. Cost-Based Principles as a Basis for DWR Allocation Methodology

This Commission has traditionally recognized the principle that utility revenues should be allocated by assigning cost responsibility in relation to cost causation. Cost-based rates promote economic efficiency because customers pay for what they consume, and thus properly adjust their consumption to match what the product really costs (Ex. 153, p. 6). SDG&E Witness Croyle notes that cost causation and cost allocation principles are "standard fare" for the utilities and not a new idea. (Ex. 153, pp. 11-12). Cost-based allocation and rate design promotes efficient utility planning.

SCE's witness Stern adds that not allocating spot energy purchases to utilities' service territories on a cost basis gives false signals to the utilities on how best to dispatch their own resources. For example, if the costs allocated to its service territory are higher than actual cost, the utility might erroneously dispatch one of its own resources that is less expensive than the allocated cost, but more expensive than the actual cost, which is not an economically efficient practice (Ex. 151, pp. 14-15). However, Dr. Stern agrees that allocation decisions made now for sunk costs, those already incurred by DWR during 2001, has nothing to do with economic efficiency (Stern/SCE, RT 5854). Croyle further argues that, had the DWR not been purchasing power on behalf of the utilities, the utilities would have had to face the market themselves and been exposed to all the factors that cause regional differences in pricing (Ex. 153, p. 7). SDG&E argues that the costs the DWR incurs should not be allocated on a different basis just because DWR is an interim provider

We agree that the cost allocation principles adopted for DWR revenues should reflect the cost that the customer imposes on the system. The more difficult question is how to implement an allocation that best achieves that objective. In D. 96-04-050 which decided revenue allocation and rate design issues in SCE's general rate case, the Commission stated:

> "[W]e reiterate our primary goal of ratemaking, namely, to achieve rates which reflect the cost that the customer imposes on the system. This approach not only results in an equitable distribution of [SCE's] revenue requirement, but also provides the most accurate price signals to the customer regarding his energy consumption."

In D.96-04-050, cost causation principles were applied to compute marginal costs in the context of allocating revenues between different customer classes and designing rates within a single utility's service territory. In this proceeding, however, we face just the opposite situation. We are not allocating DWR revenues based on customer class distinctions nor designing retail rates. Rather, we are allocating revenues in the aggregate among three different utility service territories.

We agree that cost responsibility should be assigned in relation to those factors that cause the costs. We also agree that DWR revenues should be assigned on the basis of cost causation to the extent that clear drivers of cost can be identified and measured. Yet, in order for a cost-differentiated revenue allocation to be applied separately among the three utilities, there must be a discernable cause-and-effect relationship between the cost incurred and a cost driver.

SDG&E and SCE portray the choice of allocation methods before us as a dichotomy between either cost-based (i.e., the SCE/SDG&E approaches) or non-cost based (i.e., the PG&E/TURN approaches). We disagree with such a characterization of the alternative proposals. We view all of the allocation alternatives presented by parties as forms of cost-based allocation. The differences relate only to *how accurately* the proposed cost drivers under the alternative proposals reflect cost causation, not *whether* cost causation is an appropriate standard.

The proposals to allocate costs pro rata to each utility merely represents another form of cost-based allocation where the cost driver is the net short position of each utility. The share of costs assigned to each service territory differ in relation to the size of the net short. Thus, under all the proposals, including the pro rata allocation alternatives, the greatest portion of DWR costs is allocated to the PG&E customers, reflecting the fact that the largest portion of net short power procured by DWR is sold to customers in PG&E's service territory. None of the parties propose that the Commission apply an allocation approach that intentionally subsidizes a particular customer group, nor one that allocates a profit premium to certain customers beyond the straight cost incurred by DWR.

3. Allocation of Administrative and Financing Costs

Parties generally agree that DWR administrative and financing costs cannot reasonably be attributable to specific customer groups, and may be allocated on a statewide pro rata basis in relation to the net short position of each utility. These costs include administrative, DSM, and financing costs. Recognizing that there is essentially no dispute over the allocation of such miscellaneous costs, we shall allocate such costs on a statewide pro rata basis in relation to each utility's net short position.

4. Allocation of Power Procurement Commodity Costs

We next turn our attention to the dispute over the allocation of DWR's commodity costs associated with procurement of power. The dispute centers on whether costs of power supply sources in northern California (NP 15) are separately attributable to customers in PG&E's territory, or whether all utility customers statewide should be assigned a pro rata share of those costs. To determine whether the costs of specific sources of supplies incurred in northern California should be exclusively allocated to PG&E customers based on cost causation principles, we must determine whether a cause-and-effect relationship exists between these costs and the use of energy exclusively by those customers.

a. Supply Portfolio Criterion

One ideal measure of cost causation in relation to the three separate utility service territories would be evidence that DWR had actually procured separate portfolios of supplies specifically targeted toward each respective utility's customers. If DWR had expressly procured a separate portfolio of supplies for each utility service territory, there would be a strong cause-and-effect relationship between location of supplies and specific utility service territory served.

This, in fact, did not occur. As noted by DWR, itself: "DWR has had minimal flexibility in its choice of power providers. Therefore, it has not been possible for DWR to undertake separate solicitations for each of the IOU service areas."[20] SDG&E Witness Croyle agreed in cross-examination that the DWR contracted for electricity on behalf of all three utilities and did not conduct separate solicitations for the three service areas (Croyle/SDG&E, RT 5997 and 5998). TURN witness Marcus concluded that, based on his reading of every long-term contract, DWR "was basically trying to do anything it could to alleviate problems for the summer of 2001 and, to a lesser extent, 2002, in the period from February through May…they were trying to get anything they could

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[20] See Ex. 163, p. 1-3; quoting DWR memorandum to the CPUC, August 8, 2001; Response to Comments on DWR Revenue Requirements, P. 3.

get."[21] DWR itself has stated that its service territory is "statewide. The energy associated with the net short contracts is not directly assigned to the IOUs or to a specific area."[22]

DWR thus has not maintained separate portfolios to meet the net short positions of each utility. Any allocation of power purchased under the DWR contracts and spot market purchases for each respective service area by assuming distinctly separate sources of supply for each utility is not consistent with the way DWR constructed its portfolio of supplies, and would not necessarily result in any more logical or accurate cost causation than a statewide pro rata approach.

b. Transmission Congestion Criterion

In the absence of separate portfolios, we must consider whether any other factors resulted in different prices being incurred for energy delivered to customers in each of the three utilities' service territories. As noted by CLECA Witness Barkovich, electricity that is bought on behalf of a group of customers that flows through the same grid should, under the laws of physics, be available to all of those customers that are served off that grid, unless transmission congestion prevents that occurrence.[23]

SDG&E and SCE point to transmission congestion over Path 15 as a constraining factor causing DWR to procure supplies delivered north of Path 15 specifically for northern California customers (i.e., the PG&E service territory).

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[21] See 43 RT 6371-6372/Marcus.

[22] See Ex. 163, pp. 1-2; footnote 2.

[23] Ex. 159, Barkovich Testimony; pg. 8.

SDG&E argues that because DWR assumed the transmission system would be congested, it therefore made purchases north and south consistent with that assumption. DWR's response to data request PG&E-8, cited in Exhibit 157 (p. 3) stated that there is "no factual basis" for assuming that transmission constraints do not exist.

There is general agreement that during the first few months of 2001, a price differential existed between power to be delivered north of Path 15, and power to be delivered south of Path 15. However, parties disagree as to whether DWR paid the differential exclusively due to servicing PG&E load demand.

SDG&E argues that north-to-south transmission constraints caused pricing differentials that represent a major cost driver relevant to the DWR allocation between northern and southern service territories which justify its proposed $186 million reduction in costs allocated to its customers. SDG&E acknowledges a difference in the size of the price spread between the public data cited in Nelson's testimony and the confidential data in his workpapers.[24] However, Nelson's workpapers (Ex. 158) reflect the costs that DWR actually incurred in buying power in the northern and southern zones. The public data only was provided only to illustrate the market environment in which DWR operated, since the confidential DWR data could not be made public.[25]

Witness Croyle claims that the DWR could not possibly have ignored the cost differences imposed by the transmission constraints along Path 15, and had to ensure that each region would have enough electricity when the transmission constraint is operative. SDG&E claims that DWR acknowledges

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[24] See, 41 RT 6126, lines 2-9 (and earlier comments on 6125.)

[25] See, Exh. 157, 41 RT 6105, lines 5-15.

making purchasing decisions on the basis of this split between North and South. In response to Data Request SCE-01, DWR listed various procurement objectives under AB 1X, and stated: "These objectives include, but are not limited to, the following…Match intrastate regional electric needs (north and south of Path 15 transmission constraints) to locations of supply." [26] SDG&E thus argues that it is both factually correct and reasonable to recognize Transmission Path 15 as a "geographical dividing point" for allocating costs. SCE Witness Stern likewise testified that in times of actual transmission constraints on Path 15, DWR was forced to purchase power in the zone north of Path 15.[27]

We find no basis in the record to assume that actual transmission constraints were constant over time, or that the physical flow of power delivered into the grid from NP 15 sources was exclusively consumed by northern California customers of PG&E. Presumed NP 15/ SP 15 transmission constraints at times were only anticipated to occur, but did not ultimately materialize. PG&E Witness Kuga testified that at times, congestion was anticipated in pricing power in the day-ahead market, but in real time there was no congestion. Thus, actual power flows over Path 15 could and did physically flow north to south. DWR may have purchased power in one zone at a higher price than in the other zone even when there wasn't an actual transmission constraint, but where one was expected. That is, real price differentials could occur simply based on the expectation of congestion, even if that congestion fails to materialize. This has been referred to as "phantom congestion."

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[26] See excerpt from DWR's response to SCE's Data Request SCE-01, as cited in Exhs. 155 and 157.)

[27] SCE, Stern, 39 RT 5902.

Therefore, the payment of a price differential for NP 15 power did not always equate to a physical constraint preventing NP 15 power flows to SP 15 destinations. Moreover, while one of DWR's objectives was to "match regional electric needs to locations of supply," there was no strict division segregating the source of deliveries to PG&E versus to southern California customers. DWR states that in fact, "energy associated with the net short contracts is not directly assigned to the IOUs or to a specific area." [28] To the contrary, DWR stated that "power purchased under many contracts will in fact be used to meet the net short in more than one service area, directly or through swaps, exchanges or otherwise. The allocation of power will change continually over time."[29]

Therefore, the existence of a price differential for congestion charges over Path 15 does not form the basis for any specific identification of supply sources with specific territories served. Similarly, even where transmission congestion constrained north-to-south deliveries, DWR might still be able to arrange a power exchange with other SP 15 supply sources to provide the benefits of NP 15 supplies to SP 15 customers.

Moreover, Path 15 does not, in fact, represent a boundary between PG&E and SCE, but rather falls within PG&E's service territory. Furthermore, sometimes the zones are separated by congestion on Path 26. [30] Thus, even if we agreed in principle that costs should be allocated based on a strict north-to-south

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[28] See DWR's Response to PG&E Data Request 34, as referenced in Ex. 163, footnote 2.

