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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)

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O P I N I O N

I. EXECUTIVE SUMMARY AND INTRODUCTION

Today's policy decision in context: On May 24 we advanced the policy deliberation phase of this proceeding by releasing for public comment two proposed sets of policy preferences enunciating views of a restructured electric services industry. Consistent with our unprecedented attempt to achieve the broadest base of public and stakeholder participation, we have held full panel hearings and received voluminous written comments on both sets of policy preferences. Most recently we used the vehicle of "Coordinating Commissioner Rulings" to pose questions and seek further clarification on critical points.[1] Having completed this deliberative phase of our proceeding we are now prepared to announce our policy decision.

A. Our Goal

In this opinion we advance a much matured description of market institutions and a much clearer view of the role of customer choice. The reader will find a more in depth discussion of both vertical and horizontal market power issues which must be resolved before either we or our counterparts at the Federal Energy Regulatory Commission can be expected to entrust the well

[1] This Rulemaking and its companion Investigation have attracted an extraordinary degree of formal participation. At last count four hundred ninety-seven persons and entities have become formal parties. The views and opinions of our fellow Californians were sought in a series of public participation hearings held across the state; our full panel hearings were broadcast on public access channels and carried by many of California's cable television operators. As a result of heightened public awareness, we have received hundreds of letters from individuals and benefitted from the organized views of many of California's vital communities such as the Latino Issues Forum, California/Nevada Community Action Association (Cal/Neva), the Greenlining Institute, Senior Utility Ratepayers of California, Inc., and the American Association of Retired Persons. Realizing that we could benefit from an even more broadly cast effort to receive views and opinions we dispensed with the need for formal party status in the first Ruling by the Coordinating Commissioner.

being of this state's economy to market forces. We build upon our call in May for an era of Cooperative Federalism to set forth the foundation of a California Consensus position on the structure of those institutions committed under our federal system to the stewardship of the national government.

The issues of transition cost, their identification, calculation and recovery are discussed from a policy perspective but also in sufficient detail to enable those with existing interests to determine our expectations respecting their opportunities and obligations as we work together to achieve a more sensible and sustainable future. Our objective continues to be the collection of transition costs through the imposition of a non-bypassable Competitive Transition Charge (CTC) that is competitively-neutral, fair to various classes of ratepayers and which does not increase rates beyond the revenue requirements we have established on January 1, 1996 without adjustment for inflation.

To assure the continued financial integrity of California's investor owned utilities, and give them an opportunity to be vital participants in the restructured market following the transition, we will allow them to recover 100% of the CTC. We propose to complete the valuation of the CTC by 2003, after which time no further accumulation of transition costs will be allowed unless derived from existing generation contracts and related ongoing contractual payments. With this exception, we will complete the collection of the CTC by 2005. The CTC will include regulatory assets, existing contractual obligations for generation, including Qualifying Facilities, and the undepreciated book value of a utility's generation plant as reflected in rate base as of this decision date. Our methods for valuing the CTC will rely to the extent possible on market mechanisms and will seek to minimize the burden of regulatory proceedings and the economic cost to California's economy.

California's commitment to public purpose and social aspects of the provision of energy services to all of our citizens has been marked by legislative, commission inspired, industry based and community prompted initiatives in the past and we fully anticipate such aspirations and effort to mark our state's future. In today's decision we set the stage for these developments by speaking directly to the fate of renewable resources, demand-side management, and public purpose research, development and demonstration efforts. Low income assistance, Women, Minority, and Disabled Veteran Business Enterprises, baseline rate, economic development programs, special rate discounts, low-emission vehicle and under grounding are all implicated in the reforms which are now launched, and today's discussion furnishes those constituencies with vitally affected interests with a more fulsome statement of our vision.

Throughout this proceeding we have acknowledge the applicability of the California Environmental Quality Act and the need for compliance once our deliberations had advanced to the stage that a project could be assessed. We believe that today's decision brings us to this critical juncture and so we define and discuss our compliance strategy.

Each of the general subjects covered by chapter heading in today's opinion is vital, and yet the focus of most debate and controversy has centered on the role of customer choice and the market mechanisms and institutions which must be developed to ensure an array of informed customer options. It is thus to these allied topics that we turn briefly in summarizing our actions of today.

B. Customer Choice and Consumer Protection

In the absence of well understood and easily exercised consumer options the genius of competition is thwarted. We began this Rulemaking and Investigation by declaring our single minded dedication to discovering and deploying strategies and mechanisms which would place sustainable, downward pressure on the cost of electricity to all classes of California ratepayers. From the beginning, our policy preference has inclined strongly in the direction of competition and market mechanisms. As we move from the realm of theoretical discussion toward deployment, our task is to ensure that the competition is genuine and market mechanisms are open to competitive entrants and transparent to those who must depend upon their function. With today's decision we believe that we have opened the door to the broadest possible array of choice in which the former "ratepayer" can function as an intelligent, self-interested "customer." We will briefly summarize those choices before detailing the market structure which will support their availability.

Customers for electric services in California reflect the diversity of our economy and society. They range from large industrial and commercial users to the smallest householder. They include agricultural users of every variety of description and husbandry. These differences in circumstances produce radically different load profiles and usage patterns. What we have termed as an "electric services industry" includes a basic commodity—electric energy—as well as a host of services in their generation, transmission and distribution.[2] Over time Californians have achieved world class leadership in the development of conservation strategies aimed at cost containment as well as environmental concerns. But there has been one aspect of the industry in which we have conspicuously failed to maintain a competitive presence and that is in the cost of electric energy. Our debates have revealed the broadest consensus that our rates are too high and must be brought into alignment with regional averages if California is to sustain a competitive posture as we enter the twenty-first century. Equally strong is the consensus that if market mechanisms can be developed that send strong, sustained and easily comprehended price signals both new market entrants and consumers will react with intelligent choices.

If our vision of the near term reform is realized, shortly after the first of January, 1998, customers in California will face an impressive array of choice. Ranged along a continuum of the degree to which the customer desires to become proactive in taking charge of cost containment, the essential choices will be made from three broad categories.

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[2] Throughout our discussion a convention has arisen in which references are made to "electrons" or "electricity" as the commodity that it generated, transmitted, distributed and consumed. Those who are concerned that we acknowledge the basic teachings of physics or electrical engineering will point out that the electrons oscillate and it is power that moves and is consumed.

1. Retain the traditional relationship as a full service customer of the local electric utility:

A customer of any class is free to elect continued reliance upon the local distribution utility to procure as well as deliver electrons. Yet even here there is choice as to how the customer's bill will be calculated. Those who prefer to retain an exact replica of the status quo can opt to have their volume of usage multiplied by a rate which reflects the average cost to the distribution utility of procuring the electric power. Customers who are willing to shift load in response to hourly or half-hourly price signals can elect what we have termed "virtual direct access", a rate structure which takes into account not only their volume but also the time of their usage.

2. Financial hedges:

Many customers may be disinterested in the choice of generation but desire price stability and predictability over a defined period of time. Such customers are free to elect hedging contracts which may be concluded with any individual or entity willing to take the counter-part risk. A customer who has formed such a contract continues to receive a bill from the local utility which reflects both the cost of electric power and distribution services. Periodically such a customer totals the amount of these payments to the local utility and determines whether they exceed the price guarantee concluded in the hedging agreement. In that event a bill is submitted to the other party who reimburses the customer so as to bring the cost of electricity for the period to within the agreed maximum. In the event that excess outlays have not been experienced the party who sold the guarantee keeps the premium for taking a risk that was never realized.

In our view parties agree to accept the risk in a hedging contract may have generation facilities or contracted rights to generation but we see no need to restrict their qualification or to in any manner make hedging contracts, termed "contracts for differences" in much of the literature, the object of Commission concern. Both entry into and exit from such a business, as well as the terms of such contracts are left to the genius of the marketplace and the will of market participants.

3. Direct access through physical, bilateral contracts:

With today's decision we propose to advance the availability of a direct access customer option even as we seek to clarify its consequences. While some have contended that, in the final analysis, such contracts represent but a variant upon the purely financial transaction, this view is disputed by those who see in them a genuine advantage and a distinct choice. We need not settle this debate for, in the final analysis, the decision will take place in the marketplace. In one clear respect this option differs from the hedging arrangement described in the second set of choices. In a direct access contract the parties seek to dispatch specific generation on the part of sellers as well as provide fixed financial terms to the consumer of electricity. To the extent that the dispatch matches a correlative customer load, the net impact of such contracts is to reduce the amount of electricity which will be procured on the spot market which will serve the needs of those customers who elect from the first and second categories.

Our evolved willingness to begin a phased availability of direct access contract options simultaneously with the introduction of the wholesale spot market stems from a hard won understanding of their true nature. A customer who forms a physical, bilateral contract directly with a generator, or an aggregator who will then delegate the task of generation to those actually in that business, forms a contractual arrangement which will influence the dispatch of generation and govern the financial consequences of consumption. However, save for those extraordinary circumstances in which the contracting parties bear the economic and societal costs of constructing a discrete, private means of transmitting the electricity from the contracting generator to the contracting customer, the bilateral contract does not control the actual physics of the generation, transmission and distribution of the electricity the buyer consumes. Such a customer will take physical service from the local utility which will deliver power commingled from an undifferentiated array of generators who are making common, simultaneous use of the transmission grid and distribution facilities.

The financial consequences of direct access contracts involve, at a minimum, four interests, three of which are readily identifiable: those of the customer who consumed a quantity of electricity, those of the generator who simultaneously supplied to the transmission grid a correlative quantity of electricity, and the local utility which delivered an equivalent amount to the customer's physical premises.[3] So long as the expectation interests of both parties to the bilateral contract are realized, and a settlement is made with the utility for all costs incurred other than that associated with the generation of the electrons, we see no need for the Commission to take a proactive role in defining these settlement arrangements.

C. Market Structure

The variety of customer choice which we seek for Californians after January 1, 1998, is currently unavailable any where in the world. To attain it will require the efforts of virtually every present and aspirant industry statekholder, our staff, and the members and staff of the Federal Energy Regulatory Commission. Much of the common labor will be directed toward framing the structure, fixing the rights and duties, and the deployment of two critical institutions: the Independent System Operator (ISO) and the Power Exchange (Exchange).

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[3] The Independent System Operator is a fourth party with a financial stake in the bilateral transaction. As is the case with generation nomination from the spot market, a dispatch nomination originating from a bilateral contract must obtain transmission services and thereby incur a liability for these service costs. Transmission liabilities must be settled with the operator of the transmission grid irrespective of their origin. In the case of nominations from the spot market settlement will be made by the utilities which then distribute the electricity to their customers. Bilateral contract nominations may be settled by the generator, the end use customer, the broker or aggregator, or the distribution utility acting as an agent for any of the parties. Again, we note the obligation to be resolved without the felt need that the Commission dictate the resolution. By the same token we leave the issue of compensating the broker for aggregator to the contracting parties who have elected to utilize such an intermediary.

1. The creation of two distinct entities to handle transmission and the spot market represents a change from the positions set forth on May 24:

We affirm a key policy decision and announce an amended position on a critical implementation strategy. In the statement of proposed policy preferences the majority declared its conviction that the vertically integrated electric utility is not compatible with the institutions of a competitive market for electric services. Today we are even more firmly convinced with respect to this belief. We also affirm our conviction that the interests of all Californians requires the creation of a transparent, visible spot market for electric generation and that operating control over all transmission assets be divorced from the underlying pattern of ownership and vested in the hands of an independent system operator which will operate these combined assets as a single, state-wide grid. However, unlike the majority's proposed policy preferences of May 24, we are now persuaded to vest the spot market pool and transmission grid operations in two distinct entities. We also adopt the suggestion that the spot market pool be termed the "Power Exchange" and that we refer to the operator of the transmission grid as the "Independent System Operator." The basic structure and function of these two entities and their critical inter-relationship are defined in this opinion. They may be briefly outlined.

2. The Power Exchange:

The Power Exchange will foster and sustain the development of a transparent spot market for the generation of electricity. Under the terms of the policy decision we announce today, the Exchange will have no financial interest in any source of generation nor will it have any ownership ties to the Independent System Operator. It will determine on a forecast basis the needs of those California customers with loads that are not being met by generators under the terms of direct access contracts. As a market institution it will function as a clearinghouse by providing a transparent auction for generation with hourly or half-hourly price signals evident to immediate users and long-term investors. We anticipate that the performance of this function will provide critical assurances to generators, wholesale buyers, and consumers.

a. The Exchange will facilitate open competition among generators:

The integrity of competition at the wholesale level will depend upon the formulation and continuous deployment of nondiscriminatory rules which permit rival generators to compete on common grounds using transparent rules for bidding into the Exchange. Generation units outside of California, including those operated by municipal utilities or public power entities, will be welcome to bid into the Exchange. Over time the ability to observe the price information will send the most reliable signals respecting the need for additional generation as well as cost-cutting steps required to keep existing units competitive.

b. The Exchange will provide invaluable services to consumers, including those who elect to contract directly for generation dispatch:

From the perspective of both wholesale and retail customers the most critical contribution of the Exchange lies in the auction determination of real time pricing of electricity and the transparent manifestation of these price signals. In the absence of such an institution the market will be hidden and the price signals obscured or subject to selective, discriminatory dissemination. If the California economy is to realize the efficiency gains brought about by competition among generators, the impact of that competition on the price of electricity must gain the broadest customer awareness.

