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Decision 96-10-074 October 25, 1996

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation.	R.94-04-031 (Filed April 20, 1994)
Order Instituting Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation.	I.94-04-032 (Filed April 20, 1994)

OPINION ORDERING SEPARATION OF TRANSMISSION FROM DISTRIBUTION COSTS AND REQUESTING COMMENT ON RELATED ITEMS

Summary

In this decision, we direct Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E) to provide by November 15 a separation of its ratebase and revenue requirement into generation, transmission, and distribution if Federal Energy Regulatory Commission (FERC) has responded to the utilities' request for Declaratory Order filed last April 29. This decision also asks the utilities and other parties to comment on alternative strategies for metering and billing under Direct Access, particularly when hourly meters are installed. This decision directs the utilities to provide incremental cost information. We ask all parties to take into careful consideration the recent changes in State legislation enacted under AB 1890.

Background

On August 26, 1996, the Ratesetting Working Group filed its Unbundling Report in response to Commissioner Duque's June 21

1996 Assigned Commissioner's Ruling in the ratesetting area. In the ruling Commissioner Duque asked the Working Group to identify the extent of unbundling required by January 1, 1998 to support direct access. The Working Group parties did not reach agreement on the necessary level of unbundling and instead submitted this report. The report presents five options for unbundling utility functions to facilitate consumer choice and identifies several policy issues the Commission should consider in reaching a decision on the extent of unbundling required to facilitate consumer choice. The report specifically requests guidance from the Commission concerning distribution unbundling.

In a ruling dated August 14, 1996, Commissioner Duque granted a request of various parties to provide comments on the report. The following parties served comments on September 13, 1996: California Energy Commission (CEC), California Farm Bureau Federation (Farm Bureau), California Industrial Users (CIU), California Large Energy Consumers Association and California Manufacturers Association (CLECA/CMA), Cellnet Data Systems, Inc. (Cellnet), Division of Ratepayer Advocates (DRA), PG&E, SDG&E, SCE, and Toward Utility Rate Normalization and Utility Consumers Action Network (TURN/UCAN). In addition, a coalition of twelve parties sent a letter to Commissioner Duque on September 13 supporting aggressive unbundling of distribution services in California by January 1, 1998. [1]

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1 The signatories to the letter were SDG&E, Agland Energy Services, Inc., Enron Capital & Trade Resources, Illinova Energy Partners, School Project for Utility Rate Reduction, Regional Energy Management Coalition, Destec Power Services, The Utility Solutions Partnership, Inc., California League of Food Processors, Working Assets, New Energy Ventures, Consumers Association, Shareplus, and Association of Bay Area Governments.

Summary of Five Options: Similarities and Differences

The parties participating in the Ratesetting Working Group agree that at a minimum, generation, transmission (including ancillary services), distribution, transition costs and public goods costs should be unbundled by January 1, 1998. Parties do not agree whether certain costs such as billing and meter reading should be separately identified or whether additional distribution service unbundling is necessary to support consumer choice. The five options included in the report capture a range of possible outcomes regarding the extent to which any additional unbundling might occur, and when these additional products and services might be unbundled. (See page 5, Unbundling Report.)

Each option is sponsored by one party. Options 1 and 2 would limit unbundling prior to January 1, 1998 to the five consensus items whereas Options 3 and 4 would begin the process of distribution unbundling so that a limited number of distribution services could be unbundled prior to January 1, 1998. Option 5 advocates commitment to a more extensive unbundling of distribution services without requiring specific timing of this action.

Option 1 would defer discussion of additional unbundling until after direct access has commenced. Option 2 would begin the process of identifying additional distribution services for unbundling and necessary cost studies prior to commencement of direct access, but would not actually unbundle such costs until after January 1, 1998. Option 3 supports unbundling metering, billing, customer and uncollectibles services by January 1, 1998 in order to ensure timely direct access and to support entry of new providers, and then unbundling of other services by 1999. Option 3 also promotes a particular methodology for arriving at utility cost credits for unbundled services that are provided by competitors. Option 4 supports unbundling competitive and monopoly prices and providing for different quality levels but would maintain the utility distribution company as the exclusive provider in the near term. Rather than focusing on unbundling distribution services, Option 5 advocates unbundling certain elements of the monopoly wires business by changing the way the utility distribution company is regulated, how they earn profits, and how distribution assets are financed.