[29] See DWR's Response to Data Requests dated August 1, 2001, as cited on page 10 of CLECA Ex. 159.

[30] See Ex. 159 (Barkovich) pg. 4 footnote.

transmission boundary, the measurements offered by SDG&E and SCE based on Path 15 would not be congruent with PG&E's service territory. The SCE/SDG&E approach would arbitrarily allocate the higher NP 15 costs even to those PG&E customers residing south of the Path 15 transmission constraint.

SDG&E argues that whether or not the system *was* constrained becomes moot in terms of cost causation since the cause of purchases north and south of Path 15 was an *expectation* of system constraint and inability to move purchases north and south. To the extent the congestion was phantom in nature, it indicates at least from a physical perspective, that powers sources procured in NP 15 locations could and did flow south for consumption by SCE and SDG&E customers. The only remaining question is whether the NP 15 price differential associated with the expectation of system constraint was attributable exclusively to PG&E customers, even where the actual flow of power was not constrained to the north.

Transmission constraints that limit service from specific generators to incremental customer loads, for example temporary Path 15 constraints, are unstable over time. Power flows over Path 15 when the line is constrained depend on weather conditions, and transmission constraints on Path 15 are not in effect all the time. Thus, attempting to model transmission constraints as a variable in DWR cost allocation would result in volatility, and unfairly magnify the price adjustments on utility ratepayers.[31]

Moreover, higher prices paid by DWR for power delivered into the transmission grid north of Path 15 that were paid during the early months of 2001 might have been caused in part by other factors besides just congestion,

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[31] See Ex. 160, Weil Testimony, page 4.

exclusively. For example, various contract prices DWR agreed to are a function of *when* DWR signed the contracts rather than *where* the power was ultimately consumed. Prices are also a function of the structure of the contracts, for example whether they include a separate capacity component, are indexed to natural gas prices, or call for delivery only during specified times of the day. Prices can be a function of the term of the contracts, as well. SDG&E and SCE did not adjust out such extraneous factors, but simply assumed the entire price differential was due to transmission congestion and thus assignable only to PG&E customers. No party presented evidence on the extent to which factors other than transmission congestion contributed toward the higher price of NP 15 power.

We conclude that the causes of the price differential cannot fairly be attributed exclusively to customers in the PG&E service territory. As noted by PG&E, we agree that congestion costs were a reflection of a statewide dysfunctional market during the early part of 2001, rather than a product of the physical configuration of the system. After FERC adopted measures to help minimize or eliminate the market flaws in California, the pricing across Path 15 changed substantially. Price differentials between north of Path 15 and south of Path 15 power have been diminishing, or have practically disappeared. Witness Nelson testified that New York Mecantile Exchange prices for 2002 deliveries suggest that NP 15 prices might be lower than SP 15 prices in the future.[32]

To the extent that flawed market rules were due to statewide dysfunctionality of the market, the impacts of those rules cannot reasonably be isolated only to one geographical sector of California consumers. This finding is

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[32] Ex. 157, p. 4.

consistent with D. 01-05-064 where we stated that "no customer is causing the exorbitant electricity prices faced by the utilities and CDWR. Thus, it would be unfair to attribute the current wholesale market prices as caused by any particular type of customer….The price of wholesale energy bears no relationship to the cost of production, but is rather a function of what price can be extracted from the California market through manipulation." [33]

In the same way that we cannot attribute dysfunctional price increases to particular customers, by virtue of their type, likewise, we cannot attribute such prices increases only to certain customers, simply by virtue of their location. Therefore, while PG&E customers certainly should absorb some share of the NP 15 congestion charge differential, they should not shoulder the entire burden. The statewide pro rata approach to allocation fairly assigns a share of these costs among all ratepayers.

Even if theoretically, the costs of supplies that were used to serve PG&E customers were systematically higher than for southern California customers, the underlying data to compute cost differentials is unreliable. Development of differential allocation methods has been impeded by the difficulties faced by parties in gaining access to modeling information, including the PROSYM input data set that underlies the DWR model.

SDG&E's witness Mr. Croyle admits that the quality of the data is less than optimal, but believes that his proposed allocation moves toward a cost basis that is more robust than alternative methods (Ex. 153, pp. 2-3). CLECA witness Barkovich testified that it is not possible for other parties to verify the results of DWR's modeling efforts, which are a function of unverifiable input

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[33] D.01-05-064, *mimeo*, pg. 18

assumptions and the algorithms contained in the model. The production of locational prices, the aggregation of these prices to ISO congestion zones, and the connection of these zones to the service areas of the three utilities are all open to question (Ex. 159, p. 3-4).

In view of unexplained shifts in DWR's forecast, Barkovich questions the reliability of the underlying forecasting methodologies as a basis for allocating costs on a region-specific basis For example, DWR forecasted huge spot energy price differences as high as 4 to 1 between PG&E and the two southern utilities forecasted for early 2002 in its original workpapers. Yet, in DWR's latest workpapers, this differential has been eliminated for 2002. PROSYM models energy deliveries and constraints. But no party knows how the modeling occurred, so PROSYM results simply represent a "black box". Thus the most critical element of cost-based treatment – regional constraints and planning - is unknown.

The use of a uniform pro rata allocation approach on a statewide basis is also consistent with how DWR's production cost model works. DWR uses the PROSYM production cost model to simulate the operation of the western regional electric system, and to estimate DWR's total power purchase costs to serve a single statewide service territory. DWR has also developed a financial model which takes output from PROSYM and determines DWR's needs for utility customer revenues on a statewide basis, taking into account estimates of purchase volumes, ancillary services, and financing costs.[34]

[34] See Ex 163, p. 2-3.

Thus, we are unpersuaded that the price differentials across Path 15 as computed by SDG&E can reasonably be attributed as higher costs to serve only PG&E customers to the exclusion of southern California utility customers.

Because any price differential between DWR's costs for power delivered north of Path 15 and for power delivered south of Path 15 was likely to have been the consequence of dysfunctional statewide market rules, there is insufficient basis to allocate a disproportionate share of NP 15 costs to PG&E customers based on the theory of cost causation.

c. Distinctions in the Allocation of Fixed Price Versus Short Term Purchases

We find no objective basis to apply different allocation methodologies based merely on whether a cost relates to a long term fixed price or a short term purchases, as proposed by SCE. SCE witness Stern testified that "[DWR] did not distinguish the delivery location in their process of procuring those long-term contracts." SCE distinguishes, however, between (a) long term contracts used to serve the joint needs of all customers with no regional differences and (b) short term power purchases presumed to meet the separate needs of each utility from distinctly different sources of regional supply.

From an operational perspective, however, we find no special significance in contract duration as a criterion for determining how much power DWR procured for each separate utility service territory. There is no evidence that DWR's intentions regarding service territory deliveries are different depending on whether the source is contract power of less than 90 days duration or long term contracts. (Weil, 41 RT 6179:13-24.) There is no record information about the shorter term contracts. (Barkovich, 41 RT 6141:28-6142:2.) SCE witness Stern acknowledged that DWR has not provided any information associated with the specific reasons for entering into individual short term contracts, for example, whether DWR was motivated by transmission constraints or price factors, for example. (Stern, 39 RT 5864:25-5865:14) Moreover, to the extent URG resources were fully committed, then DWR short term power would not substitute for URG power. Instead, it would replace some other resource or simply increase reserve margins.

Observations as to the pattern of DWR's purchasing mix between short and long term purchases over time lend support to the conclusion that there was no distinction in the destination of power based on the contract term. DWR purchased only shorter term electricity products during the first three months of 2001, then began incurring long term contract costs in April 2001.[35] Therefore, under SCE's proposal, all DWR costs during transmission constrained periods in January, February and March 2001 would be allocated zonally, and most would be allocated zonally until late in the year.

In the first few months of 2001, however, DWR was "scrambling" to obtain whatever resources were available in order meet its procurement goals. (Barkovich, 41 RT 6164:11-22.) DWR's shorter term costs began to decline after April 2001, and ancillary services costs declined significantly during the summer months. (Stern, 40 RT 5966:7-5967:11.) By autumn of 2001, long term contract costs comprised a larger share of DWR's total purchases. The percentage of DWR's long term contract costs overtook that of shorter term purchases in September 2001. (Weil, 41 RT 6193:16-22; see also Exhibit 151-A, Stern.) While DWR's shorter term purchases in the early months of 2001 had different terms

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[35] See Exhibit 151-A, Stern; the exhibit is confidential, but the cited fact is not. (See Stern, 40 RT 5966:7-10.)

than later long term contracts, but they served a similar purpose in supplying the joint needs of the customers of all three utilities. (Weil, 41 RT 6190:26-6191:23.)

Accordingly, we find no basis to allocate the fixed and short term purchases of DWR on different bases. We shall therefore apply a pro rata statewide average allocation basis to DWR's revenue requirement in relation to the net short position of each utility, with adjustment for the utility-specific impacts that have been proposed by TURN, as noted in Section f. below.

d. Allocation Based on Monthly Versus Hourly Cost Data

SCE has proposed that the DWR revenue requirement be pro rated based upon cost data disaggregated into hourly increments. Since hourly DWR cost data is not currently available to parties, SCE proposes an interim allocation based upon monthly net short data, with provision for a true-up using hourly data once DWR makes it available. SCE argues that anything less precise than hourly data will not provide for an accurate allocation of costs.

PG&E opposes the proposal for hourly allocation of data, arguing that it is too administratively complex and burdensome, and offers only a false sense of precision. The use of hourly cost data would entail maintaining 720 separate hourly cost reports per month. PG&E claims that if the hourly data is not well maintained, the cost allocation controversies over the hourly data will be endless.

SDG&E agrees in principle with the goal of precision that SCE seeks to achieve with hourly allocation. SDG&E questions, however, the practicality of implementing an hourly allocation given the complexities involved. SDG&E witness Croyle also observes that if all load in a block contract is priced at the same price in every hour, it is not necessary to allocate costs across the individual hours. The same result is obtained by allocating the cumulative energy among the utilities in aggregate.[36] PG&E likewise argues that hourly data would not provide a true reflection of cost causation for that hour because contracts typically use an average price for power provided across several hours of a day, perhaps for many days across months, seasons, and even years. In instances where a contract price averages the on peak and off peak prices, the average hourly price in the contract causes on-peak costs to be understated, and off-peak costs to be overstated. Thus even an hourly allocation approach would not capture the true avoided costs for each on-peak or off-peak hour, and the resulting hourly allocations would not give an accurate picture of actual hourly cost causation. Furthermore, PG&E argues that such an hourly allocation would not send price signals that could be relied upon to ensure efficient statewide dispatch of power resources.