Compared to the present practice of receiving and paying a totally unexplained utility bill, those customers who elect to remain with their local utility for purposes of generation procurement and distribution services gain the most startling advantage. They will be direct beneficiaries of the wholesale competition among generators in that the local utility will simply pass through to its customers the prices which it has paid to procure power through the Exchange. Customers who have chosen to have their bills computed on the average cost of power times consumption receive the benefit of the average pool price. Those who are willing to consider shifting load in response to the hourly or half-hourly price signals will have a rationale basis for electing the virtual direct access billing option.

Revelation of pool prices is also the key to the intelligent use of hedging or contracts for differences. The market for such contracts will be premised on the revelation over time of the spot price for electricity. Only by assessing the risk of spot market volatility can a consumer make a rationale decision that the vagaries of the pool price warrant the formation of a contract with a counterpart party who will guarantee a price over an agreed span of time.

We anticipate that the maturing market for energy conservation will also benefit from the price revelation of the avoided cost of energy.

By the same token, knowledge of the cost of receiving energy from the spot market will provide both end users and generators will the information from which they can calculate the relative advantages of forming physical, direct access contracts.

3. The Independent System Operator (ISO):

Reform of California's electric services industry begins with the creation of the Exchange and transparent spot market for generation. The creation of an Independent System Operator provides the essential entity to coordinate the daily scheduling and dispatch activities of all market participants as required to meet the critical objectives of providing open, nondiscriminatory access to the transmission grid while preserving reliability and achieving the lowest total cost for all uses of the transmission system.

The unavoidable interactions in the transmission network require the services of a system operator to coordinate the actual use of the system and apply a pricing structure that supports competition and avoids cost shifting. The central importance of these functions demands the confidence of all participants that the system operator is truly independent and that the protocols for pricing and operations are both economically efficient and compatible with the competitive market. We have described in some detail the minimum requirements to make fully clear our intent that these prices and procedures will be fair and economically efficient.

The ISO will take no position in the market nor have any economic interest in any load or generation. Its coordination functions will be limited to the short term, including the facilitation of day-ahead scheduling and hourly redispatch in order to balance the system and respect transmission constraints. Of necessity, the independent system operator must have the final responsibility for redispatch of the system needed to integrate the nominations from the Power Exchange and from direct access transactions. In executing these limited but fundamentally important responsibilities, we are dedicated to the view that the ISO must be indifferent to the status of generation or load as from the Exchange or from a bilateral transaction. Furthermore, the ISO must determine the rational economic prices to apply to all uses of the transmission grid to ensure that the associated incentives are consistent with the competitive market and least cost use of the transmission system. We have specified the elements of such an efficient pricing system that ensures that charges for transmission use avoid any bias for or against participation in bilateral transactions or in the Exchange. The essence of this pricing system stands on the well established foundation of the competitive market principles of marginal cost pricing. The ISO will determine the marginal cost prices, differentiated by location and time, that will apply to all uses of the transmission system. These locational, hourly prices will apply to purchases and sales through the Exchange and the equivalent differences in prices between locations will apply as the transmission prices for bilateral transmission. The implementation of this efficient, nondiscriminatory pricing system could be achieved simply through a so-called "hub and spoke" system that would organize transmission grid usage around a number of regional hubs that will be the focus of commercial transactions. We invite the suggestion of alternative strategies that achieve these policy objectives.

Many market participants have a legitimate need to achieve some certainty about their future costs for transmission use, in order to arrange for long-term power transactions. Ideally, a system of physical property rights defining use of the transmission grid would exist and be able to support our objectives for a competitive market. However, the same conditions which require the coordination role of the ISO preclude any practical system of independent physical property rights which could govern use of the transmission grid. The alternative is to create a system of contracts that provide the equivalent certainty for long-term transmission costs without compromising short-term operations coordinated through the ISO. Therefore, in addition to coordinating the daily and hourly dispatch, the ISO will administer a system of transmission congestion contracts. We believe this system of tradeable contracts provides the best method of meeting the legitimate needs of the market while respecting the special conditions of the interconnected transmission grid.

We recognize fully that these various functions of the ISO constitute an important innovation that, while fully consistent, goes well beyond the minimum requirements currently being considered in proposed rulemakings at the Federal Energy Regulatory Commission. We have adopted this consistent set of proposals based on the comments of many parties and a careful study of the relevant features of other reforms in transmission systems elsewhere in the United States and in other countries. We are confident that California can capture and improve upon the best practice, and that Californians are fully capable of implementing here incremental improvements on what has been embraced elsewhere. Hence we direct the participating utilities to formulate a detailed proposal that adheres to the minimum requirements we have specified and to present such a proposal to FERC for its approval. We are confident that this system will meet and advance well beyond the FERC minimum standards by providing a package which is both a "conforming, open access" and an "innovative pricing" proposal.

II. PROCEDURAL HISTORY

In April 1992, we initiated a comprehensive review of current and future trends in the electric industry. This process produced a Rulemaking proceeding on restructuring California's electric services industry and reforming regulation, which was issued on April 20, 1994. The Rulemaking envisioned a future in which customers would have choice among competing generation providers, and in which traditional cost-of-service regulation would be replaced by performance-based regulation. We issued the Rulemaking for extensive public comment and solicited comprehensive alternatives to the vision described in that document.

Since April, we have sat together in San Francisco, Sacramento, San Diego, and Los Angeles for six days of public hearings on industry restructuring and regulatory reform. Over 140 individuals and organizations have presented comments on the Commission's Rulemaking, either in written form or as oral testimony at these full panel hearings.[4] (See Appendix C.) In addition, thousands of California citizens have voiced their opinions on industry restructuring, many of them at the 16 public participation hearings attended by the Commissioners and held throughout the state: Eureka, San Diego, South Lake Tahoe, Stockton, San Francisco, Martinez, San Jose, Fresno, Pasadena, Bakersfield, Ventura, Garden Grove, Carson, San Bernardino, and Huntington Park. Many more have participated via Internet with written comments, submitted videos, or watched the full panel hearings on public broadcasts over CAL-SPAN.

We also conducted a week of evidentiary hearings on issues related to uneconomic assets. In addition, we have engaged our western North America counterparts, federal agencies, and legislators in constructive dialogues on cooperative solutions to jurisdictional issues. On December 7, 1994, we invited a working group, comprised of interested parties, to prepare a written report on sustainability of public purpose programs and options for attaining our

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[4] Such public, recorded meetings where all Commissioners are present are generally called "full panel hearings." They are conducted in a legislative style.

objective in a variety of restructured market models. On January 31, 1995, numerous parties filed briefs on legal issues. Appendix B presents a procedural history of our proceeding on electric industry restructuring and regulatory reform.

On May 24, 1995, we issued our majority and minority policy preference statements. For those unfamiliar with those documents, their essence was captured in our preface to the majority's proposed policy decision:

> We commenced this Rulemaking because of our unanimous belief that as the electric services industry moves toward embracing competition, command and control regulation is no longer an appropriate mechanism. We have concluded that two of the major proposals offered to the Commission, generally referred to as the "PoolCo model" and the "Direct Access Model", reveal few true conceptual differences. Both proposals share a foundational premise of encouraging competition to flourish in the production of power. Mirrored in both is the proposed application of performance based ratemaking techniques where competition is absent. Both proposals also recognize the need for an entity independent of generation ownership charged with transmitting power. Furthermore, both plans recognize and address critical issues related to market power, jurisdictional ambiguity, transition costs and consumer choice. The significant difference between [the pool based and contract predicated models] lies with the manner in which the economic dispatch of power would be achieved.

The essential similarity as well as the difference between the two models found reflection in the Commission majority's vision of preferred market structures as well as the preferences of the minority. The majority proposed creating an independent system operator which would perform two critical functions: it would dispatch generation predicated on an open bidding mechanism to meet day ahead forecasts for California's electricity needs, and it would arrange transmission access for those generators with bids that cleared the pool price. The majority envisioned two distinct roles for private contracts. Financial instruments of any nature designed to hedge the pool price were deemed outside the realm of governmental regulation and immediately available to customers and other market factors who wished to contract for price stability on any terms congenial to the parties. Physical, bilateral contracts between a customer and a generator were also envisioned, but in the majority's preference their introduction would occur two years after the pool had been established and the characteristics of the wholesale market had become familiar to customers.[5] The minority differed from the majority in asserting the view that the establishment of a wholesale pool should not be a precondition to the availability of a market structure predicated on physical, bilateral contracts. While acknowledging the indispensable role of an independent system operator, a preference was expressed for a role which did not include the dispatch of generation save in those circumstances in which it was necessary to achieve system balance or preserve system stability. The minority also expressed doubt as to the need for a single operator and held forth the vision of multiple, competing operators of the transmission grid.

By unanimous vote the four sitting Commissioners issued both policy proposals for comment with the explicit request that stakeholders express their views on both our selection of goals as well as articulated means to achieve those goals. "Equally important is the sincerity of our invitation that we are open to the suggestion of alternate goals or alternative means to pursue the goals which we have advanced." The response from stakeholders has been both gratifying and constructive. In addition to both written and oral contributions to our hearings, participants have arrayed themselves in a variety of discussion groups seeking to evolve common understandings and positions. Two of these efforts merit special mention. In September we received a Memorandum of Understanding which conveyed the joint recommendations of four of the major participants in our proceedings.[6] While it covered numerous points, its basic focus was

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[5] The majority also expressed concern that both transmission and jurisdictional impediments to the implementation of what has been widely termed "retail wheeling" or "direct access" be resolved during this two year period. The singular policy goal was that any costs and benefits from such bilateral arrangements be born and enjoyed by the direct participants and not imposed on other users of common transmission and distribution facilities.

[6] The Memorandum of Understanding or MOU was submitted by of Southern California Edison (SCE), the California Manufacturers Association (CMA), the California Large Energy

on issues of market structure and stranded asset and liability issues. In early October we were favored with a joint submission of eleven public interest, environmental, alternative energy, and consumer advocacy organizations. Termed a "Framework for Restructuring in the Public Interest," it elaborated on public interest and customer oriented principles.[7] The recommendations in these submissions, as well as from other sources, are acknowledged and examined in the course of today's decision. Their influence has been substantial and is repeatedly acknowledged. While some have elected to look askance at these efforts we are not to be included in their number. We regard these submissions as compliant with both the letter and spirit of our invitation of May 24. Common to both recommendations was the open acknowledgment that the task of divining the public interest and selecting policy choices to defend and advance that interest is ours. Therefore unless we are instructed otherwise by legislation or discover unanticipated and serious impediments in the course of our implementation effort, today's decision may be looked to as the foundation for California's emerging market institutions and regulatory reforms.

Consumers Association (CLECA), and the Independent Energy Producers (IEP).

[7] Framework sponsors included the Utilities Consumer Action Network (UCAN), Union of Concerned Scientists, Toward Utility Rate Normalization (TURN), Sierra Club of California, Natural Resources Defense Council (NRDC), Environmental Defense Fund (EDF), Center for Energy Efficiency and Renewable Technologies (CEERT), California Public Interest Group, California/Nevada Community Action, and the American Wind Energy Association.

III. MARKET STRUCTURE

Introduction

With today's decision we launch California's bid for a market structure that embraces competition in the provision of electric services, offers retail customers choice and flexibility in energy services, and reforms the manner in which we regulate utility monopoly services. Critical to this new market structure is the establishment of a statewide Independent System Operator (ISO) responsible for coordinating the dispatch and delivery of power over the transmission system. In addition, the creation of a regional Power Exchange, charged with the purpose of developing a visible spot market with transparent prices for electricity and open to all suppliers, including out-of-state suppliers and municipal utilities, will enhance efficiencies by introducing competitive pressures into the generation sector. The Power Exchange and the ISO would be two independent and separate entities, the design and operation of which will require approval by FERC.

No later than January 1, 1998, simultaneous with the establishment of the Power Exchange and the ISO, we will advance the opportunities for customer choice in electric services by implementing several options for customer participation in the market. With direct access, customers can choose to purchase power according to default rates or through negotiated terms and conditions directly with competing nonutility generators, or less directly through brokers and marketers. We fully expect that all customers will have the opportunity to enjoy these forms of customer choice no later than five years from the start of our new market structure. Utilities will continue to procure power for those customers who choose not to arrange retail contacts with suppliers and will continue to provide nondiscriminatory distribution services to all customers within their service territories. These procurement and distribution functions of the utilities will remain under our regulation and be subject to incentive regulation.