<u>Comments of Parties</u>

The CEC staff developed Option 4 and the CEC endorsed Option 4. In its comments it reiterates that the CEC defines unbundling to mean the identification and separation of particular services and their costs, but does not immediately require the unbundled components to be subject to competition. The CEC believes that Option 1 is inconsistent with both Decision (D.) 95-12-063 and D.96-03-022 and that precluding implementation of any unbundled services until after January 1, 1998, as Option 2 would, will retard development of energy service providers.

Farm Bureau believes the Commission must "order that specified utility distribution services begin to be unbundled immediately... in order for aggregation services to be available to small customers as of January 1, 1998." (Comments of Farm Bureau, p. 3.) Farm Bureau recommends rejection of Options 1 and 2.

CIU believes that "it is important that the unbundling process be expedited and that every effort be made to accomplish some measure of unbundling of distribution services by 1/1/98." (Comments of CIU, pp. 3-4.) CIU does not agree though, that distribution service unbundling is needed for benefits of competition to flow to all customers.

CLECA/CMA support either Option 1 or Option 2 because they believe that efforts to further unbundle distribution services are likely to prevent achievement of the January 1, 1998 implementation date, and/or will cause further unbundling to be performed in a "haphazard and unacceptable manner." (Comments of CLECA/CMA, p. 2.) CLECA/CMA does support further work on unbundling with the goal of prompt completion after January 1, 1998.

Cellnet does not comment on the options presented in the report but instead recommends a test to assist the Commission in determining whether certain services should be unbundled from the distribution monopoly. Cellnet's test looks at whether equipment, facilities, processes, or services are shared by or affect multiple users.

DRA argues that the Commission can and should demonstrate its commitment to make competitive choice a realistic opportunity for all customer classes by requiring additional rate unbundling beyond the five consensus items by January 1, 1998. DRA states that "[u]nbundling customer service functions is necessary not only to facilitate the offering of competitive options to all customer classes, but also to ensure equal opportunities for new marketers to compete with the Utility Distribution Company (UDC) for retail sales." (Comments of DRA, pp. 2-3.) Customer service functions are defined to include, among other elements, billing, metering, customer information, and collections.

PG&E is the proponent of Option 2. PG&E believes that customer choice for electric generation services is distinct from customer choice for distribution services and that further distribution unbundling is not necessary to allow retail customers to enter into direct transactions for electric generation. PG&E objects to the methodological approach, including regulatory procedures, set forth in Option 3. PG&E states that much of the argument in Option 4 supports PG&E's cautious approach and that Option 4 does not even recommend having the unbundled services be competitively provided.

SDG&E is the proponent of Option 3. SDG&E believes that Option 3 represents what is necessary and achievable to meet the Commission's objectives while balancing the interests of customers and retailers. In SDG&E's opinion, limiting unbundling to the five consensus items "will prevent emerging retailers from offering residential and small commercial customers meaningful choices under direct access." (Comments of SDG&E, p. 2.) SDG&E believes Option 3 is superior to Option 4 because Option 3 allows retailers the option to competitively supply services that are unbundled. SDG&E notes similarities between Option 5 and Option 3 but does not support the Option 5 recommendation that would cause major changes to regulation and ratemaking practices.

SCE is the proponent of Option 1. SCE believes that Option 1 will facilitate an orderly transition to a deregulated electric generation market while maintaining system reliability. In SCE's opinion, the other options would move too quickly, "jeopardizing the direct access timetable" (Comments of SCE, Executive Summary, p. 2) and have the potential to compromise system reliability and consumer protection, and could lead to unnecessary consumer confusion.