In theory, we agree that the use of hourly cost allocations could provide more precise measures of cost causation as a basis for revenue allocation as contrasted with monthly cost data. Even if the hourly prices in DWR's contracts may be constant over several hours or reflect an average of on peak and off peak avoided costs, an hourly allocation would still more accurately correspond the net short position of each utility which varies on an hourly basis. An hourly weighting of the each utility's net short position would provide a more precise weighted average for cost allocation than would a monthly average. Although DWR has expressed a willingness to provide the requisite data needed to make the necessary hourly allocations, the data has not been provided for the record at this point. Accordingly, it remains uncertain as to how problematic it would be to obtain the necessary hourly data by each utility, and to agree upon

[36] SDG&E, Croyle, Tr. Vol. 40, p. 6003.

its accuracy and reasonableness. We are not persuaded at this time that an adequate case has been made that the potential administrative complexities, litigiousness, and burden associated with an hourly cost allocation are offset by the potential for more precise measurement of cost causation in allocating DWR revenues.

Accordingly, we shall not make a final judgment regarding the use of hourly cost data for allocation purposes for future DWR allocation proceedings. We shall provide SCE or any other party the opportunity to make a further showing in the next DWR update proceeding. By that time, hopefully, DWR would have made available the requisite data, and parties will be able to provide a more empirical analysis about the practicalities of performing hourly-based allocations. For purposes of this order, we shall use monthly data for determining the allocations, but shall leave open the possibility of allocating DWR costs based on hourly data in the event we subsequently determine to use such data in a future proceeding.

e. ORA's Averaging Approach Criterion

We decline to adopt the averaging of two mutually contradictory approaches proposed by ORA for allocation purposes. Although ORA seeks to incorporate the purported advantages of two opposing allocation methods, ORA also imports the attendant disadvantages of each method. Moreover, ORA's method further complicates the issue by introducing a new allocation variable, namely, the percentage of weighting to assign to each of the two opposing methods that ORA uses. ORA provides only an anecdotal comparison of the relative merits of the two methods, but offers no quantitative rationale why a 50/50 weighting of the two alternatives is preferable to a 25/75 weighting, or some other weighting. Because ORA provides no basis to conclude that the comparative net advantages of each of the two methods are equivalent, its 50/50 weighting appears to be arbitrary. We conclude that whatever method is adopted, it should be based upon a consistent set of allocation principles and assumptions. ORA's method does not fit this criterion. We therefore decline to adopt it.

f. Adopted Allocation Methodology

In view of the various criteria considered above, we conclude on balance, that the pro rata statewide allocation approach offers the most objective, equitable, and economically defensible methodology. Both PG&E and TURN have offered different allocation calculations based generally on the pro rata (postage stamp) approach to allocation. Of these two proposals, we conclude that TURN's is preferable in that it takes into account certain utility-specific adjustments that reflect more specifically the costs related to each utility. No party provided persuasive arguments as to why those adjustments should not be adopted. We find those adjustments promote a more cost-based allocation and reflect cost causation. Accordingly, we adopt those adjustments.

(1) Total Net Short Versus Retail Net Short

TURN proposes an adjustment to provide for a more consistent definition of net short between recorded versus forecasted costs. The DWR model calculates net short on a recorded costs basis reflecting the total net short, but omits certain components to derive something closer to a retail net short on a forecasted cost basis. In particular, DWR's definition of retail net short excludes two items included in the total net short: line losses and PG&E's purchases on behalf of WAPA.[37] TURN argues that for the sake of consistency, total net short

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[37] Marcus Direct Testimony (Ex. 169), pp. 6-7.

should be used to allocate the DWR revenue requirement for the entire period, rather than using total net short for part of the period and retail net short for the remainder.[38] DWR assumes that losses are different among the three utilities in its calculations of total utility load and total net short. By using retail net short, the DWR's postage stamp method prevents these differences from being considered in the cost allocation.[39]

In particular, TURN is concerned that DWR has not properly treated the WAPA-PG&E contract. DWR's use of retail net short would allocate to other utilities the costs which PG&E incurs to serve WAPA.[40] This is inconsistent with the specific terms of the WAPA contract. The contract is treated as part of PG&E's retail customers' obligation as an ongoing purchased power contract. Prior to restructuring, it was included as a retail cost in PG&E's ECAC proceedings. During the transition period under AB 1890, the contract has been included as a purchased power cost in PG&E's TCBA accounts. In other words, PG&E's retail customers buy the power to serve WAPA and receive the revenues from WAPA (which do not cover the full cost of the power that is purchased). In short, TURN argues, WAPA is a PG&E retail contract, and

[38] 43 RT 6369, witness Marcus.

[39] In making this point, TURN is not stating that it specifically agrees with the loss factors used by DWR; rather, that if those different loss factors are used as part of the load forecast that underpins the DWR revenue requirement, then they should also be included in the load forecasts used to allocate costs among the utilities. Any differences between actual and forecast losses would be captured along with other differences in load, when truing up each utility's cost responsibility.

[40] Ex. 169, p. 6.When he appeared to testify in support of his prepared testimony, Mr. Marcus noted that DWR may have fixed this problem in its November 5, 2001 presentation of revenue requirement and inter-utility allocation. 43 RT 6374-75.

therefore any calculation of retail net short for PG&E should not reflect any adjustment for WAPA.

We agree that TURN's adjustment leads to a more consistent definition and application of net short. We shall therefore adopt TURN's proposal to use use total net short (subject to the further adjustments described below) to allocate DWR costs among utilities.

(2) Helms Plant Adjustment

TURN proposes an adjustment to recognize the role of PG&E's Helms Pumped Storage Plant in providing the proper economic incentives to maximize overall efficiency. A pumped storage generation resource, such as Helms, is a net consumer of energy due to the inefficiency of pumping. The underlying premise is that by consuming electricity during off-peak periods when it is relatively cheap, then producing electricity during peak periods when it is relatively expensive, there is a net benefit to the plant's operator and, by extension, to the ratepayers bearing the operating costs in regulated rates.

The underlying premise has been undermined, at least since January 17, 2001. PG&E continues to use off-peak energy to pump Helms in order to generate during on-peak periods. However, the utility is charged the full average net short rate as the cost of the off-peak energy, as well as the on-peak energy. The result is that the economic signals associated with operating the plant are skewed, and ratepayers are required to pay excessive amounts associated with the plant's operations. Under the current conditions, PG&E's ratepayers would be better off had the Helms plant not been used at all for the past eleven months, even though the state as a whole would have been worse off.[41]

Accordingly, TURN proposes the following revenue allocation adjustments to avoid penalizing PG&E customers by eliminating that loss that would result from applying average costs to Helms-related consumption and production:

a) Reduce PG&E's net short loads in the January-June 2001 period based on recorded monthly operations of Helms. This requires subtracting both Helms-related generation output and pumping electricity consumption; in other words, treating Helms as if it did not exist. This will save PG&E ratepayers from bearing higher costs for Helms' operation during a period when the plant's operation was necessary to prevent blackouts.

b) A similar adjustment is proposed for the consumption and output of Helms from July 2001 and forward. However, because DWR's data are inadequately disaggregated to calculate the forecast operation of Helms, TURN proposes that Helms pumping be subtracted from PG&E loads and Helms generation be subtracted from PG&E generation when truing up any balancing account entries to actual net short kWh and allocated costs starting in July 2001.

One of these adjustments is a credit to PG&E to reflect the benefits of the Helms pumped storage facility. PG&E also computed a similar adjustment for Helms, though the calculation is different (compare Ex. 166 and 171). Both PG&E and TURN seek to make PG&E indifferent in regard to the

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[41] Ex. 169, pp. 7-8.

operation of Helms. Exhibit 166, which illustrates PG&E's adjustment using non-confidential hypothetical numbers, describes a series of computations whereby a credit reflecting the pumping losses is made to PG&E, resulting in Helms revenues and costs being equal (See PG&E/Alvarez, RT 6326).

TURN's objective is to completely remove the effects of Helms from the PROSYM outputs, as shown in Exhibit 171. PROSYM is an hourly chronological production cost model, and fully capable of dispatching Helms in the most efficient way. Access to PROSYM would have allowed parties to determine precisely the net benefit of Helms and assure that it is allocated to PG&E rather than relying on methods which merely make PG&E indifferent.

We shall adopt the adjustments for Helms, proposed by TURN in order to promote more economically efficient price signals in the operation of the Helms facility. The TURN approach seems more straight forward to implement than that of PG&E, and allows for prospective true-ups.

(3) Adjustment to Reflect Differences in Self-Provided Ancillary Services

TURN proposes that the allocation be adjusted to recognize differences among the utilities in the amount of ancillary services that each utility provides for itself. There has been a major downward decline in the ancillary services market in recent months, such that the vast majority of ancillary service costs incurred by DWR occurred during the first two quarters of 2001. Self-provision of ancillary service costs was less of a factor during that period.

TURN provided a table showing its proposed adjustment factors relating to self-provision to be applied to gross load. TURN used these adjustment factors to allocate ancillary service costs in Ex. 170. TURN proposes the following adjustment percentages to apply to gross load, relying on data received from the utilities regarding the total system ancillary services self-provided by each utility[42] :

	January-June	July-December
PG&E	51%	20%
Edison	75%	64%
SDG&E	100%	100%

As recommended, we shall apply TURN's recommended adjustments by total gross load for the first two quarters of 2001, and by adjusted gross load for the period from the third quarter of 2001 to the end of 2002 to reflect the greater self provision starting in July 2001.

Consistent with these adjustments, we adopt the allocation methodology and percentages as computed by TURN. The resulting allocation of revenue requirement and associated percentages are as follows:

Utility	$000's Revenue Allocation	% Allocation
PG&E	$ 4,765,407	47.6%
SCE	$ 3,674,066	37.7%
SDG&E	$ 1,563989	15.6%
Total	$ 10,003,461	100%

IX. Implementing Annual DWR Update Proceedings

A. Annual Revisions of DWR Revenue Requirement

As prescribed in AB1X (Water Code Section 80134(a)), DWR will revise its retail revenue requirement at least annually. Consistent with the statute, we

[42] These figures are the 100% minus percentage of total ISO ancillary services (excluding self-provided marketers and municipals) self-provided by each utility, with PG&E set at 20% to reflect that it does not self-provide 100% of all services. (Ex. 170)

adopt a procedural plan for DWR to submit to the Commission updated forecasts of its retail revenue requirement on at least an annual basis.

The revenues provided to DWR from the charges that we implement in today's order (together with revenues that DWR has already collected from the utilities to date) will provide recovery of DWR's revenue requirements from January 17, 2001 through December 31, 2002.

We hereby schedule the next update of the DWR revenue requirement to be submitted to the Commission on June 1, 2002, with revised DWR charges to take effect on January 1, 2003. At that time, DWR will submit a revised annual revenue requirement forecast covering the period January 1, 2003 through December 31, 2003. The updated DWR charges that we subsequently implement to take effect on January 1, 2003 will therefore provide recovery of DWR's revenue requirement for that subsequent 12-month period of January 1, 2003 through December 31, 2003. We shall direct the ALJ to issue a further ruling, as necessary, setting forth the manner and process whereby the DWR update shall proceed.

B. DWR’s Tracking of Forecast Versus Actual Cost and Revenue Variances

We acknowledge parties’ concerns that DWR’s revenue requirement is based on forecasts that may prove to be incorrect over time. Various parties have asked the Commission to require DWR to set up balancing accounts to true-up the difference between its total estimated and actual expenditures on a retroactive basis. Actual DWR monthly costs will depend on each utility's net short position, which in turn will depend on demand and plant availability. Balancing accounts will mitigate associated cost forecasting errors.