Our decision today advances federal and state goals of increasing competition in generation and providing open, nondiscriminatory transmission access and service. At the outset, we recognize that establishing a new market structure for electricity in California will require close cooperation and coordination with the Federal Energy Regulatory Commission. The creation of the ISO and the Power Exchange requires exercise of jurisdiction by both this Commission and the FERC under a policy of cooperative federalism. This shared jurisdiction raises the possibility that disgruntled parties may attempt to delay or overturn our decision by claiming that our authority to act is preempted by federal law. Such tactics would be disruptive of reforms which command the broadest support on the record before us. As private decisions they cannot be precluded, nevertheless it is our intention to minimize any provocation by the steps we take today. We begin by acknowledging that the boundaries of federal and state jurisdiction begin to blur in the context of new market structures. Our policy of cooperative federalism embraces our counterparts at the federal level as well as other western jurisdictions. It also manifestly includes market participants who must, in the finally analysis, cooperate actively if a shared vision of a more competitive and productive electric services industry is to be realized. In furtherance of these objectives we now begin a statement of our policy preferences respecting the formation and function of the critical market institutions. We suggest ways of furthering these policies in the context of industry initiatives as well as filings here and at the FERC. Finally, in areas committed to shared jurisdiction or conceded to be within the domain of federal authority, we suggest mechanisms and protocols which would advance the preferences we have identified as in California's interest. Our intention is not to forestall other suggestions or means to achieve these ends, but to demonstrate plausible strategies which have convinced us that our goals are attainable.

We acknowledge that by choosing to cooperate in the development of new market structures, the three major utilities subject to our regulation have removed much of the jurisdictional uncertainty associated with electric restructuring. These utilities have voluntarily agreed to support a consensus model based on transferring control over the transmission system and dispatch operations to the ISO, participating in a Power Exchange, and providing their retail customers with direct access to alternate suppliers. Without this cooperation, it is unlikely that new market structures could be implemented in California in the time frame we propose today.

Even with this level of cooperation, the implementation of the ISO, the Power Exchange, and retail competition raises questions of where jurisdiction lies over cost recovery and regulation of transmission service and sales of power. We suggest ways to coordinate with the FERC on these issues in our discussion of market structure.

We describe this new market structure in the following sections. In Section III.A, we discuss the disaggregation of the utilities' transmission function and the transfer of that function to an ISO, how the ISO is to be established, its critical scheduling and balancing responsibilities, safety and reliability issues, and the financial settlement process. In Section III.B, we describe the Power Exchange which we believe will enhance efficiencies. In Section III.C, we discuss the ownership and structure of the ISO and Power Exchange. Section III.D describes the opportunities for customer choice in electric services. We then turn to Section III.E, where we discuss our continued regulation of the utilities and how Performance Based Ratemaking fits into this process.

A. Disaggregation of the Utilities' Transmission Function and the Establishment of an Independent System Operator

The electric grid is an interconnected system of transmission, distribution and other related facilities. Operation of the electric grid requires that variations in generation supply and demand levels are continuously balanced. Currently, the responsibility for system operation resides with the vertically integrated utilities which also own and control a majority of generation assets and nearly all of the distribution assets serving the California market.

Our May proposals concluded that, at a minimum, it was necessary to disaggregate the vertically integrated electric utility by separating the elements of generation, transmission and distribution. Focusing on market power concerns that arise from the utilities' ownership and control over transmission facilities, we proposed that the utilities transfer the operational control of all transmission facilities to an ISO. Today we affirm this proposal. The establishment of an ISO lessens the potential for owners of the transmission system to favor their own generation facilities over nonutility facilities in providing transmission access. Coupled with FERC's principles of open, nondiscriminatory transmission access, disaggregation of the transmission function will enhance fair competition among generators.

The establishment of the ISO will confer four immediate and lasting advantages upon all users of electricity in California.

1. The state will achieve a permanent and functional resolution of transmission access disputes between the transmission-owning utilities and those dependent upon access to the system.

2. There will be a lasting efficiency gain resulting in cost savings due to combining the now distinct control functions of many entities under the auspices of a statewide independent system operator.

3. There will be an operational efficiency inherent in a transmission network which has no economic interest other than fostering open access and the facilitation of supply from generators irrespective of their ownership.

4. There will be a consistent pricing system for the use of the common network facilities that prevents cost shifting and supports the competitive market.

1. The ISO is Separate from the Power Exchange

The May pool proposal conceived that in addition to coordinating the transmission system, the ISO would have a second function: making a transparent market for generation with price signals evident to immediate users and long-term investors. The MOU built on the May pool proposal's concept of the ISO by suggesting one significant change: the separation of the ISO from the spot market pool functions, which the MOU assigned to an entity called the Power Exchange.

Parties favoring separation advance two primary reasons to separate the ISO from the pool. First, separation would prevent the ISO from favoring pool transactions over transactions occurring outside the pool or from unfairly restricting the operation of nonpool suppliers in case of grid congestion. Second, separation would provide an opportunity for developing transparent information about system operations and congestion which would aid in eliminating any perception of discriminatory decision making. Parties preferring establishment of a single entity with the responsibilities of an ISO and a power pool assert that the coordination between two separated entities could be complicated. They also argue that the separation would interfere with economic dispatch of generation and would create additional transaction costs.

Because the new market framework must at its conception have the support and confidence of market participants, and because the separate entities will function similarly to and bring the same benefits as a structure which combines the two, we are convinced that these potential problems are best resolved by requiring that the functions of the ISO and the pool be vested in separate entities. The independence of the ISO from the pool reinforces the principle that all market participants are subject to the same protocols regarding allocation and pricing of transmission access along with resolution and pricing of transmission congestion. This separation should eliminate any perception that the ISO could gain financially by preferring one supplier over another in dispatching generation and scheduling transmission.

2. Principles for Operation of the ISO

Under the Federal Power Act the FERC has authority over rates, terms, and conditions of sales for resale and transmission in interstate commerce. Courts have determined that the transmission of electricity, even between two points within a state, making use of interconnected interstate grids falls within the federal interest in interstate commerce. Thus, the FERC must approve rates, terms and conditions of transmission services provided by the ISO. We expect that the ISO will file its own transmission tariff and operating procedures with the FERC. Under state law we must approve transfer of control over the investor-owned utilities' transmission systems and dispatch facilities to the ISO. Following the FERC's approval of the ISO, utilities will need to file for our approval under Public Utilities Code § 851[8] to transfer control of their transmission facilities to the ISO.

We authorize PG&E, SCE and SDG&E to work with parties and each other to develop a detailed proposal for submission to the FERC to establish the ISO and its protocols and transfer operational control of the utilities' transmission facilities to the ISO. We fully recognize that these proposals go beyond the minimum requirements specified by FERC and include new, innovative transmission access and pricing approaches. However, we believe that these proposals will amply meet the test of being a conforming, open access system that improves over the minimum requirements in the directions recommended by FERC and necessary for the competitive market. These proposals shall be filed at FERC and simultaneously filed in this docket within 130 days after the effective date of this decision. The filing should incorporate the principles delineated below, which we believe are critical to the successful operation of the ISO.

1. The ISO will have primary responsibility for the determination of the final operation and dispatch of the system to preserve reliability and achieve the lowest total cost for all uses of the transmission system. The ISO will have control over the operation of the transmission facilities. The participating investor and publicly owned utilities will continue to own those facilities and be responsible for their maintenance.

2. The ISO will have no financial interest in the Power Exchange or in any source of generation or load. This restriction will ensure that the ISO will have no bias in favor of or against generators who participate in the pool or as suppliers with direct access contracts. The ISO will own no generation, transmission, or distribution facilities and will have no affiliation with any companies that own those facilities.

[8] Unless otherwise indicated, all statutory references in this decision are to the Public Utilities Code.

3. The ISO will maintain frequency control and comply with all standards of the North American Electric Reliability Council (NERC) and the Western Systems Coordinating Council (WSCC).

4. The ISO will provide open and nondiscriminatory services and access to the transmission grid for all users of the transmission system, including purchasers and suppliers in transactions arranged through the Power Exchange and suppliers contracting directly with customers, consistent with the principles espoused by FERC in its proposed rulemaking on open access transmission services and stranded costs.[9] All market participants will be subject to the same protocols and prices regarding transmission access and treatment of transmission congestion.

5. The ISO will procure from suppliers ancillary services needed to support transmission and dispatch. Where possible, this procurement should be from suppliers on a non-discriminatory, competitive, unbundled basis. The ISO will offer to users ancillary services either as competitive, unbundled activities, for those services that can be metered and measured separately for individual users, or as cost-effective joint products, for those inherently inseparable network services.[10]

6. The ISO will coordinate day-ahead scheduling and balancing for all uses of the transmission grid. For both the day-ahead schedules and the hourly balancing transactions, the ISO will accept nominations from the market participants. The nominations from the Power Exchange will include the tentative dispatch, the locations of the generation and loads, and the associated bids for generation and loads. The nominations from the bilateral participants must include the amount

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[9] Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities (Docket No. RM95-8-000); Recovery of Stranded Costs by Public Utilities and Transmitting Utilities (Docket No. RM94-7-001), 60 Fed.Reg. 17662 (April 7, 1995) IV FERC Stats & Regs ¶ 32, 514 (1995) [hereinafter referred to as the "MegaNOPR"].

[10] The distinction between procurement and provision is critical in identifying what can be unbundled and treated as a competitive service left to individual choice. For example, spinning reserve can be purchased from many sources on a competitive basis, but it may not be possible to separately identify the individual customer uses of spinning reserve. In this case the ISO would pay suppliers the competitive price for spinning reserve and charge all users an allocated share of the total cost of spinning reserve.

and timing of power deliveries, along with the source and destination for power transmission. In addition, the ISO will accept from the bilateral participants bids for increments and decrements of nominated inputs or outputs that would be available from the bilateral transaction as needed to redispatch the system. The Power Exchange supplies classified as must take will use the same ISO protocols.[11]

7. The ISO will coordinate the scheduled nominations from the Power Exchange and the bilateral transactions to determine any redispatch that would be necessary to meet the twin objectives of assuring operational reliability and achieving least-cost use of the system. Along with this redispatch, the ISO will determine the locational marginal costs incorporating the cost of generation, losses and congestion that will define the market clearing prices for the Power Exchange and the price of transmission use for the bilateral transactions. The marginal costs of redispatching to provide an increment of load at each location will define the purchase and sale prices through the Power Exchange. The differences in the locational marginal costs between source and destination will define the price of transmission applied to the bilateral transactions. The ISO will notify the Power Exchange and the bilateral participants of the final redispatch for the scheduled nominations and the associated prices that will be charged for transactions.[12]

8. The ISO will coordinate the implementation of the final schedules to adjust as necessary to ensure the reliability and least cost for the actual hourly dispatch. Again, the ISO will accept supply and demand bids from the Power Exchange and increment or decrement bids from the bilateral participants for their transactions. Over the course of the day, the ISO will order any redispatch adjustments as necessary to balance the system. Associated with this actual dispatch, the ISO will again compute locational marginal costs. These actual dispatch locational

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[11] Must take supplies include all grand fathered generation contracts, including QF's, and nuclear facilities.

[12] Implementation of this locational pricing mechanism could embrace a simple "hub-and-spoke" system. The ISO would identify a number of critical locations to serve as system hubs that would be the focal points for pricing and transmission information. All users would incur the necessary transmission charge to move power to or from their nearest hub. Movements of power over longer distances would be on the basis of the differences in the locational prices at the respective hubs.

marginal costs will define the locational prices to apply to any imbalances relative to the scheduled generation and loads. With this pricing, there will be no need for any other limitations or penalties for any participants for load or generation in the actual dispatch.

9. The revenue collected for transmission use from direct access participants and the Power Exchange will include payments of congestion costs arising from the redispatch of the system in the face of transmission constraints. The ISO will administer a system of transmission congestion contracts to redistribute the congestion payments and provide a set of tradeable instruments to support long-term commercial transactions across locations in the grid.

10. The ISO will provide a system of open communication of information for the scheduling market. Individual bids and nominations will be confidential, but all other reasonable information on market clearing prices, power flows, the state of the transmission system will be made available to all participants in an appropriate, timely, and non-discriminatory manner. The ISO will also provide information necessary for long-term studies by market participants to support commercial contracting and investment decisions.

3. The ISO's Coordination Responsibilities

a. Scheduling:

On a day-ahead basis, the ISO will schedule the dispatch and delivery of electricity according to suppliers' preferred schedules, which reflect the terms and conditions of bilateral contracts, existing utility contracts with nonutility generators, and transactions mediated through the Power Exchange.