TURN/UCAN state that if the Commission's desire is to maximize opportunities for all customers to engage in and benefit from direct access transactions, the Commission must reject Options 1 and 2. TURN/UCAN state that although they are somewhat skeptical of the degree to which benefits will accrue to smaller customers, they "firmly believe that the unbundling of distribution services must be pursued to determine just what benefits can be achieved through the effort." (Comments of TURN/UCAN, p. 2.) Finally, TURN/UCAN points out that limited distribution service unbundling has already occurred citing as one of the best examples that SCE currently provides natural gas and water meter reading services to non-utility customers in the city of Long Beach.

<u>Discussion</u>

A. <u>Implications of Parties' Concerns</u>

When a business bundles its costs, it offers various activities and services for a single price. When a business unbundles its costs, it separately identifies those costs related to various activities or services, which makes it possible to do several things. Service providers could present bills that separately list charges related to each cost factor. Providers could elect to purchase specific services from each other. Conversely, providers could elect not to purchase certain services from each other in the hopes of reducing overall cost.

What we face here may appear simply to be a procedural question: when should the Commission address various issues related to electric rate unbundling? However, the way we answer this question may affect the ability of many customers to have direct access to competitive generating services in 1998. For the provision of electricity, the failure to separately price and offer some services might severely restrict the ability of firms to compete for low-volume customers (residential and small business) and might effectively preclude those customers from gaining direct access to competitive generation. However, the failure to separately price and offer other services might have no effect on competition.

Participants in the Ratesetting Working Group and those commenting on the August 26, 1996 report disagree as to which services must be unbundled in order to foster direct access for all customers on January 1, 1998. Because we have not held hearings or undertaken a factual inquiry, we are not equipped to determine who is right and who is wrong. In addition, some parties assert that there is not enough time to identify and quantify more than five major cost categories before the initial offering of direct access in 1998. However, here is a striking example of a situation where "to not decide is to decide." If we allow the distribution utilities to lump various costs into a single distribution charge while we undertake a more leisurely study two or more years from now, some conditions are certain to apply when the "direct access" bell rings forth in January 1998. If the distribution utility does not separately charge for billing services, a competing energy provider, which chooses to directly bill its customers, may encumber those customers with duplicative billing costs. If the utility does not separately charge for metering and meter reading, then a competitor who may rely on innovative metering technologies or remote meter reading may be unable to offer those services, or may be forced to saddle the customer with further duplicative costs. If the cost of collections and uncollectibles is included in the distribution charge, then a competitor who can successfully improve the rate of payment through direct deposit or other mechanisms may be unable to bring the resulting benefits to its customers. Several parties refer to these as "revenue cycle" costs and suggest that by unbundling them, the Commission can improve the likelihood that direct access will be available to customers in all classes by January 1, 1998.

Without a factual inquiry, we do not know if various parties are right when they assert that the failure to separately charge for such "revenue cycle" activities will result in an absence of meaningful direct access opportunities for residential and small business customers. However, it is possible that such costs will be a proportionately greater share of the cost of serving smaller volume customers and that if those costs remain fixed, there will be less of an opportunity for a firm to profit while providing service at a competitively attractive price. For these reasons, we remain concerned about unbundling certain "revenue cycle" costs by January 1, 1998 could affect the provision of direct access opportunities to residential and small business customers.

We note that in a ruling issued May 8, 1996, Commissioner Duque recognized that these "revenue cycle" costs do not fit neatly into any of the broader unbundling categories. He said:

> The vertically integrated utility undertakes many activities which have no unique relationship to any of the three functional areas (generation, transmission or distribution). As the most prominent example,

the utility undertakes administrative and general activities with substantial fixed and variable costs to manage its operations. Other examples include customer service and support, meter reading and billing as well as regulatory activities."