Because DWR is responsible for communicating to the Commission its revenue requirement and any subsequent adjustments, we expect DWR to take responsibility for identifying necessary periodic adjustments in its revenue requirement over time to reflect variances between actual and forecasted costs and to take into account actual and projected fund balances when determining its revenue requirements.

Our goal is that, over time, the customers will pay no more than the cost of DWR service. In order to achieve this goal, we will set up a process whereby the actual costs incurred will be compared with the forecast costs that were recovered through customer charges. Then, we will set prospective DWR charges for each service territory so that, over time, the DWR charges paid will approximate the actual costs incurred in providing DWR service to customers. We will also make provision for the utilities to amortize over or undercollections of past DWR revenue requirements, as explained below. We intend to conduct this process as part of an annual update processing of DWR's revenue requirement.

As discussed in the technical workshop and in DWR's August 1 response, DWR contemplates updates to the revenue requirement at least annually as required by AB1X. If there are significant prolonged variances between forecsted and actual revenue requirement, DWR states that it is likely that more frequent adjustments or exceptions to the annual adjustment would be made.

DWR states that, over time, the actual revenues that it collects will indeed track the actual net short energy requirements of the customers of each utility service area as well as the amount of self-provision of ancillary services. As discussed at the workshop, DWR will track its net short energy purchases and ancillary service purchases to compare against the projected accruals of the revenue requirement and will update projections on a monthly basis. DWR will use this monthly monitoring to determine if there should be any adjustment, up or down, in the revenue requirement and the associated recovery of that revenue requirement from the customers of the respective utilities. To the extent that any material differences arise, either positively or negatively, DWR will submit an adjusted revenue requirement to the Commission. We encourage DWR to work with the Commission and its staff to closely monitor this tracking process

C. Utility Balancing Accounts and True Ups[43]

We shall also direct the utilities to establish their own separate balancing accounts to assure that differences between forecasted and actual DWR revenue requirements allocated to each utility service territory are properly adjusted in retail rates collected from customers over time. The utilities' balancing accounts shall be trued up, pursuant to a subsequent Commission order, no later than during each annual update proceeding for DWR.

Parties disagree about the process for maintaining utility balancing accounts and true-ups. There is general agreement that DWR should provide an accounting of its actual costs and should true-up its forecasts to actual. Parties disagree, however, as to how any true ups of DWR's forecast-to-actual costs should be applied among the utilities. Specifically, parties disagree as to whether the adopted allocation percentages should be subject to true up to reflect actual recorded data. PG&E proposes that while the Commission should require balancing accounts to track differences between DWR's forecasted versus actual costs in the aggregate, it should not readjust the adopted percentage allocation of DWR costs on an after-the-fact basis. PG&E's proposes that DWR's actual costs, as tracked by DWR, be allocated among the three utilities in the same

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43 As used in this order, the term "true up" has reference to the process of making prospective adjustments to reflect the difference between forecasted and actual results that occurred in a prior period.

proportions that the Commission adopts in this proceeding to allocate DWR's revenue requirement. PG&E proposes that any difference between the amounts remitted by a utility on behalf of its customers and its customers' share of actual DWR costs would then be incorporated into the overall rates for that utility's service territory during an appropriate DWR update proceeding.[44]

PG&E suggests that the Commission might decide to review the adopted DWR allocation factors on a regular basis, perhaps annually. Should a utility believe that the adopted percentage for it is no longer appropriate and that adjustment should be made before the next scheduled proceeding, it would have the ability to file an application to request that the adopted percentage be modified. Aglet agrees with PG&E that balancing accounts should be used to adjust total DWR costs to actual, but not to revise the allocation percentages per utility. Aglet witness Weil proposes that the balancing account be interest-bearing and incorporated into the tariffs of each utility.

SCE's disagrees with PG&E's approach, proposing that both the total DWR costs *and* the percentage allocation be revised for each utility on an after-the-fact basis. SCE believes that truing up the actual percentages will assure that no customers pay more or less than actual cost incurred to serve those customers. PG&E objects to truing up the allocation percentages, arguing that it increases uncertainty, and raises the possibility of utilities' "gaming" their net open positions. More specifically, PG&E argues that an after-the-fact true up of the utilities' relative net short positions could create perverse incentives for utilities to change their net short positions.

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[44] Ex 163, pp. 1-9 -- 1-10.

As an example, assume that the average DWR cost being allocated to a utility service territory for its net short position is $100/mWh, and that each utility is allowed to true up their DWR allocation percentage to reflect the difference between forecasted and actual net short. In such a case, a utility could have an incentive to reduce its net short merely to maximize its customers' savings through the true up process. The utility may choose to increase its own share of net short in such an instance even when it was more economically efficient from an overall statewide perspective for DWR to procure the net short. For example, if DWR's actual incremental cost for the net short turned out to be only $50/MWh while the utility's incremental cost was $95/mWh, the utility would have a peverse incentive to capture the incremental savings for customers in its service territory of $5/mWh (i.e., $100-$95/mWh) through the true up. Thus, paying the $95/mWh for additional power would work to the advantage of the customers in that utility's service territory even though it would be economically more efficient from a statewide perspective for DWR to procure the power at $50/mWh. Such a perverse incentive to minimize the net short is avoided if utilities are held to their adopted allocation percentages, and true ups of allocation percentages to reflect utilities' actual net short positions are not permitted.

We shall authorize each of the utilities to establish balancing accounts to track revenues remitted to DWR from customers in each service territory and costs allocated from DWR based on charges established in this order. We agree that the allocation percentages adopted in this order should not be subject to true up to avoid incentives for inefficiencies as discussed above. The difference between estimated and actual total DWR expenditures will be applied among utility customers using the originally adopted allocation percentages.

For purposes of balancing account tracking, each utility shall segregate kWh sales of URG power versus sales of DWR power. The utility shall credit each month the revenues that are attributable to that portion of total sales that are provided by DWR on an actual basis. The revenues shall be equal to actual billed kWh sales attributable to DWR multiplied by the charge per kWh adopted in this order. Such revenues are the property of DWR, and shall be remitted to DWR as prescribed in this order.

At the designated time for DWR to submit its revised forecast for the coming year, DWR will also submit its true up of the prior periods' differences between forecasted and actual data. The difference between actual costs incurred and actual revenues collected by DWR will resulting in either an undercollection or overcollection. The total under-or-overcollection in revenue requirement will be assigned pro rata to the customers of each utility based on the allocation percentages adopted in this order. Any overcollection or undercollection will be taken into account, as appropriate, in determining subsequent retail rate adjustments.

Aglet recommends that balancing accounts established by the utilities should be interest bearing and should be reflected in the filed tariffs of the utilities. No party objects to this provision, and we find it reasonable. Applying interest to the balancing account will properly recognize the time value of money. Accordingly, we shall direct the utilities to add appropriate provisions to their filed tariffs, establishing balancing accounts to recognize over and undercollections of DWR-related costs consistent with this order. The authorized balancing accounts shall bear interest on the same basis as is applicable to other utility balancing accounts.

X. Implementation of DWR Revenue Remittance Procedures

A. Establishment of a Separate Charge for DWR Electric Power

The Commission's responsibility is to set the overall rate that electric customers see on their bills. However, parties generally agree that breaking this charge down to reflect a separate amount per kWh sold by DWR will make the rate structure more efficient. SCE and PG&E maintain that breaking out a DWR charge will eliminate the need for them to maintain their own balancing accounts for DWR payments and revenues. Instead, the actual amount of revenue that is generated by reference to the DWR charge and the amount of kWh sold by DWR would be remitted directly to DWR.

By letter to the Commission dated May 2, 2001, DWR has also stated that the charges set for recovery of its revenue requirements "should be independent of rates payable by retail end use customers for power purchased by such customers from the utilities, and by law, must be sufficient in order for the Department to recover the revenue requirements attached hereto." DWR stated that revenues resulting from such rates should be measured as a function of the amount of power sold by DWR, and not as a function of the amount of power sold by each respective utility. DWR specified the revenue requirement on a separately allocated and combined basis for the service territories for each of the three utilities.

We agree that it is reasonable to implement DWR cost recovery as an amount per-kWh that is attributable to sales by DWR.[45] Although the effect may

[45] While we establish a separate per-kWh charge for DWR, we do not require the utilities to show this charge as a separate line item on customers' bills. We have discussed this in our orders adopting Servicing Agreements between DWR and SCE, SDG&E, and PG&E, respectively.

be muted by the use of external financing proceeds to pay for procurement costs, establishing a per kWh charge for DWR will cause its revenues to vary in some proportion to the amount of energy it is procuring. This approach facilitates the independent calculation of charges that will be segregated and remitted directly to DWR. The forecasted net short position in GWh and the revenue requirement to be allocated to each utility provide the basis for the calculation of a system-wide amount per-kWh sold for electricity sold by DWR to the customers of each utility.

Accordingly, we shall direct each of the utilities to begin disbursing payment to DWR for its revenue requirement based on the relevant DWR charge, as adopted above, for each kWh sold by DWR to the utility's customers. Utilities shall begin calculating and distributing payments on this basis as applied to kWhs billed on and after March 1, 2002.

B. Procedures for the Remittance of Funds to DWR

We have previously adopted servicing agreements between DWR and each of SDG&E and SCE, and a servicing order relating to PG&E. These decisions provide for the utility services required by DWR to perform functions authorized by the Water Code.[46] The servicing agreements for SDG&E and SCE set forth the terms under which each utility will provide transmission and distribution of DWR power to electric customers, and provide billing, collection, and related services for AB1X-authorized power purchased by DWR.

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[46] *See* A.01-06-044, filed June 25, 2001 for Edison's Servicing Agreement, and A.01-06-039, filed June 22, 2001, for SDG&E's Servicing agreement. PG&E's Servicing Agreement was considered in this docket (A.00-11-038 et al.) as a result of DWR's letter of June 27, 2001 requesting that the Commission order PG&E to provide certain services to DWR.

The servicing agreement for PG&E also addresses details concerning the manner and timing of remittance of funds to DWR. In D. 01-09-015, as stated in Finding of Fact 25, however, the servicing agreement (in Section 2 of Attachment E) allows PG&E to seek Bankruptcy Court approval of the servicing agreement. The Bankruptcy Court has not yet approved PG&E's servicing agreement.

On December 6, 2001, an ALJ ruling provided notice that the Commission was considering implementing DWR remittance procedures for PG&E utilizing language from excerpts of the servicing agreement that PG&E negotiated with DWR, which was approved by the Commission in Decision No. 01-09-015. The pertinent excerpts were appended as an attachment to the ruling, specifying procedures for PG&E's remittance methodology.

PG&E filed a response expressing objections to the use of the language from the servicing agreement as a basis for remittance of proceeds that PG&E owes to DWR. PG&E claims that interim remittance arrangements that have been used up until now are adequate, and that it is inappropriate to extract sections of the servicing agreement out of context from the whole agreement.