The ISO will have no direct responsibility for dealing either with so-called "must take" units or any generation obligations under existing contracts. These obligations will remain with the contracting parties, including the utilities and any other producers. These parties will have the opportunity and the responsibility to nominate the necessary generation or load either as bilateral transactions or through the Power Exchange with the allowable degree of flexibility for redispatch. Any costs incurred through purchase and sale in the Power Exchange or as a transmission usage charge for a bilateral transaction will remain the responsibility of the contracting parties.

b. Managing Transmission Constraints and Congestion:

In California there exist transmission bottlenecks or constraints that may affect the choice of which generators will actually be dispatched. Effective management of transmission congestion is critical. We note the concern expressed by Professor Paul Joskow with regard to the ISO prioritizing the scheduling of direct access supplies and Power Exchange supplies:

> If Power Exchange transactions are not treated *identically* to "bilateral schedules" for the purposes of allocating scarce transmission capacity and in responding to other network contingencies that require out-of-merit order operations, significant distortions and inequities *might* result. I am especially concerned that "bilateral schedules" will endeavor to be defined as having first priority for "firm" transmission capacity, while Power Exchange transactions are treated as being "non-firm" residuals. Combined with direct access this could advantage large customers who get direct access first and disadvantage small customers who get it later. It could also disadvantage generators that are committed to sell through the Power Exchange and, eventually, would undermine the Power Exchange as a robust spot market with visible prices and reduce it to a residual energy regulation market.[13]

We agree that such a scheduling order could place Power Exchange suppliers at a disadvantage. Such a result would violate the cardinal principle that the ISO should resolve transmission congestion and achieve a least-cost dispatch with total indifference as to the source of generation affected by the constraint.

Pricing actual transmission usage at the difference in the locational marginal costs determines fair and efficient use of available transmission without cost shifting. This efficient transmission pricing also sends the correct signals for needed investment in upgrades to the transmission system. We favor more market-driven mechanisms supported by the open,

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[13] Paul Joskow comments filed on October 23, 1995 to the Coordinating Commissioner's Ruling issued October 12, 1995. (Emphasis in original.)

comparable and nondiscriminatory principles promulgated by FERC, rather than regulatory or administrative approaches.

Transmission congestion contracts for compensation for congestion costs between locations offers a mechanism for providing long-term stability in transmission costs for those market participants who invest in transmission.[14] The fixed charges of the existing transmission grid could be recovered through a system of access charges. In principle, these access charges would be equivalent for each utility, at least initially, to the current payments for transmission assets that are in the rate base. A set of feasible transmission congestion contracts for the existing system could be distributed through an auction mechanism which would be open to all market participants, with the auction revenues used to offset the fixed charges for the existing system. We direct the utilities to develop a mechanism for allocating both the fixed charges and allowable transmission congestion contracts for the existing system as well as for prospective investments in transmission upgrades.

c. Real-Time Load Balancing:

System imbalances resulting from differences between scheduled dispatch and actual dispatch must be managed by the ISO as part of its real-time dispatch function. The ISO should ensure that adequate generation capacity is available to maintain frequency and to manage generation and load fluctuations. It will be necessary for the ISO to have physical control of the operation of some generation facilities in order to balance the system and respond to unforeseen circumstances. The ISO must also have the ability to alter the order of dispatch when necessary to maintain system reliability and stability.

Customers will be responsible for the costs of system reliability and ancillary services incurred on their behalf. To the extent ancillary services can be separately identified and

[14] We have the advantage of this innovative approach to transmission through the comments of many parties. One description generally consistent with the approach we recommend can be found in the comments of SDG&E in the FERC Mega NOPR.

metered, the ISO should establish an unbundled list of services. Customers will have the choice of selecting services from that list (in which case the services will be procured by the ISO competitively and customers will be charged according to the ISO's tariffs) or procuring the services independently. For any ancillary services that cannot be separately identified and metered, the ISO will procure necessary services, and the costs should be paid by all users of the system.

d. Maintaining Reliability and Increasing Efficiency:

The ISO should evaluate the physical condition of the transmission grid and report on the ability to continue existing transmission congestion contracts or the opportunities for upgrades needed to maintain reliability or to increase efficiency. However, the principal impetus for transmission investments should come from market forces manifest in the requests from customers who are willing to pay for the upgrades in exchange for incremental transmission congestion contracts and protection from future system congestion costs. In the absence of willing customer requests, investments in the transmission grid should be made only in the case of a showing to the regulators that there has been a market failure leaving important modifications undone because of an inability of market participants to agree on a sharing of the costs and benefits. In the context of cooperative federalism, the regulators and appropriate authorities should maintain the prerogative to authorize the permitting and assign the costs of the investment and the benefits of incremental transmission congestion contracts among the various users of the system.

Since states will continue to be responsible for siting, recommendations for upgrades should be made to the Western Regional Transmission Association (WRTA), FERC, and the Commission. This process may be facilitated by establishment of a Joint Siting Board under Federal Power Act § 209.

In this context we reaffirm our full support of the concept and function of Regional Transmission Groups. We will continue to participate in the process associated with the formation and operation of such entities in efforts to ensure efficient investment in new transmission and related facilities.

e. Recovering the Cost of Providing Ancillary Services

In the market structure we adopt today, the suppliers and their intermediaries (including the utility in its procurement role) have the responsibility to match the dispatch of electricity supply with expected customer load according to the terms of their retail or wholesale contracts. The suppliers will schedule dispatch based on forecasted load on a day-ahead basis. On a daily basis, the ISO will coordinate these schedules and manage reserves and transmission congestion to ensure that actual load requirements are met. If actual load requirements do not match the forecasted requirements or, if a supplier fails to produce the scheduled generation, the ISO will balance the load using available supply options such as spinning reserve, or other competitive supplies, including any such services offered through the Power Exchange or from participants in bilateral transactions.

f. Information:

Transparent information flow is critical to ensuring equal access to transmission capacity. Users of the system should have access to information regarding system status, e.g., constraints, load distribution, line losses, and other related information that would be useful in operation of their facilities. The ISO should make system data available quickly and on a comparable basis to all market participants.

4. Jurisdictional Issues Related to the Creation of the ISO

Creating the ISO raises jurisdictional issues, including the questions of who has jurisdiction over unbundled retail transmission and where the line should be drawn between the transmission and distribution functions. In the original and supplemental Notices of Proposed

Rulemaking (NOPR) on Stranded Cost Recovery,[15] the FERC addressed these issues in the context of discussing its jurisdiction over the transmission component of an unbundled retail wheeling transaction. The FERC distinguished between transmission, which is subject to the FERC's exclusive jurisdiction (except that the FERC is prohibited from ordering retail wheeling) and local distribution, which the FERC found to be subject to exclusive state jurisdiction. The FERC asserted, based on its analysis of Supreme Court cases addressing the scope of transmission in interstate commerce, that all transmission, including the unbundled element of transmission in a retail wheeling transaction, is subject to its rate-setting jurisdiction.

In the Supplemental NOPR, the FERC proposed a functional test to find that all wholesale transmission is subject to exclusive federal jurisdiction, even if the transmission occurs over distribution lines. To determine where the line between transmission and distribution in an unbundled retail sale should be drawn, the draft proposed rulemaking rejected adoption of a "bright line" test, and instead opted for a functional/technical list of factors to be applied on a case-by-case basis. The FERC stated its belief that in most circumstances, some portion of the facilities used to transmit energy from the transmitting utility in closest proximity to the end-user (the former supplier of the bundled product) consists of local distribution facilities.

The FERC invited state commissions to request clarification concerning whether certain facilities are local distribution facilities. Here is our response. Based on the record in this combined proceeding we concur with the suggestion of the utilities that the FERC should rule that facilities transferred to the ISO are FERC-jurisdictional and that those retained by utilities "downstream" of the ISO are local distribution facilities, if used to make retail sales, whether to retained utility customers (bundled) or to direct access customers (unbundled). This test would

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[15] Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Notice of Proposed Rulemaking, 59 FR 35274 (July 11, 1994), IV FERC Stats. & Regs., Proposed Regulations ¶ 32,507.

work for defining jurisdiction in the context of the ISO as well as for the unbundled components of a direct access transaction. It is consistent with the FERC's reasoning in the Supplemental NOPR:

> In the case of a distribution-only utility, which is franchised by a State or local government and sells only at retail, all of the circuits (and related wires, transformers, towers, and rights of way) which it owns or operates (regardless of voltage) would be local distribution facilities.[16]

The assertion of federal authority over the rates, terms, and conditions of unbundled retail transmission has been challenged, and it is not clear how the FERC (or the courts) will ultimately rule. Whatever the eventual outcome, it is clear that under the new market structure proposed today, the FERC will be regulating a significantly larger portion of transmission revenues than it currently does. We recognize that establishing the ISO will require a fundamental shift in regulation of transmission assets. Currently, we allow utilities to recoup approximately 90% of costs of transmission assets through retail rates. Revenues from rates set by the FERC for wholesale transactions are treated as an offset to the utilities' revenue requirements. Under our proposal, many of these assets will be designated as wholesale since they will be used by the ISO in fulfilling its responsibilities. These assets may of necessity be removed from retail rate base with the corresponding charges reclassified as access charges for the distribution utility. In principle, there should be no difference in the transmission fixed costs charged ultimately to retail customers.

During the transition to the new market structure, we have a strong public interest in ensuring that rates charged for transmission services, which up to now have been subject to our rate-setting authority, continue to be just and reasonable. In particular, we are concerned that cost-shifting from over- or under-collection of revenue could result from dividing jurisdiction over transmission and distribution. We intend to safeguard against revenue over or under

[16] MegaNOPR at 285, n.395.

collections by participating in the proceedings instituted at FERC to establish the ISO and the Power Exchange.

As part of its review, the FERC will be asked to confirm a designation of certain facilities as local distribution facilities, both for rate purposes and for the purpose of recovering retail stranded costs. It is important that the FERC rule that every retail sale, regardless of whether to a direct access customer or utility service customer, contains a local distribution component to assist California's implementation of a non-bypassable basis for recovery of transition costs. This process will allow both state and federal regulators to review and approve rates while avoiding litigating the question of where transmission ends and distribution begins.

B. The Power Exchange Provides a Visible Market for Generation

The Power Exchange will function as a clearinghouse by providing a transparent market for generation with hourly or half-hourly price signals evident to immediate users and long-term investors. The performance of this function will provide critical information vital to informed market decisions by generators, wholesale buyers, and end-users.[17]

1. The Power Exchange will implement nondiscriminatory rules which will permit rival generators to compete on common grounds using transparent rules for bidding into the Exchange. Generation units outside of California, including those operated by municipal utilities or public power entities, will be welcome to bid into the Exchange. Over time the ability to observe the price information will send the most reliable signals with respect to the need for additional generation as well as cost-cutting steps required to keep existing units competitive.

[17] Vesting the Power Exchange with this function involves operation of the pooling mechanism and will require FERC approval. This being said, we see no impediment in federal law to a state commission order requiring investor-owned utilities to use the federally approved Power Exchange as a market mechanism to dispatch electricity generated from assets currently in retail ratebase and subject to the exclusive jurisdiction of the state. Such an order would be well within our authority over the retail electric utility franchise and state electric resource planning.

2. Wholesale and retail buyers will be able to make efficient purchasing decisions and to modify their electricity consumption in response to immediate price signals.

The market-clearing locational prices can also serve as benchmarks for risk allocation contracts to hedge against market uncertainty or secure long-term price stability. Trends in the market-clearing prices would allow investors to determine the cost-effectiveness of incremental supply and thus facilitate long-term investment decisions. Moreover, customers who are equipped with real-time or time-of-use meters will be able to use real-time pricing information provided by the Power Exchange to judge the attraction of a virtual direct access billing computation and adjust their consumption by shifting usage to off-peak periods of demand. The hourly or half-hourly market price will also be used to settle imbalances due to supply shortages or higher-than-expected demand.

1. Principles of the Power Exchange

We direct PG&E, SCE and SDG&E to work together and with California's municipal and publicly owned utilities and other parties to propose recommendations for the establishment and operation of the Power Exchange. These recommendations should follow the policy guidance we describe below and include proposals for ownership, structure, pricing mechanisms, bidding protocols, and communications with the ISO. The recommendations should be filed at FERC and in this docket within 130 days after the effective date of this decision.

The principles and characteristics of the Power Exchange are similar to those adopted for the ISO.

1. The Power Exchange will have no financial interest in any source of generation to ensure that it will have no bias in favor of or against specific generators. The Power Exchange will be prohibited from owning generation, transmission or distribution facilities and will have no affiliation with any companies that own those facilities.

2. The Power Exchange will have no financial interest in or relation to the ISO.

3. The Power Exchange will be allowed to recover those costs associated with implementing a bid process for generation and establishing a one-hour or half-hour market-clearing price.