He asked the parties to consider the most appropriate way to allocate these costs across the three functional areas. Instead, some parties have proposed including some of these non-unique charges as distribution costs. We agree with the distinctions suggested by Commissioner Duque and are concerned that the approach taken by some parties may have skewed the debate. By treating "revenue cycle" costs as if they were part of the distribution system, it has become easy to think of separate identification of those costs as if it required unbundling of the distribution costs. We are not ordering any unbundling of the distribution system at this time.

B. Request for Comments

Our Preferred Policy Decision in electric restructuring (D.95-12-063 as modified by D.96-01-009) focused on the potential for competitive entry in the generation market. Our decision did recognize that because the utilities currently bundle generation, transmission, and distribution services, a potential energy provider cannot enter the generation market without the utilities unbundling generation from transmission and distribution. This unbundling creates a major transformation of the electric power industry. Although we did not order unbundling within generation, transmission, or distribution services, we did recognize the key role of specific support functions like metering for Direct Access generation and the availability of customer information for billing.

In their November 15 filings, PG&E, SCE, and SDG&E will each provide a separation of its ratebase and base rate revenue requirement into transmission and distribution if FERC has approved their April 29 request for a Declaratory Order to separate transmission and distribution facilities. These filings will reflect the effect of the FERC Order, all applicable statutes, including AB 1890 and our prior decisions. Each utility must also show its total ratebase and revenue requirement as last authorized in our decisions with clear explanations for any changes since last authorized and explain rules used to allocate this ratebase and revenue requirement between transmission and distribution. If the FERC Order approves a separation which differs from the April 29 request, we will extend the November 15 filing date by 30 days from the date of the FERC Order.

Our Preferred Policy Decision did describe the key role of customer choice in the energy market. This decision described two options for customers: the Power Exchange and Direct Access. The Power Exchange will set hourly prices for energy, and hourly prices will characterize many contracts in the competing Direct Access market. Those customers buying at hourly rates will require hourly meters to measure hourly usage, but few customers now have such meters. (Customers might participate indirectly in the hourly market through use of representative load profiles, but a representative load profile allows the opportunity for gaming by both buyer and seller and does not reflect the customer's demand response to the hourly price.) Of course, not all customers of the Power Exchange or Direct Access market will pay hourly prices because customers can choose bundled service from the distribution utility with the energy price averaged over the billing month and some Direct Access customers could find generation suppliers who will sell at an average price.

Currently, a typical customer of a vertically-integrated electric utility has a single meter, which measures cumulative use, and receives one monthly bill for combined generation, transmission, and distribution services. With choice of Direct Access, the customer can receive its energy from one provider while it receives transmission and distribution (T&D) services from others, which raises the issue of metering and billing for each provider. Direct Access billed at hourly rates raises the additional issue of the installation of an hourly meter. The utilities impose a usage rate to pay for T&D services, but usage metering for T&D service would be unnecessary if the utility imposed only a fixed charge rate, given the substantial fixed cost nature of T&D service. (We refer to T&D service together for simplicity although we expect separation of transmission from distribution service.)

A meter which records hourly usage can replace an existing meter or can supplement it if the existing meter remains in place. With the latter alternative of two meters, the hourly meter can record for both usage billed T&D as well as hourly priced energy, but using the existing meter to record usage for T&D services allows independent metering by two providers. With the single meter in the former alternative, one meter must record usage jointly for both energy and T&D services. If a provider owns the meter, a single meter measuring usage for several services creates an unusual situation where one firm must rely on another, possibly competing, firm to measure its sales. In retail business, seldom does one firm trust another to record and process its point-of-sale transactions while few firms, if any, will allow a competitor to record and bill such transactions. Not only does common transaction processing create security and confidentiality issues, it also requires the potentially contentious allocation of common costs to price the transaction service to each firm.