In its comments, DWR seeks to remove a parenthetical clause, "(exclusive of Imbalance Energy)," from Section 4 of the Attachment B remittance methodology.[47] DWR argues that FERC recently confirmed that DWR, as the creditworthy party, is responsible for such charges.[48] For this reason, DWR argues PG&E should be remitting revenues to DWR for Imbalance Energy.

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[47] DWR Comments, p. 2.

[48] FERC, Order Granting Motion Concerning Creditworthiness Requirement And Rejecting Amendment No. 40, ER01-3013-000 and ER01-889-008, issued November 7, 2001.

DWR also argues that any remittance order should require PG&E to provide an accounting for, and to remit to DWR, all DWR revenues received in respect of imbalance energy prior to the effective date of the order. Finally, DWR believes the remittance order should contain an express requirement for PG&E to deliver all power made available by DWR. If DWR is responsible for procuring all imbalance energy and other ancillary services, DWR expects assurances that such energy and other services is delivered to retail end use customers.

SCE also filed comments in response to the ruling. SCE does not address the appropriateness of the Commission adopting this remittance methodology for PG&E, as this issue is currently before the U.S. Bankruptcy Court. However, SCE questions whether DWR is asking the Commission in its comments to make the same change to SCE's servicing agreement with DWR. For example, DWR requests that the Commission incorporate "Section 2.2(d), Section 4.1, Section 4.2, and Section 6 of Attachment E" of the PG&E servicing agreement into any remittance order for PG&E. With respect to Sections 4.1 and 4.2, DWR states these "are the general provisions concerning remittances <u>which should be applicable to all three investor-owned utilities</u>."[49] Section 4.2 of the PG&E servicing agreement, which DWR would make applicable to all three investor owned utilities, states that the "Utility shall determine the Daily Remittance Amount in the manner set forth in Attachment B hereto." DWR proposes to change Attachment B to include remittance for Imbalance Energy. SCE argues that the Commission should not entertain any "back-door" attempt by DWR to unilaterally change the mutually agreed-upon and Commission-approved servicing agreement between SCE and DWR.

[49] DWR Comments, pp. 2-3. (Emphasis added.)

Issues associated with DWR's responsibility for Imbalance Energy charges, among other things, and the remittance of revenues to cover those costs, were not resolved in the negotiations that formed the basis for the servicing agreement for SCE. It was agreed that those issues would be considered at a later point in time. For the past six months, SCE has been negotiating with DWR regarding DWR's responsibility for ISO charges incurred to serve SCE's customers, along with other issues. SCE currently has a proposal before DWR to resolve these issues.[50] The Commission should not, based on the incomplete record before it, short-circuit that process and unilaterally change SCE's servicing agreement with DWR.

In its December 6 letter, DWR reports that it is paying the ISO, under protest, certain disputed amounts and that those disputed amounts were not included in its revenue requirement request. The dispute is as to whether DWR or the utilities are responsible to pay these amounts to the ISO. We have not considered or decided in this proceeding who should pay the ISO. However, we will not allow circumstances to develop such that ratepayers pay both DWR and utilities for same ISO costs

For PG&E, we shall direct that PG&E follow the remittance procedures based on the relevant language extracted from its servicing agreement, as set forth in the December 6, 2001 ALJ ruling. We shall also require PG&E to account

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[50] Among the issues to be addressed is determining the amount of Imbalance Energy DWR actually provided to SCE's customers. For example, the following issues must be addressed to determine the amount of Imbalance Energy DWR provided: (a) establishing distribution losses; (b) determining treatment of energy dispatched by the ISO from IOU generation to serve other ISO-area load; and (c) accounting for ISO sales of pre-scheduled DWR energy for which SCE has previously paid DWR. SCE is attempting to resolve these issues with DWR.

for and to remit to DWR, all DWR revenues received with respect to Imbalance Energy prior to the effective date of the November 7, 2001 FERC order. Although PG&E's servicing agreement, itself, has not been approved by the Bankruptcy Court, we conclude that the relevant language extracted from the servicing agreement, as identified in the December 6, 2001 ALJ ruling, provides an appropriate basis for the collection and remittance of funds to DWR. We also conclude the requirement to include Imbalance Energy is reasonable in that DWR is responsible for procuring all Imbalance Energy and other ancillary services for customers in PG&E's territory.

For SCE and SDG&E, we shall simply direct that they make payments in accordance with their approved servicing agreements. Unlike PG&E, those servicing agreements are already in effect and prescribe how funds are to be remitted. We hesitate to interfere with the ongoing negotiations that are in progress between SCE and DWR regarding responsibility for ISO charges without further record development as to all of the ramifications involved.

C. Payment for Shortfalls in Prior Period DWR Remittances

For each utility, a separate one-time payment from each utility shall be required to reimburse DWR for its shortfall in costs that have already been incurred from the period when DWR began procuring power on behalf of the customers of that utility's service territory up through the date when the prospective monthly payment of charges prescribed in this order takes effect. These payments shall be made out of amounts previously collected by the utility from customers pending allocation between DWR and the utility. In prior orders, we have established interim amounts that each utility was to pay to DWR pending the final determinations made in the instant order.

The separate lump sum payment for DWR procurement costs prior to March 1, 2002 shall be calculated as follows. The per kWhr charges for each utility's customers adopted in this order multiplied by the applicable DWR sales to those customers for the applicable period beginning on or after January 17, 2001 through March 1, 2002 shall determine the amount to be remitted for that utility. From this amount, the utility shall subtract the amounts that have already been remitted to DWR on an interim basis. Each utility shall then remit additional funds to DWR as a lump sum payment, for any shortfall in the amounts already remitted for DWR power delivered.

PG&E and SCE should already be collecting and remitting to DWR an amount determined by multiplying the sum of their utility-specific generation rate and the energy surcharge rates as authorized by the Commission in D.01-05-064 by the volume of power delivered to their customers on behalf of DWR since June 1, 2001.[51] The utility-specific DWR charges we have calculated in this order indicate that PG&E and SCE need to remit to DWR an amount above the funds they have already remitted since the energy surcharges took effect on June 1, 2001. For SDG&E we established an initial generation rate component of 6.5 cents/kWh in D.01-05-060. In D.01-09-059, we adopted an interim rate increase for SDG&E that provided for remittance of DWR charges at the rate of 9.02 cents/kWh for sales on and after September 30, 2001. SDG&E's lump sum remittance to DWR for power sales prior to March 1, 2002 shall be net of any funds that have already been remitted for DWR sales on that interim basis.

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[51] In D.01-03-082, the Commission granted an energy surcharge three cents per kWh for PG&E and SCE, prescribing that a portion of the surcharge would be allocated to DWR.

DWR will receive from each utility the revenues that the utility collects on behalf of DWR, based on the fixed DWR charge per kWh as noted above. The per-kWh charge payable to DWR shall remain fixed, even though the actual percentages of system sales supplied by DWR will vary each month. However, the retail rate applied on each utility customer's bill will not fluctuate from month-to-month merely due to changes in the percentage of sales supplied by DWR each month. Such monthly fluctuations on customer bills would cause undue customer confusion.

Instead, the respective share of sales attributable to DWR versus utility URG sales shall be tracked through the balancing accounts that we have directed to be established elsewhere in this order.

With fixed retail tariffed rates and a fixed per kWh charge payable to DWR, there is, in effect, an amount that the utility is entitled to receive for its own account for the kWhs that it supplies to its retail customers. We will call this amount the "imputed utility rate." To the extent that the actual percentage of DWR sales to each utility's retail customers is either less than or exceeds the forecast percentage of DWR sales to those customers for any month, the customers' bills for that month will not reflect exactly the imputed utility rate for the kWhs the utility provides. The balancing account mechanisms that we have authorized elsewhere in this order are intended to ensure that over time, the utility recovers its imputed utility rate by segregating the effects of DWR sales and providing for a true up of estimated to actual DWR sales and allocated costs.

As noted above, although the end user's retail rates will not fluctuate to reflect monthly differences in DWR sales, the rate per kWh that is included in the bill for the power that the utility itself provides through URG sources (i.e., the "effective utility rate") will vary from month to month. By truing up the utility balancing account at a later date, we will ensure that the utility bills, and its customers pay, (over time) the imputed rate for utility-supplied power.

XI. DWR Revenue Requirement Implications for Utility Rate Needs

In today's decision, we make no changes in the existing overall rate levels being charged to end-use customers of the three utilities. Any overall rate changes for SDG&E customers will be addressed in a separate order in A.00-10-045 et al. Any rate changes for PG&E customers will be addressed in these consolidated dockets. SCE customers' rate levels are currently frozen in accordance with the settlement that it has recently entered into. In this decision, we simply order the three electric utilities to remit to DWR its revenue requirement as provided to us, as modified herein, and as collected from end-use retail customers in those utilities' service territories through application of the charges we approve today. As previously discussed, any rate adjustments for the respective utilities will be addressed in conjunction with the URG phase in the applicable dockets.

We recognize that the utilities still incur ongoing expenses for their own URG, that is, the generation that remains under the control of the utilities. Proceedings are currently underway in a separate phase of these dockets to adopt revenue requirements for the URG-related costs for PG&E and SCE, respectively. Pending our subsequent adoption of URG revenue requirements, we cannot be certain whether revenues now being collected by the utilities through existing rates will be sufficient both to fund the DWR requirement and the URG requirements. We will not prejudge the subsequent outcome of the URG phase of these proceedings. Based upon the estimates of URG revenue requirements that have been submitted as testimony in that phase by PG&E and SCE, however, we note that there is a range of potential outcomes that could be decided by the Commission. Depending on the amount within that range the Commission ultimately adopts, there could be either a shortfall or surplus of revenues for PG&E or SCE, respectively. We will address these possibilities, as necessary, in future proceedings. We acknowledge the need to promptly consider and act upon any financial consequences, as warranted, that may result from our order today.

XII. Comments on the Proposed Decision

The Proposed Decision of ALJ Pulsifer was mailed to parties on January 8, 2002. Pursuant to Section 311(d), the Commission will not take action on this matter for 30 days. Consistent with Rule 77.2, comments are due on the proposed decision within 20 days of its date of mailing. No extensions of this comment period will be granted, nor will any late-filed comments be accepted. Pursuant to Rule 87, we will reduce the reply comment period provided for in Rule 77.5 to four days. Because the fifth day following opening comments falls on a weekend, good cause exists for shortening the reply period to four days to provide sufficient time for review of reply comments. Therefore, comments must be filed and served by January 28 and reply comments must be filed and served by February 1. Comments and reply comments should be served on the ALJ electronically at trp@cpuc.ca.gov.

Findings of Fact

1. AB1X, among other things, authorized DWR to purchase power on behalf of retail customers in the service territories of PG&E, SCE, and SDG&E.

2. AB1X authorized DWR to determine its revenue requirement sufficient to recover its procurement-related costs, and required the Commission to implement the cost recovery of DWR's revenue requirement.