4. The Power Exchange will oversee the ranking of least-cost generation facilities according to established protocols.

5. The Power Exchange will establish nondiscriminatory and transparent bidding protocols. These protocols will include provisions for unit commitment in the day-ahead schedule and the procedures for payment of any minimum load or start-up costs not covered through the market clearing prices for energy.

6. The Power Exchange should establish the appropriate computer links necessary for information exchange.

2. Responsibilities of the Power Exchange

The Power Exchange will conduct an auction in which generators will submit bids under transparent bidding procedures. These bids should state the minimum price for which suppliers are willing to dispatch a specified amount of power the next day in hourly or half-hourly time increments. The Power Exchange will then match the generators' bids with demand bids submitted by utilities, brokers, marketers or any authorized entity on behalf of end-use customers. As specified by the ISO, the Power Exchange next will determine and submit a contingent dispatch for generators. Using its established scheduling protocols, the ISO will then integrate the Power Exchange's preferred schedule with the schedule nominations arranged under direct access contracts and communicate system information affecting the submitted dispatch schedules. The Power Exchange will, in turn, notify generators of accepted or revised dispatch schedules.

The market-clearing locational prices will be obtained from the ISO (by a time certain) as part of the integration and coordination of the alternative nominations and bids. Every winning generation bidder will be paid the market-clearing price at its location, which price is consistent with both the bid and the supply and demand equilibrium.[18] The Power Exchange will average the locational clearing prices: end use customers served by the Exchange will see one clearing price. The net payments to the Power Exchange will be disbursed through the ISO to pay for transmission losses or as congestion payments under transmission congestion contracts.

3. Participation in the Power Exchange

Recently, we have given considerable thought to the degree to which participation in the Power Exchange should be voluntary. We can find no reason why participation should not be wholly voluntary for all buyers and sellers other than the investor owned utilities jurisdictional to this Commission. A number of factors which we will now describe persuade us that for the five year transition period during which they seek recovery of their stranded generation assets and power purchase liabilities, our investor owned utilities should be required to bid all of their generation into the Power Exchange and satisfy their need for electric energy on behalf of their full service customers with purchases made from the Exchange.[19] Such a temporary requirement will dramatically reduce the scope and burden of the regulatory issues associated with determination of the dimension of the assets which are non-competitive in a transparent market, ensure that those customers who elect to rely upon their distribution utility to procure their

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[18] In the hub-and-spoke implementation, the spot price would be the nearest hub price with a transmission charge to move between the customer location and the hub.

[19] It is worthy of emphasis that from the perspective of end users no Californian is obliged to depend upon the Power Exchange to set the economic terms of their consumption. Even those who elect to remain as full service customers of the distribution utility are free to engage in contracts for differences with any person or entity who will guarantee a cost structure wholly independent of the clearing price realized by generators who have bid into the Exchange. Even more dramatically, eligible end users can sever themselves from the Exchange and the procurement services of the distribution utility by forming, directly or through a middle-person, a direct access contract so as to shift their load to generation which will be nominated directly into the ISO. So from the buyer's perspective the Power Exchange is a voluntary, optional market institution on day one.

electric energy will receive the benefits of those competitive market prices, and provide a sufficient depth to the Exchange that its market signals may be relied upon as a benchmark for choices to opt for contracts for differences or direct access arrangements.

These goals of consumer protection, ensuring the integrity of the compensation request protected by the competition transition charge, reduction of the nature and complexity of future regulation, and nurturing the advent and maturing of market signals suggest that it is useful to think of participation in the Power Exchange in three distinct time frames:

1. the initial period when there is little if any experience with market conditions and functions;

2. the five-year period identified as a transition between the regulatory order which is passing and the competitive climate we seek to foster; and

3. the post-transition period.

A refusal to make this distinction imposes the risk of withholding support for infant mechanisms as yet untested and experienced by market participants or perpetuating the presence of such supportive structures after customer and supplier sophistication has rendered them unnecessary.[20] Fidelity to the distinction convinces us that in the initial period the jurisdictional utilities must be

[20] A useful analogy may be made to state and federal laws respecting the issuance of new securities. The integrity of the markets has long been recognized as the key to widespread investor participation and this is particularly true of small investors who lack the means or opportunities to gain access to non-public information. The Securities Act of 1933, 15 U.S.C. § 78a et seq. imposes a registration requirement on issuers, underwriters and dealers with respect to new securities. As described by the Securities and Exchange Commission, this registration requirement is intended ". . .to provide adequate and accurate disclosure of material facts concerning the company and the securities it proposes to sell. Thus, investors may make a realistic appraisal of the merits and the securities and then exercise informed judgment in determining whether or not to purchase them." Securities and Exchange Commission, The Work of the SEC 5-8 (1986). The exemptions from the registration requirement are predicated upon a demonstration of sufficient investor sophistication and access to information as to no longer warrant this initial protection.

required to sell their generation into the Exchange and make purchases of electric energy on behalf of full service customers from it. During the transition period, any generation unit sold by the utility by way of divestiture to a non-affiliated new owner will be immediately freed of any obligation to bid into the Exchange. Participation by the new owner will be totally voluntary. At the end of the transition period, when the determination of the assets which qualify for recovery under the competition transition charge has been finalized, the utility will be free of any mandatory requirement that it either sell into or buy out of the Exchange. By that time we anticipate that the sophistication of sellers, brokers, aggregators and end users will have developed equivalent if not superior means of gaining access to pricing information and the comparative advantages and disadvantages of using the Exchange as a market mechanism.

a. The critical role of transparent, reliable price signals:

Looking more closely at the role of the Exchange we find it useful to distinguish the value or benefit which we expect it to confer upon a variety of market participants. On the day it begins to function the Power Exchange will be the market institution in which all generators are able to compete on the basis of short run incremental electricity costs in an open setting and on what is literally a level playing field. Equally important, all buyers of electric energy will derive basic consumer protection in their ability to freely monitor the results of that competition. The transparent price will also be revealed in what we have termed "real time" so that clear market signals can be sent to buyers and end users as to the significant difference in the cost to California's economy of meeting our energy needs at any point in the twenty-four hour day. The value of this pricing revelation will be significant after the first week of Exchange operations, but will grow with the passage of time and the acquisition of experience.[21] Once this price is

[21] Over time, as transition costs are eliminated and excess capacity diminishes, the clearing price for the electricity commodity will gradually reflect a value for capacity.

revealed and tracked market participants will begin to develop a confidence and sophistication which will permit them to make key decisions.

(1) The value of price revelation to existing and potential sellers:

Our jurisdictional utilities will gain real experience in determining which of their generating assets clear the market, how frequently, and with what resulting stream of income. As we shall more fully discuss, having this determination made in a open market is critical to gaining end user acceptance of the integrity of the non-bypassable competitive transition charge. Non-utility generators, both within and without California, will be able to use this same information to decide if it is in their self interest to attempt sales into the Exchange or seek direct access customers. Finally, potential generators will see the emergence of a price signal which will point to market opportunities to invest in new generation capacity. As an example, let us suppose a potential market entrant with access to a gas supply and computations which project the cost of generation with a state of the art combined cycle turbine at three cents. Knowledge that the Exchange is clearing eighty percent of the time at three and one half cents and above is precisely the type of information needed to develop a business plan to enter the market and obtain financial backing for such a step. This information is equally vital to a utility or non-utility owner of existing units with respect to the feasibility of a repower.

(2) The value of price revelation to buyers:

Our vision of a market dominated by vigorous competition is wholly dependent upon the availability of timely, reliable and affordable information upon which customer choice can be intelligently made. Throughout this proceeding we have been challenged to devise institutions and protocols which will enable customers of every class and potential load profile to gain the benefits of enhanced competition among generators and the efficiency gains of a unified and independent operator of the transmission network.

While it is relatively easy to trust in the ability of large users to attract the attention of rival sellers, the circumstances of California's residential and small load commercial and agricultural ratepayers cannot be projected with comparable confidence. Throughout our history this Commission has been given the responsibility of fostering the well being of these ratepayers and we cannot abandon them with the simple expedient of dubbing them "customers." At least initially, most observers anticipate that a significant majority of residential and small load commercial and agricultural users will either prefer, or lack competitive alternatives to, reliance upon the local utility to procure electric energy as well as provide distribution and related services. These average ratepayers may be referred to as "full service customers." During the transition period, we have concluded that our greatest contribution to those who initially elect or find no alterative to the status of full service customers is to ensure that they gain access to the competitive price for generation in a manner that is free of cost and confusion. We have accomplished this by our requirement that the distribution utility must simply pass on to these customers the cost of electric energy as revealed by the Exchange over the billing cycle. Full service customers are then given the option to have their bill computed as the average of the Exchange price times consumption or elect the virtual direct access option in which the Exchange price is matched against the time of use in which the customer's consumption occurred.

Customers who desire stability or certainty over time will find the revealed Exchange price signals vital to electing among an enhanced set of options. A customer who, for any reason, desires a price structure which differs from the day by day, hour by hour, revelation in the Exchange will be afforded the opportunity to purchase a financial hedge or "contract for differences" from any counterpart party who may or may not own or have contractual rights to any specific generation. Even more dramatically, such a customer may elect a direct access contract. But irrespective of the alternatives, the only way in which choice can be effectively made is for the potential buyers and sellers to compare the costs, terms and conditions to something readily known and reliably revealed. Until they have gained sufficient experience or devised alternative means to gain discovery over comparable information, that ready available and reliable reference point is the alternative of wholesale transactions revealed through the Exchange.

b. Allowing utilities to opt for non-Exchange purchases and sales during the transition period disguises pricing information and requires contentious regulatory proceedings to validate the dimension and legitimacy of the competition transition charge:

During the transition period both the transparency and reliability of the pricing signals will be seriously compromised unless the jurisdictional utilities are obligated to bid their generation units into the Exchange and procure the electric energy needed to supply their full service customers from it. Consider the most extreme example of an Exchange which is wholly voluntary from the perspective of the jurisdictional utilities on day one. Such a strategy would enable the potential market participants with the most concentrated market power to buy or sell electric energy through bilateral contracts. There would be no price revelation and consequently no price signals manifest to any party who was not a counterpart to such a contract. Even contracting parties would be mostly in the dark for they would have no direct knowledge of the terms contained in other deals.

If the utilities opted to make the bulk of their purchases on behalf of full service customers through bilateral contracts, those customers most vulnerable to an abuse of market power would have no means of tracking the cost of the electric power. Only by engaging in contentious reasonableness reviews could this Commission eventually establish information which, by that point, would be months if not years old. The virtual direct access option would be taken away from full service customers or rendered functionally useless given their inability to follow real time price signals. The decision of whether to opt for a contract for differences or to bear the cost of a direct access contract would likewise be compromised by an inability to compare the advantages and disadvantages of these strategies to a transparent alternative.

Beyond the issues of consumer protection and customer choice, there is the legitimacy of the competition transition charge and its acceptance as a non-bypassable obligation by all classes of end users. The issue of generation assets alleged to have been stranded would now be plagued with doubt and uncertainty at the precise time when this Commission would be seeking to ensure the acceptance and collection of a non-bypassable competition transition. Again, complex and probing regulatory proceedings might eventually determine the reasonableness of these claims presented by our jurisdictional utilities but the time delay would protract the transition period and move us away from reliance upon market mechanisms.

On the surface many of these concerns would seem to be mitigated if we indulge the assumption that the jurisdictional utilities would shift only a portion of their purchases and sales away from the transparent Exchange market. But to the extent that they diverted their business they would lessen the confidence on the part of all market participants that the volume of Exchange transactions was sufficiently robust as to convey reliable pricing signals. In economic literature this problem is identified as one of "thin markets." Such a development could actually complicate California's experience with the transition period rather than facilitate it.

We can envision regulatory proceedings in which the market signals emerging from such a partially used Exchange would be blended with what were alleged to be proxy indicators developed from wholly or partially unverified sources. Any verification efforts made during the course of a contested proceeding would doubtless compromise the proprietary interests of the non-utility participant in such transactions adding yet another layer of conflict. Equally important, it would not resolve the issue of the appropriate charges to be passed onto to full service customers by the jurisdictional utilities, nor would it withdraw from the realm of conjecture the fairness with which they marketed generation sales which then resulted in a claim for compensation under the transition charge. In the final analysis adding layers of regulatory fixes strikes us a decidedly regressive response to a proceeding launched in the bid to foster and then rely upon market forces.

4. Jurisdictional Issues Related to the Creation of the Power Exchange

The establishment of the Power Exchange will require close coordination between the FERC and this Commission. The Power Exchange will have the function of bringing buyers and sellers together. Although the Power Exchange itself will not "sell" power, it will establish market prices for sales for resale.

The Federal Power Act (FPA) confers exclusive jurisdiction over rates, terms, and conditions for sales for resale (wholesale sales) on the FERC. Retail sales, even if the power originates out-of-state, are subject to exclusive state jurisdiction.