In retail electric service, the continuation of usage billing for T&D as well as energy creates the potentially unusual situation where a single meter can measure usage for different services provided by different firms. (Existing technology can allow independent access of the recorded usage data by each firm.) This situation occurs if the Direct Access provider meters for T&D

as well as energy or if the T&D utility meters for energy as well as T&D services. This situation does not occur if a customer wants hourly billing from the Power Exchange provided by the distribution utility. Eventually, the T&D utility, which provides a fixed cost service, could collect its costs through only fixed charges which would, in turn, eliminate the requirement for usage metering for T&D. However, even if this occurs, AB 1890 mandates that the customer must still pay the CTC, at least partly based on a usage rate, directly to the distribution utility.

In the discussion below, we describe three near term strategies and a flexible longer term strategy to provide hourly metering and billing for Direct Access customers. We request comments on these strategies and invite parties to propose other strategies if they believe such strategies more effectively meet our objective. In this discussion, we first state our objective, note the importance of clear definition of metering and billing functions, review seven significant issues which will affect the evaluation of any strategy and then describe these strategies.

We ask parties to evaluate strategies given our objective in this proceeding of not impeding the prompt availability of Direct Access to all customers while protecting the integrity of the metering and billing process and offering a level playing field. By level playing field, we mean not only that parties have comparable access to the generation market through metering and billing but also that such access implies fairness to all stakeholders which avoids cost shifting where, for example, lower costs to one group do not mean stranded costs borne by another. A party should comment separately if it believes that the objective of the promotion of Direct Access requires a separate evaluation of any strategy. At this state of the proceeding, our objective for providing hourly billing is dependent on our objective for Direct Access availability and we are not adopting an independent objective of providing unbundled metering or billing services.

other words, we are not proposing competition in metering and billing as an objective in itself but as a means to achieve effective competition in Direct Access.

The scope of the discussion below includes both metering and billing, but we recognize that each encompasses several functions. As an example, metering now includes data sampling and storage and even more broadly defined includes meter installation and maintenance. The meter site could soon include data transfer capability through telemetry as well as load control through local or remote intelligence. Billing includes functions in the bill cycle such as bill preparation, submission, payment receipt, and record keeping while credit extension, bill consolidation, credit collection, and customers support offer separate functions. However, because parties can define the scope of these functions differently, we ask all parties to define precisely the metering and billing functions to which they refer.

We turn now to the issues. Many issues arise in the provision of metering and billing in the prospective industry structure, but we pose seven issues for review. In evaluating strategies, we request that parties comment on these issues: meter ownership, data access, meter installation, the potential extent of competition in metering and billing, estimates of meter cost, bill consolidation and cost, and the impact of the standardization of communication protocols for meters.

First, with respect to meter ownership, either the customer, generation provider, distribution utility, or another party could own the meter. Meter ownership implies an obligation to provide accurate data and to maintain the meter which becomes more important when a single meter provides service to several parties. An exclusive franchise whether held by a meter company or the distribution utility could mean lower unit costs but achieving least cost could limit customer choice of meter type in order to control data collection costs. In this decision, we emphasize that the choice to obtain any new meter will remain with the customer because we are not requiring customers on an individual basis to buy an hourly meter, taking into account the requirements in our Preferred Policy Decision.

Second, with respect to data access from a single meter, the owner or other permitted party could access the meter's data. However, multiple access creates problems of data confidentiality, transactions security and cost allocation for both metering and billing functions as discussed above. Again, these problems arise whether the Direct Access provider controls the meter or whether the distribution utility controls the meter.

Third, with respect to hourly meter installation, installation can occur individually when each customer decides to enter the hourly market or installation can occur system-wide under an exclusive franchise. The former maximizes customer choice while the latter allows universal Direct Access and offers possible economies of scale in both installation and operation of the metering and data transfer system.

Fourth, with respect to potential competition in metering and billing services, we ask parties to describe the conditions for open entry in these markets and any existing barriers to entry. We ask parties whether significant economies of scope exist between metering and billing or within each of these functions and whether significant economies of scale exist in either metering or billing functions. If a party concludes that the market is contestable in the sense that potential entry will drive price to incremental cost, describe why the Commission should not require the utilities to file incremental cost based rates.