3. Timely implementation of DWR's revenue requirement cost recovery is necessary to support the sale of bonds as prescribed under California Water Code Section 80130.

4. Up until the present time, DWR has been relying on interim borrowings as its funding source pending the sale of bonds, currently expected to occur in the second quarter of 2002.

5. DWR's revenue requirement represents the amounts to be collected from customers in the service territories of the three major electric utilities covering the 2001-2002 time period, after deducting the proceeds from interim loans.

6. DWR submitted an initial estimated revenue requirement on May 2, 2001, covering the 18 months from January 2001 to May 31, 2002.

7. DWR provided the Commission with an updated revenue requirement on July 23, 2001, covering 24 months ending December 2002, and provided further updates on August 7, October 19, and November 5, 2001,.

8. Parties of record were provided notice and an opportunity to review DWR's revenue requirement submittals, to participate in technical workshops, and to file comments in response to DWR's submittals.

9. Parties expressed disagreement with various assumptions underlying DWR's revenue requirement, and contested DWR's representation that DWR's costs are "just and reasonable."

10. DWR presents its revenue requirement on an aggregate basis for all three utilities, but defers to the Commission to determine and apply an allocation rationale for assigning the revenue requirement among customers in each service territory

11. In D.01-03-082, the Commission granted a surcharge increase of three-cents per kWh to be collected by SCE and PG&E, prescribing that a portion

of that surcharge would be allocated to DWR upon receipt, analysis, and comment on DWR's revenue requirement.

12. In D.01-05-060, the Commission established an initial generation rate component of 6.5 cents/kWh for SDG&E.

13. In D.01-09-059, the Commission provided an interim rate increase to SDG&E to provide for remittance to DWR at 9.02 cents/kWh.

14. DWR forecasts a total revenue requirement to be collected of $10.003 billion, as set forth in Appendix A of this decision, covering the period January 17, 2001 through December 31, 2002.

15. DWR states that it has determined that its revenue requirement is just and reasonable based upon several factors including its competitive solicitation of bids, cost-based recovery, and the true-up provisions of forecast variances that will take place in future adjustments.

16. DWR's revenue requirement includes $5.284 billion in long-term power costs and $9.534 billion for short term purchases procured on behalf of customers in the service territories of the three major electric utilities.

17. DWR's revenue requirement includes $1.102 billion for ancillary service costs incurred by DWR on behalf of customers in the service territories of the three major electric utilities.

18. Pursuant to a FERC Order issued on November 7, 2001, the ISO sent $956 million in invoices to DWR for transactions with third party power suppliers for the period January 17 through July 31, 2001, on behalf of the noncreditworthy entities, PG&E and SCE.

19. The sales that DWR has presented in its revenue requirement model for purposes of computing charges for remittance purposes do not include sales to direct access customers.

20. It is reasonable to implement DWR cost recovery in the form of a discrete amount per kWh sold by DWR to facilitate segregation of DWR funds from those of the utility.

21. DWR's revenue requirement does not include a provision to account for franchise fees associated with power that it sells to utility customers.

22. Unresolved questions remain concerning the rights of municipalities to receive franchise fees on DWR power sales, and the respective obligations of DWR or investor-owned utilities to collect and remit franchise fees on DWR power sales.

23. DWR's revenue requirement is comprised of cost categories as authorized for recovery from utility ratepayers under AB1X, including the costs of long term and short term power contracts, ancillary services, administrative overhead, demand-side management, uncollectibles, and an allowance for leads or lags in cash receipts and disbursements.

24. DWR's revenue requirement is based on forecasts of various costs that may prove to be incorrect over time.

25. The allocation of DWR's revenue requirement as adopted in the ordering paragraphs below results in a revenue responsibility (in dollars and percentages) for PG&E's service territory in the amount of $ 4,765,407,000 (47.6%); for SCE's service territory of $3,674,066,000 (37.7%); and for SDG&E's service territory of $1,563,989,000 (15.6%).

26. The allocation of DWR's revenue requirement as adopted in the ordering paragraphs below results in a uniform cents per kWh charge applicable to billed revenues for PG&E's service territory in the amount of 10.047; for SCE's service territory in the amount of 10.309; and for SDG&E's service territory in the amount of 9.947.

27. The Commission has traditionally recognized the general principle that utility revenues should be allocated among customer classes on the basis of cost causality.

28. Allocation of the DWR revenue requirement is a novel application of the Commission's cost-based ratemaking since it involves allocation across different utility service territories, as opposed to the traditional practice of allocation among customer classes within a single utility service territory.

29. A pro rata allocation of procurement costs on a statewide basis is not inconsistent with cost-based ratemaking principles to the extent that no other objective measure exists to differentiate cost incurrence on more disaggregated basis.

30. The utility-specific adjustments proposed by TURN more accurately reflect cost causality, namely, (a) adjustment of retail net short to exclude WAPA load for PG&E; (b) removal of the effects of PG&E's Helms facility; and (c) adjustment for each utility's self-provided ancillary services.

31. The allocation of revenue requirements based upon cost of service provides for an equitable and economically efficient matching of cost responsibility with service rendered.

32. The allocation approaches proposed by SDG&E and SCE seek to apply a cost-based approach by relating the costs of specific supply sources with specific utility service territories in geographical proximity.

33. The SCE and SDG&E allocations segregate energy sources on a geographic basis, with sources transmitted over facilities (a) north of Path 15 being allocated to PG&E customers, and (b) south of Path 15 being allocated to SCE and SDG&E customers.

34. SDG&E's allocation approach separately allocates both long term and short term energy purchases on a geographically differentiated basis.

35. SCE's allocation approach allocates only short term energy purchases on a regionally differentiated basis, but treats long term purchases as a homogeneous cost to be allocated on a pro rata statewide basis in relation to the net short position of each utility.

36. DWR purchased only short term power during the first few months of 2001, then began procuring long term power in April of 2001.

37. DWR's short term purchases had different terms than long term contracts, but served a similar purpose in supplying the joint needs of customers in the service territories of the three major utilities.

38. DWR's contracts have served to stabilize the power market, to the benefit of all California ratepayers.

39. Most of the DWR's costs and cash reserves related to its power purchase program are not specific to any single utility.

40. DWR generation is not necessarily dedicated to any particular off system sales customers, and disproportionate assignment of DWR revenues of a geographical basis would be arbitrary.

41. SCE fails to provide an objective criterion to justify applying different allocation approaches between long term fixed price contracts and supply sources of 90 days or less.

42. DWR did not procure separate portfolios of supplies for each of the three utility service territories such that specific supply sources could be exclusively identified with service to any one particular utility service territory.

43. DWR's stated procurement policy was to use power purchased under many contracts to meet the net short position in more than one utility service territory, directly or though swaps, exchanges, or otherwise.

44. The allocation of DWR costs on the basis of geographical differentiation between NP15 and SP 15 presumes a cause-and-effect relationship between the

location where energy supplies were procured and the specific utility service territory in which the associated electricity was consumed.

45. For certain power supplies procured north of Path 15, DWR incurred usage charges relating to transmitting power from north to south over Path 15 during periods of expected congestion, a situation that has been referred to as a "transmission constraint."

46. Congestion-related usage charges could be imposed simply on the expectation that Path 15 congestion would occur in the day-ahead power market even when there turned out to be no actual transmission congestion in real time.

47. The congestion-related charges incurred by DWR for power transmitted over Path 15 were an artifact of a statewide dysfunctional power market which have subsided after FERC adopted measures to help minimize or eliminate market flaws in the California electric power market.

48. To the extent that Path 15 congestion-related charges were an artifact of a statewide dysfunctional market, those charges cannot be causally related just to one service territory to the exclusion of another, but are a statewide phenomenon.

49. The causes of price differentials between NP 15 and SP 15 were not necessarily related exclusively to congestion, but to some extent were a function of other factors such as *when* the related contract was signed.

50. The timing of when particular contracts were signed was not linked to specific utility service territories. Instead, DWR was trying to find power wherever it was available, particularly during the early months of 2001, to address the statewide power crisis.

51. Aside from deficiencies in the theoretical soundness of geographically differentiated cost allocations over Path 15, the unreliability of the empirical

modeling data underlying the cost differential provides an additional reason not to allocate disproportionately higher costs to PG&E customers.

52. Use of hourly data for allocation purposes has theoretical appeal as a means to promote linkage between DWR costs and revenues, but unanswered questions concerning the availability, complexity, and litigiousness associated with such data make it inadvisable to adopt such a requirement at this time.

53. Pursuant to Executive Orders issued by the Governor, DWR has been given responsibility and has been authorized to implement the 20/20 Rebate Program.

54. The DWR cents per kWh charges are computed by dividing the allocated DWR revenue requirement assigned to each utility's service territory by the applicable kWh sales to the utility’s customers provided by DWR.

55. DWR agrees to track its net short energy purchases and ancillary service purchases to compare against the projected accruals of the revenue requirement and will update projections on a monthly basis.

56. DWR’s monthly monitoring will be used to determine if there should be any adjustment, up or down, in the revenue requirement and the associated recovery of that revenue requirement from the customers of the respective utility service territories.

57. Although the end user's retail rates will not fluctuate to reflect monthly differences in DWR sales, the rate per kWh that is included in the bill for the power that the utility itself provides through URG sources (i.e., the "effective utility rate") will vary from month to month.

58. With fixed overall retail tariffed rates and a fixed per kWh charge payable to DWR, there is, in effect, an amount that the utility is entitled to receive for its own account for the kWhs that it supplies to its retail customers, referred to as the “imputed utility rate.”

59. Truing up the utility balancing account at a later date to account for under or overcollections of DWR revenues will ensure that the utility bills, and its customers pay (over time), the imputed rate for utility-supplied power.

60. The applicable kWh sales for computing prospective remittances under the DWR charges established in this order cover the period from March 1, 2002 through December 31, 2002.

61. It will be necessary for each utility to remit to DWR lump sum payments for DWR energy delivered to customers prior to March 1, 2002, to the extent that prior interim remittances to DWR were less than the amounts indicated for those prior periods under the allocation of DWR's $10.003 billion revenue requirement as adopted herein.

62. The servicing agreements that have been approved for each of the utilities includes provisions prescribing the billing, collection, and related services to be performed by each utility relating to AB1X-authorized power purchases by DWR.

63. Although D. 01-09-015 allows PG&E to seek Bankruptcy Court approval of its servicing agreement, the Bankruptcy Court has not yet approved PG&E's servicing agreement.

64. Even though the Bankruptcy Court has not approved PG&E's servicing agreement, the relevant language in PG&E's servicing agreement pertaining specifically to the billing, collection, and remittance of funds to DWR can still be independently extracted and incorporated for use in this order.

65. The FERC has recently confirmed that DWR, as the creditworthy party, is responsible for Imbalance Energy charges for PG&E.

Conclusions of Law

1. Under the provisions of Water Code Section 80110, it is within the authority of the DWR to conduct and determine any just and reasonable review of its revenue requirement pursuant to Public Utilities Code Section 451. Accordingly, this Commission makes no independent conclusions concerning whether the DWR revenue requirement implemented in this order is just and reasonable.