Because the power bid into the Power Exchange may be sold for resale, pricing mechanisms, including bidding protocols, will be subject to FERC's oversight. At the same time, the FERC lacks authority over generation assets that were built to serve retail customers and are currently in retail rate base and reflected in retail rates.

It is our intention to impose incentive ratemaking on certain generation assets. Our authority to apply PBR to generation assets where power from those assets is subject to FERC pricing authority has been questioned.[22] In our considered opinion, subjecting the underlying generation assets to a PBR mechanism to ensure reasonable rates does not result in a conflict with the FERC, particularly since the FERC has no authority under the FPA over the generation assets themselves.

The legal framework established by Congress in the FPA did not contemplate the market structure we propose today. Therefore, to foreclose the possibility of litigation and attendant delay of restructuring on this issue, we recommend that the utilities ask, as part of their application to the FERC to establish the Power Exchange, that FERC accept and grant deference to the PBR revenue requirement determined by this Commission for the utilities' generation assets that make sales through the Power Exchange.

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[22] See Comments of CMA, July 21, 1995.

C. Ownership and Structure of the Independent System Operator and the Power Exchange

Our restructuring framework rests on the establishment of two entities, the ISO and the Power Exchange, that we have determined must be legally separate from all investor-owned utilities. Issues related to the organizational structure of the entities and who will own them must be addressed prior to seeking FERC's approval of their establishment. The structure of these two entities should be evaluated jointly, because they will be operating in close connection, each depending on the other to perform critical functions. The Power Exchange will be functioning as part of the generation market in which many competitors, including independent generators, utilities, and aggregators, will vie to supply the same commodity. Therefore, to some extent, competition will require efficient operation of the Power Exchange.

If the Power Exchange is to be a for-profit entity, restrictions should be put in place to prevent potential conflict of interests by requiring complete separation of the Exchange from any competitor or bidder in the Exchange. This task may be difficult, since design and operation of the Power Exchange will require significant cooperation among participating parties, and any decision that appears to give an advantage to any bidder could be perceived as a biased decision, reflecting some real or imagined self-interest on the part of the owners of the Exchange. A for-profit Power Exchange would require regulatory oversight to ensure it did not improperly exert its influence over any Exchange transactions. For these reasons, the Power Exchange may be perceived to be more impartial if it is owned and operated by a nonprofit or governmental entity charged solely with creating the most efficient exchange.

The ISO will operate as a monopoly (at least for the foreseeable future) and as such its function will be subject to FERC's regulatory oversight. If the ISO is organized as an investor-owned utility, it could be regulated as other investor-owned utilities are. However, the ISO should not be affiliated with generation providers or any of the utility distribution companies. The ISO could also be created as a nonprofit entity or governmental entity.

For both the Power Exchange and ISO necessary revenues can be acquired from a small fee added to each transaction as a volumetric or cost-based charge. The initial working capital of these entities might be derived from utility contributions, or from a loan approved by the appropriate regulatory agency.

We direct PG&E, SCE and SDG&E to include in their proposals for the establishment of Power Exchange and the ISO recommendations for ownership, organizational structure, and working capital of the two entities.

D. The Opportunity for Customer Choice

The opportunity to choose from an array of goods and services makes it more likely that individual customers make arrangements that meet their particular needs. Today, we move toward an industry which offers three avenues for increased customer choice in electric services.

First, we implement a transitional phase of direct access in which a representative group of retail customers can choose to arrange the purchase of electric generation services at negotiated prices directly from nonutility generation providers, including marketers, brokers, and supply aggregators. We expect that this transitional phase will lead to the availability of direct access to all retail customers.

Second, we make available real-time and time-of-use rate options to customers who have the appropriate metering equipment. Both of these choices provide electricity consumers with the opportunity to make informed decisions about the electric services they wish to receive.

A third choice exists in the opportunity for customers to arrange contracts for differences, which allow the parties to allocate the risks associated with market uncertainty. We discuss these choices in greater detail below.

1. Implementation of Direct Access

In comments to the May proposals and the MOU, most of the parties expressed a preference for the opportunity to purchase generation services at negotiated terms and conditions directly from suppliers, including brokers and marketers. Today's decision makes considerable progress in resolving the concerns expressed by the majority in May about the conditions that were necessary predicates for direct access. We recognize that not all concerns can be satisfied at this stage of the industry's transformation, but at this foundational stage of restructuring we should not be overly prescriptive in attempting to resolve all issues. To a great degree, we must turn to the stakeholders and market participants to discern the problems, define the issues, and recommend appropriate solutions.

No later than January 1, 1998, simultaneous with the implementation of the Power Exchange and the ISO, we will begin a phase-in of direct access. An initial phase of direct access will last for a period of twelve months, after which we will make the direct access option available to *all* customers at that time and we expect all customers to have that option within five years.

Implementation of this initial phase of direct access provides a measured approach to this new competitive framework and allows the market to (1) address any operational issues, (2) measure the effectiveness of the program, and (3) improve the program in order to offer it to an increasing number of electricity consumers. During the initial phase, and as part of our continued effort to allow retail competition to all market participants, the Commission will evaluate these and other issues. Barring technical concerns, we fully anticipate that a majority, if not all, of California electricity consumers will have the opportunity to purchase generation services directly <u>no later than five years</u> from the implementation of the initial phase of direct access. Each customer class will be represented in each year and phase. In the absence of agreement for earlier implementation, we adopt the following schedule for phasing in direct access for all three investor owned utilities at dates no later than:

Total Number MW Available for Participation in Direct Access Program

	SCE/PG&E	SDG&E
1998	800	200

1999	1,400	350
2000	2,200	550
2001	4,000	1,000
2002	8,000	2,000
2003	All remaining load	All remaining load

a. Required Elements of Direct Access

Implementation of direct access will be subject to the following requirements.

1. Customers in all classes shall have a fair opportunity to participate in each phase of direct access.

2. Aggregation is voluntary and may include the loads of multiple customers or a customer may aggregate loads at several sites with appropriate identification of location consistent with the requirements of the dispatch. Aggregation may be limited to a particular customer class or may include customers from different classes.

3. Third-party intermediaries, such as power marketers and brokers, will be able to purchase unbundled electricity from individual suppliers and bundle that with various energy services to meet the customers' specific needs or unique operational requirements.[23]

4. Suppliers or third-party intermediaries must ensure that appropriate metering equipment is in place.

5. Supplies arranged by direct access contracts will be scheduled directly with the ISO. Suppliers who have arranged direct access contracts will be required to comply with the operating protocols of the ISO, but they will not be required to disclose any information about their costs of generation or the negotiated price for the sale. They will be allowed to submit increment or decrement bids for use in any redispatch determined by the ISO.

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[23] See Section VIII for our discussion of regulatory oversight and consumer protection with respect to supply intermediaries, e.g., marketers and brokers.

6. Suppliers or third-party intermediaries and direct access customers will be responsible for the costs of ancillary services and other charges as communicated by the ISO.

b. Eligibility for Direct Access

Of primary concern to consumer groups is the issue of equitable access to the competitive generation market for small customers. Many parties have commented that the phase-in of retail competition as proposed by the MOU would primarily benefit large customers. They argue that the MOU's restrictions on participation disadvantage both small customers and aggregators and their customers who want to pursue retail contracts.

Allowing the aggregation of small commercial and residential customers, as well as the individual participation of small commercial and residential customers, is vital to ensuring that consumers have the opportunity to participate and benefit from consumer choice. Therefore, eligibility in the initial phase of direct access will be open to a representative number customers from *all* customer groups. We view the MOU's suggestion of an 8 MW threshold limit applied to individual customers and aggregated customer groups for the initial phase as a reasonable eligibility parameter. However, we note parties' reservations similar to those expressed by the Division of Ratepayer Advocates:

> The MOU limits eligibility for direct access, but states no principle which supports limited eligibility. Presumably, the justification for limited eligibility lies in technical limits . . . . The Commission should resolve the difference between an unprincipled limit and a principled call for choice by having the parties work to determine what technical problems reduce how many customers can choose their supplier.[24]

We direct the utilities to confer with parties and recommend eligibility parameters in the initial phase of direct access.

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[24] DRA comments to the MOU, filed October 2, 1995.

Parties should carefully consider whether our minimum phase-in schedule is necessary or whether eligibility can be held open to all electricity consumers after the twelve-month initial phase. If a phase-in schedule is deemed necessary, we ask parties to recommend an eligibility phase-in schedule for direct access beyond the initial phase, but not later than the five-year minimum schedule already stated. We do not favor restrictions beyond those necessary due to technical obstacles, though we recognize that some parties may have additional concerns. Modifications to an adopted phase-in schedule will be subject to any changes found necessary in the Commission's review of the initial phase and the parties' recommendations.

As entities not subject to our jurisdiction in these proceedings, municipal utilities and other government entities must make their own decisions with respect to customer choice options, including the availability of physical bilateral contracts.

c. The Utility as Generation Service Provider

Utilities will continue to have direct control and operation of their distribution system, power production, and procurement of generation services for their customers. They will also continue to own, but not operate, their transmission facilities. These utilities are referred to as utility distribution companies (UDCs). In addition to providing distribution service to all customers, the UDCs will serve customers who choose to remain utility service customers. This Commission will continue to regulate the rates, terms, and conditions of those services. We discuss in greater detail our regulation of the UDCs in Section III.E.

After a five-year transition period, UDCs will have the option of purchasing all or a portion of their electric needs from the Power Exchange or from other sources, including nonutility generation providers. They will be able to choose the level of their participation as buyers in the Power Exchange. In serving the load of any customers who do not choose to be direct access customers through another supplier, utility purchases through the Power Exchange will be considered prima facie prudent.

Self-dealing retail contracts prohibited: PG&E, SCE, and SDG&E, as distribution utilities, may not enter into retail contracts to purchase the output of a generation facility that is under their own or any of their affiliates' ownership.

Existing utility generation assets will undergo a Commission-reviewed market valuation process within the first five years of the establishment of the new market structure. After the completion of this process, the utility may still retain ownership of certain generating assets through affiliation. Thus, vertical market power could still exist between the distribution utilities and generation companies through ownership or affiliation.

Furthermore, a distribution utility has access to considerable information about its customers, their load profile and other related data. This information could be very valuable for marketing of generation services and if provided exclusively to the utility-affiliated generating company, could give that company an unfair advantage in the market. To ensure that a distribution utility affiliated with a generation company does not exercise market power abuses in a manner that advantages its generation affiliates, we will prohibit any contracts between the distribution utility and its affiliated generating companies.

d. Service to Direct Access Customers Returning to Utility Service

In this newly restructured industry, some customers will pursue retail contracts with suppliers or intermediaries while other customers will prefer that the utility continue to procure those supplies on their behalf. The UDC will retain its obligation for least-cost procurement for these utility service customers. The UDC's least-cost procurement obligations will be met by purchases through the Power Exchange.

The UDC also has an obligation to provide distribution services to all customers. The UDC will no longer be obligated to plan for or provide generation service to direct access customers.

With respect to the UDC's obligation to serve direct access customers who wish to return to utility service, we are faced with a recommendation contained in the MOU that makes a distinction between residential and non-residential direct access customers.

> *Nonresidential consumers wishing to return to UDC procurement service:* A non-residential consumer who wishes to return to utility service may do so if the utility agrees to accept the nonresidential consumer back and offer service. The rates, terms, and conditions of the service offered the returning nonresidential consumer would be those agreed to by both parties to the negotiation and would be subject to Commission approval.
>
> *Residential consumers wishing to return to UDC procurement service:* For residential consumers who have procured their own power supplies but later wish to return, the UDC will have a tariff that sets forth the rates, terms, and conditions governing the service to which direct access customers could return. The UDC would, to the extent possible, base its "return tariff" on market prices for generation. The UDC would be required to offer the service thirty days after the returning residential consumer has formally notified the UDC of the desire to return. The UDC has the option of negotiating rates, terms, and conditions of return with a returning residential consumer, subject to Commission approval.

We have given these recommendations considerable thought and have decided to reject them. In a mature commodity market, customers daily exercise a right of free entry and exit. The UDC faced with an individual or entity wishing to return as a full service customer need only increase its purchases from the Exchange. Should it be objected that increased demand on the Exchange may occasion the dispatch of a bidder who otherwise would not have cleared the market with the consequence that the payments to all bidders are adjusted to that clearing price, we respond that this an inevitable experience with free markets.