Fifth, with respect to meter cost, we ask for parties' estimates of incremental cost of the hourly meter, a methodology to estimate potential cost credited to the hourly meter and the allocation of common costs with installation of a single meter. We recognize that the range of meter features, the nature and extent of the data collection network and the link to the billing services can cause a wide range in costs. However, we ask all parties to discuss whether a comprehensive program to retrofit existing meters for minimum hourly usage capability offers the lowest incremental cost option, particularly when linked with a telemetry network. Moreover, we ask all parties why we should not assume that the incremental cost for a given set of functions and features is identical across providers, in the absence of meter retrofit, if parties have access to a competitive market for the inputs to provide a metering service.

We require PG&E, SCE and SDG&E to provide by December 20, 1996, their estimates of the incremental cost for each major customer class on a per customer-month basis of hourly meters on both an individual and a system-wide basis. We also require an allocation of these incremental costs to generation, transmission and distribution services. We ask any other party who plans to offer meters to provide the incremental cost information by December 20, 1996 and to allocate these costs across the three services; we will assume that any party who does not provide such an estimate agrees that the incremental cost does not differ across providers and is lowest for system-wide installation of a meter retrofit. The estimate of incremental cost must include a clear definition of the proposed meter functions and features, and we request that a party provide at least one estimate which represents minimum meter functionality. We prefer use of publicly available price data in construction of these estimates although we will accept estimates for which the party claims confidentiality.

We also require PG&E, SCE, and SDG&E to describe the source of any utility cost credit, a methodology which defines precisely the data necessary to estimate this cost credit and a specific policy to allocate any stranded cost across stakeholders including ratepayers, employees, and shareholders. By cost credit we mean the cost which the utility will not incur if the utility or another party offers a billing or metering choice not now available from the utility. We ask other parties to provide this information about cost credits but we will assume any party who does not provide this cost credit information agrees that the credit is effectively zero. We also ask each party to provide a methodology to allocate any common credit across the billed services of generation, transmission, and distribution as well as CTC and the public good surcharge.

Sixth, with respect to bill consolidation and billing cost, we ask each party to describe procedures which will preserve data confidentiality and payment security with bill consolidation. We require PG&E, SCE, and SDG&E to provide by December 20, 1996 their estimates of the incremental cost on a per customer month basis of billing on both an individual and a system-wide basis. We require them to allocate these incremental costs to generation, transmission, and distribution services. We also ask any other party who plans to offer billing services to provide incremental cost information by December 20, 1996, and to allocate these costs across the three services; we will assume that any party who does not provide such an estimate agrees that the incremental cost does not differ across providers and is lowest for system-wide provision of billing service.

Seventh, with respect to technological developments, the market now offers both hourly meter retrofit devices and new hourly digital meters. We expect that with the expansion of entry in the generation market and greater customer participation in programs like Direct Access, the national market for meters will grow dramatically with likely declining unit costs and increasing features including load control at the meter site.

We support an open architecture with industry development of protocols which will standardize communication both with an external device/network for data collection and control as well as with an on-site bus/network for load control. Standardizing external communication will allow multiple service providers to access meter data with appropriate customer protection through, for example, data encoding. Standardization should encourage competition among meter providers to allow several vendors to sell within the network of one distribution company. Standardization is necessary in all integrated networks such as the local and long distance communication markets to allow multiple vendors to compete both within and across product lines. Intelligent meters could provide a standard command language to allow more flexible provider and customer control to respond to network prices or other conditions for load control. Eventually, such meters could interface with utility gas and water meters for remote data collection.

As a first strategy, assume installation of an hourly meter without replacement of an existing meter. This strategy means that the Direct Access provider and the T&D utility can meter and bill independently. This strategy allows customer choice and allows a level playing field for all buyers and sellers. Moreover, this strategy allows secure and confidential transactions for each firm and each customer. Also, this strategy does not require the contentious allocation of common metering and billing costs. Although this strategy implies some duplicate costs with two meters, the distribution utility can likely not avoid incurring any of its existing costs because it retains its existing metering and billing capability which, in turn, implies that it cannot credit the hourly meter with any avoided cost.