2. DWR is legally entitled to payment for its revenue requirement associated with power it purchases and sells to retail end-use customers pursuant to Division 27 of the California Water Code.

3. Pursuant to the mandates of AB1X, a revenue requirement for DWR should be implemented in accordance with the provisions of this order.

4. Based on the amounts that DWR has submitted pursuant to its authority under Water Code Section 80110, the total revenue requirement to be implemented totals $10.003 billion for the service areas of the three major California utilities, covering the period January 2001 through December 2002.

5. DWR should be entitled to recover revenues in an amount equal to the number of kWh sold by DWR and billed to customers in the service territories of PG&E, SCE, and SDG&E, respectively, multiplied by the relevant charges as set forth in the Ordering Paragraph (O.P.) 3 below.

6. Based upon the estimates of URG revenue requirements that have been submitted as testimony in that phase, there is a range of potential outcomes that could be decided by the Commission that could result in either a shortfall or surplus of revenues for each of the utilities.

7. The effect of this order on the need for retail rate increases for the utilities cannot be determined until after the URG phase of this docket is completed.

8. The effect of this order on the need for interim retail rate increases for SDG&E is subject to consideration in a separate docket (A.00-10-045 et al.).

9. It is reasonable to adopt a statewide pro rata allocation of revenue requirement (with utility-specific adjustments as proposed by TURN) based upon the respective net short position among the service areas of the three utilities.

10. The adoption of a pro rata statewide allocation of DWR revenue requirement represents a reasonable application of a cost-based revenue allocation of the DWR revenue requirement and related DWR charges to be applied among the service areas of the three utilities.

11. The goal of our cost allocation is that electricity customers in each utility's service territory pay for the cost of providing DWR service in that territory.

12. A process should be established whereby the actual costs incurred in each service territory will be compared with the costs that were previously projected in order to set future DWR charges.

13. DWR's periodic adjustment to its revenue requirement should reflect the variances between actual and forecasted costs, and take into account actual and projected fund balances.

14. DWR should provide an adjustment to its revenue requirement at the time of its next update of revenue requirements, reflecting the removal of the interim loan costs if, in fact, DWR still expects the long term bonds to be issued on schedule at the end of June 2002.

15. Upon removal of the interim loan costs from the revenue requirement by DWR, if these sums are not needed to pay interest on the long term bonds or to reimburse the General Fund, the Commission would expect to be able to implement a prompt adjustment to the DWR remittance charges payable by the utilities for the balance of 2002.

16. An interim arrangement calling for utilities to remit franchise fees on DWR power sales should be adopted to provide for municipalities to continue to receive such fees pending further determination of a proper disposition of this issue.

17. The record should be further developed concerning the rights and obligations of municipalities, DWR, and the utilities with respect to the collection and remittance of franchise fees associated with DWR power sales. The ALJ should issue a procedural ruling to solicit further comments for this purpose.

18. The servicing agreements approved for SDG&E and SCE should be applied in prescribing the manner of billing, collection, and remittance to be followed by each of those respective utilities with respect to DWR charges implemented in this order.

19. While the servicing agreement for PG&E has not been approved by the Bankruptcy Court, the pertinent language from its servicing agreement as identified in the ALJ ruling dated December 6, 2001, forms a reasonable basis for prescribing the manner of billing, collection, and remittance to be followed by PG&E with respect to DWR charges implemented in this order.

20. PG&E should also be remitting revenues to DWR for Imbalance Energy in that DWR is responsible for such charges according to the order of the FERC.

21. The impacts of Direct Access customers' responsibility for a share of the DWR revenue requirement allocation has not been reflected in the amounts presented in this order, but the assessment of those potential impacts should be considered in this docket on a timely basis in coordination with A. 98-07-003.

22. In order to facilitate independent charges that will be segregated and remitted directly to DWR, a separate per kWh charge should be used in computing the revenue to be forwarded to DWR by each utility on a monthly basis.

23. To ensure that the utility recovers neither more nor less than it would otherwise recover under its imputed utility rate, the utilities should be authorized to establish interest-bearing balancing accounts as a provision of their filed tariffs.

24. The utilities continue to have the obligation to serve pursuant to Public Utilities Code § 451 and Water Code Section 80002.

O R D E R

IT IS ORDERED that:

1. The revenue requirement of the California Department of Water (DWR) in the amount of $10,003,461,000 (as set forth in Appendix A) is hereby implemented as provided in the following ordering paragraphs, covering the period January 17, 2001 through December 31, 2002.

2. The total DWR revenue requirement is hereby allocated among the customers in the service territories of three major utilities as follows: for the service territory of Pacific Gas and Electric Company (PG&E) in the amount of $4,765,407;000 for the service territory of Southern California Edison Company (SCE) in the amount of $3,674,066,000; and the remaining allocation to the service territory of San Diego Gas and Electric Company (SDG&E) in the amount of $1,536,989,000.

3. PG&E, SCE, and SDG&E are directed to begin disbursement of proceeds to DWR, as required by their respective servicing agreements or commission order, using the respective charges in cents per kWh of 10.047 for PG&E, 10.309 for SCE and 9.947 for SDG&E. These charges shall apply to each DWR-supplied kWh included on bills rendered on or after March 1, 2002.

4. The cents per kWh charges referenced in ordering paragraph 3 above shall remain in effect for each utility through December 31, 2002 (unless DWR

indicates an earlier adjustment is needed), and shall provide recovery of the DWR revenue requirement applicable through that period. Updated DWR charges shall be scheduled to take effect for customers in each of the utilities' service territories beginning on January 1, 2003, covering the DWR revenue requirement for the forecast period from January 1, 2003 through December 31, 2003.

5. To the extent it has not already done so, each utility shall remit an additional one time lump sum payment to DWR representing DWR power delivered to that utility's customers and billed prior to March 1, 2002. The one-time payments shall be based on the difference between the applicable interim charges that have already been remitted to DWR and the amounts that are due based on the DWR revenue requirement allocated to each utility through March 1, 2002. The utilities shall forward the lump sum payments to DWR within 30 calendar days of the effective date of this order. All other sums to be forwarded to DWR pursuant to this ordering paragraph shall be sent at the time specified in the servicing agreement with which the Commission has ordered the utilities to comply.

6. In the case of PG&E, because its servicing agreement has not been approved by the Bankruptcy Court, PG&E shall remit payments in accordance with the provisions based on excerpts from its servicing agreement as set forth in the ALJ ruling dated December 6, 2001, except that PG&E shall also be required to account for and remit to DWR past amounts owing relating to Imbalance Energy.

7. Each of the three utilities shall establish interest-bearing balancing accounts to provide for segregation of DWR-related billed revenues from URG-related billed revenues. The balancing account shall be credited with revenues based on DWR-related kwhr sales multiplied by the adopted DWR charge per

kwhr set forth in this order. The balancing shall be debited with the allocated share of actual costs as determined by DWR in its periodic updates of revenue requirement. The share of under or overcollection in DWR costs shall be chargeable to customers in each utility service territory based upon the adopted percentage allocation adopted in this order multiplied by the total actual under or overcollection.

8. The under or overcollection in the account shall be determined as the difference between (a) the total DWR revenues billed, collected, and remitted to DWR and (b) the share of actual DWR costs allocated to the utility. The balancing accounts shall be trued up, pursuant to a subsequent Commission order, no later than during the next update proceeding for DWR.

9. The schedule for the next update of DWR revenue requirement shall be set to begin June 1, 2002, with DWR charges to be revised effective January 1, 2003. The Commission or the ALJ shall issue further orders or rulings establishing any necessary provisions as to the manner and process for the DWR revenue requirement update proceeding.

10. The assigned ALJ shall issue a procedural ruling calling for further briefing and comments regarding pertinent legal issues as to the rights and obligations of municipalities, utilities and their customers, and DWR with respect to the billing, collection, and remittance of franchise fees associated with DWR electric power sales.

11. The ALJ shall issue any further rulings as necessary to expedite consideration of issues relating to Direct Access Customers' cost responsibility for DWR revenue requirements, including any associated adjustments to the adopted DWR allocation percentages as may be relevant to recognize Direct Access impacts.

This order is effective today.

Dated ________________________, at San Francisco, California.

Appendix A

Table 1

DWR Revenue Requirement

For the Period January 17, 2001 through December 31, 2002

($000s)

Quarter	Retail Sales (GWhs)	A&G	Other	DSM	Contract Power	Residual Net Short	Ancillary Services	Total Commitments	(Lag) Lead Accrual to Cash	Total Operating Expenditures	Financing Cost	Total Expenditures	Revenue Lead (Lag)	Spot Sales Revenue	Estimated Quarterly Fund Balance	Total DWR Revenues Needed	Net Borrowed Proceeds	Customer Revenue Requirement
		A	B	C	D	E	F	G (Sum of A thru F)	H	I (= G + H)	J	K (= I + J)	L	M	N	O (=K – L – M + N)	P	Q (=O – P)
Q1, 2001	12,360	7,848	-	-	-	3,581,465	367,847	3,957,160	(1,619,382)	2,337,778	-	2,337,778	(544,097)	-	293,176	3,175,051	2,400,000	775,051
Q2, 2001	19,620	10,162	-	482	627,601	3,884,229	419,215	4,941,690	6,302	4,947,991	-	4,947,991	(1,030,866)	-	4,239,624	9,925,305	7,908,729	2,016,576
Q3, 2001	16,054	11,346	3,734	226,446	888,404	1,135,727	57,667	2,323,324	(55,479)	2,267,845	(10,481)	2,257,364	(329,133)	-	3,182,822	1,529,696	(116,300)	1,645,996
Q4, 2001	10,365	8,998	4,008	61,968	670,470	248,590	43,889	1,037,923	550,427	1,588,350	-	1,588,350	223,483	20,884	2,963,069	1,124,230	-	1,124,230
Q1, 2002	9,313	15,104	3,667	-	652,644	169,756	51,551	892,722	1,543,844	2,436,567	(45,976)	2,390,591	879,565	24,819	2,499,879	1,023,017	-	1,023,017
Q2, 2002	7,957	15,104	3,211	-	665,651	129,830	42,678	856,474	(19,771)	836,703	471,932	1,308,635	20,355	39,279	2,128,890	878,012	-	878,012
Q3, 2002	12,312	15,104	4,895	-	946,735	220,184	64,080	1,250,998	(25,251)	1,225,748	400,807	1,626,555	(257,440)	45,879	1,643,471	1,352,697	-	1,352,697
Q4, 2002	10,812	15,104	4,249	-	832,758	164,417	54,752	1,071,280	20,493	1,091,773	464,959	1,556,732	194,995	26,043	1,495,658	1,187,882	-	1,187,882
Total	98,793	98,771	23,764	288,896	5,284,264	9,534,199	1,101,678	16,331,571	401,184	16,732,755	1,281,242	18,013,997	(843,139)	156,903		20,195,890	10,192,429	10,003,461

Notes

1. **Total Commitments** equals sum of **A&G**, **Other (Uncollectables)**, **DSM**, **Contract Power**, **Residual Net Short**, and **Ancillary Services**
2. **Total Operating Expenditures** equals **Total Commitments** plus **(Lag) Lead Accrual to Cash**
3. **Total Expenditures** equals **Total Operating Expenditures** plus **Financing Cost**
4. **Total DWR Revenues Needed** equals **Total Expenditures** minus **Revenue Lead (Lag)**, minus **Spot Sales Revenue**, plus **Estimated Quarterly Fund Balance**
5. **Customer Revenue Requirement** equals **Total DWR Revenues Needed** minus **Net Borrowed Proceeds**

(END OF APPENDIX A)

Appendix B

Summary of Parties' Comments Regarding the Reasonableness of DWR's Revenue Requirement

This appendix sets forth parties' position regarding various concerns raised in their comments filed on November 13, 2001 regarding their review of the DWR revenue requirement submittal of November 5, 2001. In response to a letter of Commissioner Brown to DWR dated, DWR provided further responses to the concerns raised by parties, as summarized below. These comments are provided for informational purposes, with the understanding that DWR retains responsibility for conducting a "just and reasonable" review of its costs pursuant to Public Utilities Code Section 451.