2. Jurisdictional Issues Related to Direct Access

In addition to the federal/state jurisdictional issues of authority over unbundled retail transmission and the demarcation between transmission and distribution discussed above, retail competition also raises the issue of whether a state may order utilities to provide retail customers access to alternate suppliers. The direct access option also raises issues of reciprocity and supply of inexpensive power affecting surrounding states.

a. Authority to Order Direct Access

The attitude of California's three largest investor owned utilities appears to have eliminated the primary jurisdictional issue raised by retail competition, the question of state authority to order utilities to provide retail wheeling services. SCE is a joint sponsor of the MOU and although the recommended market structure may not have represented their preferences, both PG&E and SDG&E appear willing to accept it. We applaud the two non sponsoring utilities for their flexibility. We authorize the utilities to provide delivery services to direct access customers, under tariffs approved by both the FERC and this Commission, upon written agreement by the direct access customer to pay its share of retail stranded costs, as determined by this Commission.

b. Reciprocity

One of the chief objections to retail competition as outlined in the Blue Book was that out-of-state suppliers would have the opportunity to serve California retail customers directly and yet California entities would have no assurance of reciprocal competitive opportunities in neighboring jurisdictions. SCE is on record as suggesting that the FERC could approve a reciprocity provision in the California utilities' open-access transmission tariffs.[25] While we will not preclude a utility from making such a request such action would be without our blessing. The question of the pace and extent of market reform to be undertaken by our sister states is an issue which must be resolved by duly constituted governmental authority in those jurisdictions. We are content to invite the participation by out-of-state generators for it is our desire that the Exchange and the transmission grid be maximized in affording competitive entry into our markets.

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[25] See, e.g., SCE's Brief, January 31, 1995, p. 70.

There is, however, an issue of reciprocity which arises within California. We have previously acknowledged that we do not have the authority to impose our vision of a reformed and reregulated market on municipal or public power entities. Under legal mandates which we scrupulously respect the governance of these entities and their relation to their customers are committed to their duly constituted governing authorities. But we do have both a right and a responsibility to promote what some have termed a "level playing field" insofar as the well being of California's investor owned utilities are concerned. To this end, we will not require our jurisdictional utilities to tolerate the formation of physical bilateral contracts with customers within their service territories and California municipal or public power generation unless the entities which own that generation extend reciprocal rights to investor owned utilities with respect to their customers.

3. The Option of Real-Time and Time-of-Use Rates

Currently, ratepayers may not be aware of the fundamental fact that over a twenty-four hour period the demand for electricity varies dramatically. The consequence is that utilities invest in and ratepayers defray the cost of a system that must be built to meet peak demands that are generally experienced from two o'clock to six o'clock on any given afternoon. At all other times, the system is underutilized and investment is underproductive.

Most customers purchase electricity at a rate which represents the average cost of electricity. Some customers have the opportunity to purchase electricity at real-time or time-of-use (TOU) rates which allow them to see the price of electricity at specific time periods of the day so that they can alter their electricity use to less expensive time periods or off-peak hours in order to reduce their cost of electricity.

The May pool proposal recommended providing the choice of "virtual direct access" to all customers. Under this option, customers could purchase electricity on a rate scheme reflective of their usage in real-time or time-of-use increments, or alternatively, one which averaged the cost of electricity multiplied by the monthly consumption figure.

We affirm our belief that this billing option constitutes a valuable customer choice and note with pleasure its adoption as part of the restructuring effort in the Australian State of Victoria. With the Exchange publishing market-clearing prices for the various locations, jurisdictional utilities shall offer an optional tariffed electric service which references the appropriate real-time market-clearing price.[26] The revelation of the real-time price of electricity coupled with a rate alternative that allows the customer to respond intelligently will produce savings for any customer who is able to shift demand from peak to off-peak hours. The potential that many customers will respond to this opportunity to take significant control over the cost of their consumption will produce a collective benefit, in that demand will be redistributed away from the current peaks. Future generation demands will be forestalled even as existing investments in generation are made more productive. The result is a triple win, embracing the individual consumer of any class who is able to reduce costs by shifting load, the society at large which defers the demand for new generation, and investors in existing plant and equipment who see it put to more productive use.

We direct that the utilities offer real-time rate and time-of-use rate options not later than January 1, 1998. The utilities should propose such an offering to a representative group of customers from all customer classes or to all customers.

a. Real Time Pricing and Time-of-Use Meter Service

We recognize that the availability of time-of-use or real-time pricing options, whether pursued in the context of virtual direct access billing election or direct access contracts, is inhibited by existing technologies and the availability of enabling technology which requires RTP or TOU meters.

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[26] While efficiency gains would be achieved by requiring that TOU and real-time rates be mandatory, it is our present intention to make them optional. A customer would be given the choice of a rate scheme which reflected usage of electricity in real time or one which averaged the cost of electricity multiplied by the monthly consumption figure.

We adopt a five year plan for installing the necessary meters for customers other than those who are categorized within the Domestic, GS-1, and TC-1 customer groups. Customers within these three categories will not be required to purchase or install such meters but may do so on a voluntary basis.[27] Such a plan is consistent with our adoption of the MOU's phase in schedule for direct access. All utilities should have the same schedule for meter installation. With several significant exceptions, we adopt the following schedule based on maximum demand as a minimum requirement:

500 kW	by 1998 when restructuring begins
400 kW	one year after restructuring begins - at least by 1999
300 kW	two years after restructuring begins - at least by 2000
200 kW	three years after restructuring begins - at least by 2001
100 kW	four years after restructuring begins - at least by 2002

All customers will be individually responsible for the cost of the meter installation, and can opt to pay for it on their bill in reasonable installments that avoid severe bill impacts or hardships.

Our schedule is not intended to prevent certain customers from enjoying the benefits of real time pricing with or without a financial hedging contract (such as a contract for differences), but rather provides an orderly approach to installation. Those customers who are not yet scheduled for utility meter installation may purchase and install such meters at their own

[27] Full service customers who desire to avail themselves of the virtual direct access billing option will have to install an appropriate meter and may elect to pay for it in a lump sum or have the cost deferred over monthly installments added to their bill from the distribution utility. If a customer from an otherwise exempt customer group elects to participate in direct access it will be necessary to arrange for the installation and use of appropriate metering equipment if required by the terms of the direct access contract.

expense, but would not be thereby become eligible for direct access any earlier than their scheduled year.[28]

Our primary concern, is that our oversight of the utility includes the assurance that these services meet specific service, safety, and reliability standards. Therefore, we are requiring the investor owned utilities to install the new RTP or TOU meters. Assurances of these standards, in our view, must continue in a competitive market, although they may require our oversight responsibilities. Pending the adoption of performance specifications and protocols which assure the functional quality of such devices, the utility will continue to provide metering service for all utility service customers. We will refer to the Working Group the issues surrounding metering standards. They should also address the confidentiality of customer metering data. We will issue a ruling setting forth the workshop schedule and agenda.

4. Procedural Issues

PG&E, SCE and SDG&E should file their proposals for direct access in this docket within 30 days after the effective date of this decision. In their filings, the utilities should propose an eligibility schedule for both the initial phase of direct access and any subsequent phases. Proposals should reflect the principles for direct access and real-time and time-of-use rate options outlined in this decision. We note that these proposals will require coordination with proposals for the ISO as well as with the proceeding on unbundling of utility transmission and distribution functions.

5. Other Contractual Arrangements

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[28] So long as the meters installed meet the metering standards (technical specifications) of the distribution utility, customers could have meters installed by others (e.g., suppliers, aggregators, or meter vendors). One means of facilitating this option would be for distribution utilities to develop approved vendor lists once the standards are established.

At this time we wish to clearly affirm our encouragement of any contractual arrangements which may prove congenial to consenting traders who wish to manage risks associated with the revelation and realization of the market-clearing prices published by the Power Exchange. Such contracts are called contracts for differences (CFDs) and have been referred to by a variety of parties to our Rulemaking to describe the potential for private agreements that hedge the cost of electricity over time. Our support of contracts for differences is not intended to limit the dynamic of the marketplace in devising financial instruments for the purpose of assuring individual or group users that the economic consequences of their usage of electricity will not depend upon the vagaries of the market-clearing price revealed by the Exchange.

Because they would have an unfair advantage over other traders with regard to their own generation facilities, we prohibit the utilities from arranging CFDs with their own generation facilities and affiliated generation facilities. CFDs arranged by the utilities are subject to Commission review. All other nonutility CFD transactions are outside this Commission's purview.

E. Our Continued Regulation of PG&E, SCE and SDG&E

Our restructured industry would require PG&E, SCE and SDG&E to operate under the competitive forces of the market. To operate efficiently in this environment, participants must be responsive to rapid changes in the market. Existing cost-of-service regulation has become too complex and difficult in many ways to allow us to regulate the utilities properly in this fast-moving industry.

Our goal is to have an improved regulatory process that offers flexibility and encourages utilities to focus on their performance, reduce operational cost, increase service quality, and improve productivity. At the same time, we must ensure that safety, quality of service, and reliability are not compromised. There is broad but not universal consensus that Performance Based Ratemaking (PBR) can accomplish these objectives by providing clear signals to utility managers with respect to their business decisions and helping them make the transition from a tightly regulated structure to one that is more competitive. Under PBR, utility performance is measured against established benchmarks. Superior performance, above the benchmark, would receive financial rewards, and poor performance would result in financial penalties to the shareholders. By providing financial incentives to utilities, we will encourage them to operate more efficiently to maximize their profits.

In the Blue Book proposal, we stated our objective of replacing traditional cost-of-service regulation with PBR in areas where competition is not yet developed. Our objective was to seek new ways to reduce regulatory interference with management decisions and to allow utilities more flexibility in their day-to-day operations. We noted that although cost-of-service regulation has served our regulatory objectives reasonably well in past years, it is no longer compatible with the changing electric industry and is in need of reform. The high cost of electricity in our state compared to the rest of the nation, about 50% above the nation's average rate, gave us a clear indication that the current regulatory scheme was in need of change. Numerous parties to this proceeding have supported our objective of moving away from cost-of-service regulation. Most agree that significant productivity gains can be achieved in the utilities' operation by providing incentives to utilities to focus on their performance. Overall, the existence of an incentive, such as shareholders' financial rewards and penalties, could encourage utility managers to do a better job. The May proposals acknowledged our commitment to PBR and proposed to apply PBR treatment to the operation of utility generation and distribution assets.

Our proposal today reaffirms that commitment. Our policies continue our movement toward a regulatory environment that is based on encouraging efficient operation and improving productivity, rather than on reasonableness reviews and disallowances. In this decision, we emphasize the Commission's commitment to replace cost-of-service regulation with incentive mechanisms. An example of our commitment is the allowance of continuation of several PBR mechanisms that have been adopted on an experimental basis for various aspects of utility operations. In addition, we propose to replace cost-of-service regulation for other aspects of utility operations with PBR. These include utility distribution services and some of the utility-owned generation costs.

At this point, we lay out basic and key principles, consistent with the provisions of Assembly Concurrent Resolution 143, for various incentive mechanisms that would focus on capturing benefits for all electric customers who receive service from PG&E, SCE and SDG&E in our restructured industry. While these principles apply equally to the three utilities, we repeat our earlier assertion that each utility's unique circumstances should be considered in designing a detailed utility specific PBR mechanism. We ask the utilities to file, as set forth later in this discussion, applications to assist us in designing new PBR mechanisms to accommodate the new market structure, and we also ask them to provide comments regarding the impact of our decision on pending PBR applications.

Our proposal today unbundles traditional utility services into generation, transmission, and distribution functions. We propose to replace the traditional cost-of-service regulation with incentive regulation for those utility services that continue to remain under this Commission's oversight after industry restructuring has occurred. Under the new market structure, we see two areas of utility operation that require our continued regulatory oversight and where incentive regulation could appropriately replace cost-of-service regulation. These include utility distribution services and utility-owned generation. Below we describe each mechanism in more detail.

1. Utility Distribution Services

Under the current regulatory structure, utilities own and maintain the electric lines that distribute electricity to end-use customers in their service territories. Utilities are responsible for providing nondiscriminatory distribution services to all customers. In the restructured industry, they would continue their obligation to provide distribution services to all customers, including direct access customers, in their service territories. A distribution PBR would focus on utility performance with emphasis on providing nondiscriminatory access to all customers. It would also focus on ensuring that the utilities continue to provide quality distribution services and do not jeopardize service reliability or safety as it relates to distribution.

2. Utility-Owned Generation Assets During the Transition

Our proposal for a new industry requires that the utilities bid all their generation assets (with the exception of must-take power) into the Power Exchange until 2003. Our proposal also contemplates a five-year transition period during which some utility generation assets will remain under the ownership of the utility and our regulation, while others undergo a market valuation process and possibly a transfer of ownership.

During this interim period, we propose a generation PBR for some utility generation costs, consistent with our instructions for transition costs in Section V. A generation PBR would provide an incentive for the utilities to earn financial rewards for efficient operation of certain generation plants that are necessary for transmission stability.

a. Transfer or Sale of Utility Generating Assets

As described in Section V, the utilities' generating assets will undergo market valuation during a five year period starting on January 1, 1998. During this time, we will continue to have regulatory oversight of utility generation. The MOU appears to assume that market valuation of a generation asset terminates the dedication to public use that is a hallmark of public utility property. The MOU states, "Once a utility asset has been subject to a market valuation . . . , the asset will no longer be utility property subject to [PU] Code Section 851, and the owner will be free to market the power."