As a second strategy, assume that the hourly meter replaces the existing meter on an individual meter basis either as a retrofit or as a completely new unit. This strategy allows customer choice and does eliminate duplicate metering costs. However, a single meter will not allow the Direct Access provider and the distribution utility to meter independently unless the meter uses a standard communication protocol which allows at least these two providers to access the meter data. This strategy also requires the contentious allocation of common metering and billing costs. If the hourly meter uses telemetry, the distribution utility can likely avoid some meter reading costs; another cost credit could occur if the resale value of the replaced electromechanical meter exceeds its undepreciated book value.

As a third strategy, I assume that the hourly meter replaces the existing meter on a system-wide basis either as a retrofit or as a completely new unit. This strategy has nearly the same implications as the second strategy above except that the system-wide installation will likely reduce cost with economies of scope in the integration of the meter and data collection network.

The above strategies are all immediately available. The first strategy offsets the disadvantage of potentially higher unit cost with the advantage of secure and confidential transactions. The second strategy offers the advantage of somewhat lower unit cost with the disadvantage of joint use of data. The third strategy could lower unit costs relative to the second strategy. To resolve the conflict between duplicate cost and secure transactions requires use of technology which allows multiple provider access to usage data. Proposed strategies that entirely preclude the possibility of competitive entry will not be acceptable.

The key to a longer term strategy is allowing multiple provider access to data from a single meter. This resolves the dilemma noted above of allowing only one provider access to the meter data. In the discussion above, we mentioned the benefits of the standardization of communication protocols. With such an agreement, the industry can manufacture hourly meters with a range of features for multiple provider access and more importantly features for customer, provider or ISO load control. Moreover, this allows competition among manufacturers which should lower unit costs and increase feature availability. Therefore, the two essential elements of this longer term strategy are standardized communication and competition among meter providers.

Findings of Fact

1. In D.95-12-063 we recognized the need to unbundle generation, transmission, and distribution services to promote competition and mitigate market power.

2. In D.95-12-063 we adopted Direct Access and recognized the issues which Direct Access raised for both metering and billing, including the issue of hourly metering.

3. On April 29, PG&E, SCE, and SDG&E filed requests for a Declaratory Order with the FERC with their proposed guidelines to separate transmission from distribution.

Conclusions of Law

1. By November 15, PG&E, SCE, and SDG&E should file their total ratebase and base rate revenue requirement based on our last authorization and should separate this total between transmission and distribution, consistent with FERC orders.

2. By December 20, PG&E, SCE, and SDG&E should and other parties can provide their estimates of incremental cost of metering and billing given the objective and strategies which we describe.

3. By December 20, PG&E, SCE, and SDG&E should and other parties can provide their comments on other issues relating to meter ownership, data access, meter installation, the potential extent of competition in metering and billing, bill consolidation and the impact of the standardization of communication protocols for meters.

O R D E R

IT IS HEREBY ORDERED that:

1. By November 15, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) should file their total ratebase and base

rate revenue requirement based on our last authorization and should separate this total between transmission and distribution, consistent with Federal Energy Regulatory Commission orders.

2. By December 20, PG&E, SCE, and SDG&E should and other parties can provide their estimates of incremental cost of metering and billing given the objective and strategies which we describe.

3. By December 20, PG&E, SCE, and SDG&E should and other parties can provide their comments on other issues relating to meter ownership, data access, meter installation, the potential extent of competition in metering and billing, bill consolidation and the impact of the standardization of communication protocols for meters.

This order is effective today.

Dated October 25, 1996, at Sacramento, California.

P. GREGORY CONLON
President
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
Commissioners

Commissioner Daniel Wm. Fessler, being necessarily absent, did not participate.