1. DWR Losses on Surplus Power Sales

DWR's revenue requirements include costs associated with surplus power that is sold off-system. PG&E argues that under Water Code Section 80116, DWR may not charge retail end-use customers for losses incurred on off-system sales of surplus power because retail end-use customers are only liable for the costs of the power actually sold to them.

DWR states that it is impossible to identify which specific purchases by DWR are subsequently sold off system to non utility customers, precluding DWR from quantifying a true "cost" of surplus power. DWR did provide, however, a weighted average monthly summary through September 2001 and quarterly thereafter of cost and volume of long term power, residual net short purchases, and off-system sales.

DWR disagrees with PG&E's characterization of any DWR purchases as being made for any purpose other than for the provision of the utilities net short position. DWR explains that from time to time, it may purchase more energy than is currently required to serve retail customers net short. The excess energy is sold into wholesale markets to provide off system revenues which are used to decrease revenue requirements recovered from retail customers. DWR states that such balancing of needs by periodic off system sales is standard industry practice. Therefore, DWR asserts that it is appropriate to consider all purchased power costs (including losses) incurred in DWR's revenue requirement.

2. Spot Electricity Prices in Q3-2001

PG&E has noted that DWR's estimate of spot electricity prices for Q-3 in the November 5 Revenue Requirement (Table 6, pg. 16) of $117MWH price is significantly above the FERC-mandated price cap in effect during Q3- 2001. PG&E claims that DWR's Q3-2001 prices are inflated by as much as $700 Million due to this effect.

PG&E asked that DWR explain the re-classification of its short-term contracts (90-days or less) that are now part of the "Residual Net Short," and indicate to what extent these 90-day contracts have caused the residual net short average costs to exceed the FERC price cap during third quarter 2001. PG&E asked that DWR provide detailed workpapers regarding the dates, amounts and costs of such 90-day contracts entered into during the period immediately prior to and during third quarter 2001, especially after adoption of FERC's price mitigation order.

In its December 13 reply, DWR explains that it has not reclassified short term contracts, nor are the 90-day contracts responsible for the residual net short average to rise above the FERC price cap. In its reply, DWR provides a table summarizing the prices and volumes for components of the net short by month during third quarter 2001. DWR explains that actual purchases in each of the spot markets are all below the current FERC non-Stage 1 alert price cap of $101.06/mWh. Yet, in computing its reported third quarter prices, DWR includes the net effects of off-system sales, causing reported unit prices to exceed the FERC price cap in the month of July 2001.

3. Line Losses

PG&E claimed that the 9% assumed by the DWR for PG&E's transmission and distribution losses should be reduced to no more than 6.4%. PG&E assumes a 0.6% reduction of transmission losses due to the fact that the ISO typically requires generators to make up the associated transmission losses. PG&E claims that DWR's revenue requirement constitutes double-charging of PG&E customers by about $390 Million because it includes ISO's Unaccounted-for Energy (UFE) charges for PG&E, but also assumes additional energy is procured by DWR for UFE.

DWR disagrees with PG&E's contention that line losses should be reduced to 6.4% and denies any double counting of UFE charges. DWR states that the fact that the ISO requires generators to make up line losses does not mean that losses do not occur, or that DWR does not incur costs for associated energy to account for those line losses. DWR further states that no explicit UFE charges were considered in the revenue requirement after August 2001. UFE amounts are inherently included as part of the forecast of energy procured by DWR.

4. Direct Access Estimates for PG&E

In its October 26 comments to DWR, PG&E provided updated estimates for the fourth quarter of 2001 for direct access, although DWR has not incorporated PG&E's update in its latest revenue requirement. However, PG&E now believes that the actual direct access amount for the fourth quarter of 2001 and for all of 2002 will be even higher than previously forecasted.

DWR states that it cannot confirm with reasonable certainty PG&E's estimates of direct access. Because of the multiple uncertainties surrounding the future of direct access, DWR does not believe it is appropriate at this time to alter its estimates of direct access based on more recent estimates. DWR states that it will consider expected changes to California's retail electricity markets when developing its next determination of revenue requirements.

5. WAPA Loads

PG&E claims that DWR's estimate of Western Area Power Administration (WAPA) loads of 5,429 GWh is too high. PG&E provided DWR an estimate of 5,026 GWh for 2001 and 3,837 GWh for 2002 for WAPA loads in its October 26 comments, corresponding to a reduction in DWR's revenue requirement for PG&E by about $90 Million.

DWR states that it will continue to review PG&E's updated WAPA load estimates and incorporate any changes in DWR's true up process relating to updating its future determinations of revenue requirement.

6. Treatment of Wholesale Contracts

SCE questions whether DWR has been consistent in its treatment of SCE's wholesale contract obligations, in particular, SCE's exchange contracts, or whether these contracts were considered in estimating SCE's net short position.

DWR asserts that it has been consistent in its treatment of wholesale obligations and exchanges between the three utilities. DWR explains that many of the utility-to-municipal exchanges are included within the PROSYM simulations. While other exchanges are not explicitly modeled within PROSYM, they are included in DWR's true up to actual costs.

7. Short-Term Load Resource Balance

On page A-20 of its revenue requirement submittal, DWR notes that it is limiting imports into California to generation owned by the utilities as part of their retained generation, out-of-state generation owned by municipal utilities, or existing bilateral contracts with out-of-state suppliers. PG&E has claimed that this understates the amount of power that could be imported into California.

DWR responds that PG&E misinterprets the explanatory notes to Table III-1 in the November 5 Determination. DWR is not limiting its power procurement only to new, in-state generation without consideration of imports. Table III-1 is indicative of resources firmly committed to consumers in California at the summer peak hour over DWR's revenue requirement period. DWR states that other, non-firm, out-of-state resources expected to be available have been incorporated into its estimates of power to meet net short requirements.

8. DWR Reserve Requirements

DWR revenue requirements include cash to fund reserve requirements. According to DWR, the cash reserves are needed for debt service reserves and for handling future cost and revenue volatility under different "stress scenarios" involving variations in natural gas and spot market prices, and forced outages at generating plants.

Aglet observes that DWR's reserve requirements are large compared to normal utility working cash requirements, and argues that the Commission should not require utility customers to fund any DWR cash reserve requirements. Aglet claims there are better ways to protect DWR from cash flow volatility. Aglet argues that for large firms, and by extension for DWR, the preferred response to operating volatility is the use of credit facilities—not cash reserves. Creditworthy utilities respond to cost volatility by relying on lines of credit, commercial paper and other short-term borrowing and lending. Aglet believes the Commission and DWR should cooperatively seek a "line of credit" or equivalent financial backup from the State.

If the Commission insists that customers put up the requested cash reserves, then Aglet argues that customers should be credited with interest accruals on the full amount of the DWR's cash reserve, consistent with rate base reductions ordered for utilities with contributions in aid of construction. Aglet asks the Commission to encourage DWR to return unneeded reserves to customers promptly after the State issues its bonds and in any other circumstance where DWR recognizes that its cash flows will become less volatile.

9. Uncollectibles Factor

DWR includes in its revenue requirement an allowance for uncollectibles, based on a factor of 0.0033. (Reference Item E, transcript of October 22, 2001 workshop, RT 81:22-82:12.) Aglet opposes DWR cost recovery of uncollectibles based on the untested average rate of 0.0033, but instead advocates use of the most recently authorized uncollectibles factor for each utility. For example, the authorized factor for PG&E is 0.00267, which is 19% lower than DWR's figure. (Decision 01-10-031, Ordering Paragraph 27, slip op. at 45.)

Aglet argues that reliance on Commission-authorized uncollectibles factors will treat customers fairly and will have no effect on DWR's achieved revenues. Customer rates for each utility would include an uncollectibles allowance based on the authorized rate, billed revenues would be reduced using the authorized rate, and remaining cash revenues would be available for transmittal to DWR. Aglet argues that this outcome is administratively efficient because each utility will use a single uncollectibles factor for all of its retail rates, rather than determining rates based on two different factors.

DWR has explained that its forecasted allowance for uncollectibles was developed assuming a pro rata share of recently observed utility uncollectible accounts. (Reference Item C, DWR, November 5 revenue requirement document, p. 19.) As stated previously, DWR is charged with determining the justness and reasonableness of its revenue requirement, and this proceeding is not the forum in which to litigate the reasonableness of DWR's determination of this element of its revenue requirements. In the true up of DWR's forcasted versus actual revenue requirement, relevant differences in uncollectibles expense can be taken into account.

(END OF APPENDIX B)

Appendix C

Natural Gas Pricing Assumptions

Natural gas prices are an input in DWR's estimated power prices in meeting utility customers' net short requirements. DWR provides a detailed discussion of its assumptions underlying natural gas prices in Appendix VI of its November 5th submittal. Estimated prices have been developed using a proprietary forecasting model developed by Navigant.

The Appendix C Table below shows the cost of natural gas assumed in the development of both contract power costs as well as the cost of residual net short power resources for the DWR revenue requirement. Fuel transportation charges are estimated in DWR's generation dispatch model based upon regional location of generating sources. During the summer of 2001, minor volumes of gas were procured for part of 2001 and the first quarter of 2002 for some of those contracts under which DWR has rights to purchase or supply fuel to a generator. Those costs are included in DWR's contract energy costs. All fuel costs included in the contracts and the spot market purchases are assumed to be equal to the average spot market price of natural gas.

TABLE
GAS PRICE ASSUMPTIONS
($/MMBTU IN 2001 DOLLARS)

	SoCal Border	Malin	PG&E City Gate
Q3 2001	3.72	3.59	3.87
Q4 2001	3.54	3.01	3.49
Q12002	3.55	3.02	3.51
Q2 2002	3.52	2.99	3.47
Q3 2002	3.36	2.86	3.33
Q4 2002	3.78	3.22	3.72

(END OF APPENDIX C)

**************APPENDIX D (SERVICE LIST) *************

Last Update on 03-JAN-2002 by: LIL

A0011038 LIST

A0011056/A0010028

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