We find the MOU's statements about § 851 to be incorrect. Section 851 has two paragraphs. The first requires the Commission's approval before a utility may "sell, lease, assign, mortgage, or otherwise dispose of or encumber the whole or any part of its . . . property necessary or useful in the performance of its duties to the public . . . ." The second allows the sale or disposition, without the Commission's prior approval, of "utility property which is not necessary or useful in the performance of [the utility's] duties to the public . . . ." Utility property, such as a generation asset, that has received revenue recovery through rates, is presumed to be used and useful in the performance of the utility's duties to the public. The mere act of undergoing market valuation does not alter that presumption. If the market valuation is undertaken as part of the spinning-off of the generation asset, of course, the Commission would be asked to make the determination required under the first paragraph of § 851. Our point is that it is the Commission's determination that utility property is not "necessary or useful" in the performance of the utility's duties to the public, and not the act of market valuation, that releases the property from its dedication to public use.

We therefore emphasize that PG&E, SCE and SDG&E must comply with § 851. We also note that utilities' compliance provides this Commission with an opportunity to review and be satisfied that the market valuation process for any given asset was fair and equitable.

3. Procedural Issues

Before the new market structure is implemented, we will continue our regulation of utility generation, transmission and distribution services. During this period, we will allow existing utility PBR programs, specifically SDG&E's base rate and generation and dispatch (G&D) mechanisms,[29] to continue, as approved, until transition to a new restructured electric industry has taken place. SDG&E may use existing PBR dockets to request reforms to its PBR needed by 1998.

SCE and PG&E[30] filed PBR applications prior to the issuance of the industry restructure. In the case of SCE's transmission and distribution PBR application the Commission has started the review process by holding hearings. We believe the parties, the utility, and our staff have put valuable effort into reviewing SCE's proposal. Therefore, we ask SCE and interested parties to

[29] The Commission approved a base rate PBR for SDG&E in D.94-08-023 and a G&D mechanism in D.93-06-092.

[30] SCE's Application, A.93-12-029 and PG&E's Application, A.94-03-008 for a Regulatory Reform Initiative

file comments in A. 93-12-029, addressing whether SCE's pending proposal should be amended or reviewed as originally filed. In addition, SCE has filed A.94-01-016, requesting a Gas Cost Incentive Program for certain gas purchases. We direct the parties to file comments regarding this application addressing how this mechanism could be affected by our decision today. Specifically, we ask that the comments include any necessary changes to SCE's pending applications given the outcome of this decision.

The Commission has not started its review of PG&E's PBR application A.94-03-008, and PG&E has indicated an intent to amend that application following this decision. We ask parties to file comments in that proceeding addressing whether PG&E's pending application should be amended.

Finally, in submitting their comments for A.93-12-029, A. 94-01-016, and A.94-03-008, we ask the parties to keep in mind that because utility distribution activities will continue to be subject to regulation after the industry restructure, the PBR mechanisms that would be in effect during the interim should be crafted with flexibility to accommodate the changes of the restructured industry. We direct that all comments be filed no later than 30 days from the effective date of this decision. Additionally, PG&E, SCE and SDG&E shall file, no later than 60 days from the effective date of this decision, separate applications for new PBRs for utility distribution and utility-owned generation services consistent with the principles set forth in this decision and in particular Section V.

IV. MARKET POWER

We introduce competition to the California electricity market with the conviction that it will deliver desirable market characteristics that have not been delivered by the regulated market regime of the past. But because competition is the foundation of this restructuring, we must be concerned that market power could undermine this foundation and negate the benefits of competition. This concern has served as a screening device in our review of policy options and the choices reflected in today's decision. This concern also compels us to take additional steps to ensure that market power does not impede development of a competitive electricity market in California.[31]

Market power is the ability of a particular seller or group of sellers to maintain prices profitably above competitive levels for a significant period of time.[32] The higher prices reduce economic efficiency because they do not reflect an accurate societal valuation of resources given actual resource supplies. An equally important concern is that high prices stemming from market power abuse cause an inefficient transfer of wealth from the consumer to the producer.

Market power in itself is not necessarily costly. It is the abuse of market power that reduces the societal efficiencies of competition. Practically speaking, however, the mere existence of market power can undermine our goals for electric restructuring and should be avoided. The presence of market power carries with it the threat of market power abuse. This threat can stifle entrepreneurial innovation and diversity of customer choice, and requires continued monitoring for market power abuse. For this reason, our restructuring mechanisms

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[31] For the most part we are concerned with potential market power on the part of incumbent investor-owned utilities. We have also considered market power as it applies to other future industry participants.

[32] *cf*. Department of Justice (DOJ)/Federal Trade Commission (FTC) Horizontal Merger Guidelines.

and mitigation programs are designed to eliminate or reduce market power to the greatest practicable extent.

A competitive market mitigates market power abuse by means of contestability. Contestability is the threat that other competitors and new industry entrants will steal market share from any competitor attempting to abuse market power by raising prices. In this instance, if market entry is timely, likely, and sufficient, higher profit margins from the price increase are more than offset by loss of sales volume or market share. Ensuring contestability, therefore, is a direct approach to employing natural market safeguards to protect against market power abuse. The primary means of ensuring contestability are to eliminate any undue competitive advantages to existing competitors and eliminate barriers to entry of prospective competitors.

Our restructuring program involves a transition from cost-of-service regulation to a fully competitive market for generation. In the early stages of this transition, the utilities might retain market power, and a continued regulatory presence might cause market distortions. If our transition is successful, distortions will be minimized and market power abuses will be thwarted until the threat of timely, likely, and sufficient entry is firmly established to ensure a workably competitive electric market.

A. Potential for Market Power in California's Future Electric Industry

1. Vertical Market Power

Vertical market power can arise from ownership or control of more than a single step in the process of production and delivery of a particular product. Control of vertically integrated assets results in barriers to entry if an entity at one stage of the production and delivery process gives preferential treatment to an affiliated entity operating at another stage of the production and delivery process.

In the electric industry, vertical market power generally refers to a single utility controlling generation, transmission, and distribution functions in a specific geographic market. Vertical market power abuse could arise, for example, if system operators gave priority to affiliated generation assets in dispatch and transmission. For purposes of market power analysis, the transmission function is a key link in the chain of production. To a certain extent, the potential for transmission-level market power depends on the success of the FERC's development and implementation of comparable and nondiscriminatory open access tariffs.

Mitigation: Our restructuring program incorporates two features that are crucial for effective mitigation of vertical market power. First, it isolates control of transmission in the ISO. Second, it establishes an independent dispatch ordering mechanism. For independent and transparent dispatch ordering, we create the Power Exchange, which develops purely price-based dispatch rankings. We also allow for development of direct access contracts markets and other markets. Provision for an ISO and independent dispatch results in an *operational unbundling*, in which vertically integrated electric processes are separated and operational control is spread among entities that are independent of the owners of assets in other levels of the chain of production.

The issue of jurisdiction with respect to the regulation of California's investor-owned utilities in a restructured environment has been discussed in our hearings and in this order. As we indicated, we find the institution of the vertically integrated utility seeking to be self-sufficient with respect to generation, transmission and distribution to be rooted in the past and incompatible with emerging markets and opportunities. It is our desire to see California's investor- owned utilities evolve and prosper in those arenas in which they will compete for markets as well and in those areas in which they will retain the functions and responsibilities of a natural monopoly. In our view, generation is an activity remitted to a competitive market in which utility and nonutility entrants and participants will vie for customer allegiance. Transmission retains the attributes of a natural monopoly and will be consolidated, from an operational perspective, in the Independent System Operator. We view distribution as a natural monopoly with respect to serving those customers who do not opt for self-generation or construct transmission and distribution facilities to serve their consumption.

The issue we now confront is whether our jurisdictional utilities ought to adopt a corporate structure which reflects these distinctions. We direct PG&E, SCE and SDG&E to submit written comments on the feasibility, timing and consequences of a corporate restructuring which would be premised on distinguishing their activities and assets with respect to generation, transmission and distribution. Without seeking to limit the form in which such a restructuring might take, we ask them to address a holding company with three wholly owned subsidiaries.

Based on our experience in dealing with transactions between different competitively provided and monopoly services in other industries, separation of transmission, distribution, and generation assets and operations into affiliates would reduce regulatory oversight needed to protect against self-dealing and allow for easier monitoring of any discriminatory preferences to affiliates. Separation would also help facilitate a bright line between state and federal jurisdiction with respect to transmission and distribution. That separation may, however, impose costs. Those costs may include changes in bondholders' credit positions, possible interest rate changes, and changes in tender offer cost or premiums. We want to consider those costs in reviewing utilities' comments.

These comments would be due 90 days after the effective date of this decision. We will await the initial comments of the utilities to gauge the obstacles or disadvantages of increased separation, and weigh them against the potential benefits.

a. System Planning and Upgrades Under the ISO

If a transmission-owning utility were to build new transmission facilities, the new facilities might, by eliminating existing transmission constraints, create a new opportunity for competition from nonutility-owned generation. The additional competition might reduce the opportunities for the transmission-owning utility to profit from generation it also owns.

Even if the ISO controls the operation of the transmission system, if ownership of the transmission system remains with the vertically integrated transmission-owning utility, that utility might be reluctant to build needed new transmission which would allow additional competition with its own generation.

Planning decisions for new transmission facilities and upgrades are necessarily somewhat subjective and are subject to constant updating and second-guessing. If the vertically integrated transmission-owning utility has control or influence over the planning of new transmission or upgrades, the utility might create additions that favor its own generation or harm competitors.

Mitigation: If the ISO could collect costs above the embedded or marginal cost of construction of new transmission facilities, and could use that income to build and own the new transmission facility, it might be possible to build and upgrade economically justified transmission.

b. ISO Balancing Services

A critical question is whether the ISO, in performing its load-balancing functions, will be able to procure services on a competitive basis from any source or whether it will be required to procure generation services only from generators bidding into the Power Exchange. Load balancing is an ancillary service and FERC will set rates for that service. We intend to participate in the applications before FERC to establish the ISO to ensure that load balancing can, as currently contemplated by FERC, be self-provided, provided by a third party, or provided by the ISO at competitively procured rates, and that the protocols for provision of load following are nondiscriminatory.

c. Utility Ownership of Natural Gas Distribution Facilities

SDG&E and PG&E have a further potential to exercise vertical market power because they are dual utilities, having interests both in the generation of electricity and in segments of the natural gas market. Natural gas fuels the most efficient and accessible generation technologies available to existing industry participants and prospective industry entrants. Discrimination in the price and availability of delivered natural gas could create a significant barrier to entry to industry contestants who depend on reasonable and fair gas prices and availability to compete.

Mitigation: In general, existing conditions in the market for natural gas make it unlikely that dual utilities could effectively engage in vertical market power abuse. We will monitor this in conjunction with our regulatory responsibilities for gas services, and respond if the circumstances change.

d. Utility Energy Procurement and Ownership of Generation Facilities

After restructuring, the distribution utility will still perform an energy procurement function for customers who so choose. The distribution utility and its affiliate generators might share an interest in dealing with each other to the exclusion of other industry contestants.

Mitigation: Until the market structure is fully implemented, all the CTC has been collected and all customers are eligible for direct access, a distribution utility affiliated with a generation company will be prohibited from entering contracts with an affiliated generator.[33]

2. Horizontal Market Power

Market power can take place at any level of the production chain if there are significant barriers to entry or few market participants. This kind of market power is usually referred to as horizontal market power and can be manifested as an ability either to influence prices or to create or maintain effective barriers to entry.

The most common example of horizontal market power is when a single competitor or a small group of competitors owns or controls most of the competitive resources at a particular level of production. Horizontal market power abuse can take several different forms that concern us in evaluating the future competitive market. Our focus is on the generation sector.

a. Market Concentration Analysis

An analysis of horizontal market power begins with an assessment of market concentration. By market concentration we mean how much market participation is dominated

[33] A generator may indirectly provide power to an affiliated distribution company if it is a winning bidder in the Power Exchange. The neutral mediation of the Power Exchange removes market power concerns.

by a small group of firms. Without a sufficient level of market concentration, it is unlikely that potential and existing competitive advantages or market abuses will harm the overall market enough to warrant potentially distorting interventions by us or other government agencies. Many parties have a reasonable suspicion that there is excessive market concentration in electric generation.[34] While this suspicion alone justifies the discussion of potential market power abuses and mitigation options in this decision, we recognize the need for a rigorous empirical market concentration analysis to establish strong conclusions and to verify or disprove this suspicion.

b. Concentration of Generating Facility Ownership or Control

Concentrations of ownership or control of generation facilities can result in market power because a single competitor might control enough assets to alter the supply-demand equilibrium and thus be able to increase prices by withholding generation from the market (decreasing supply). Another manifestation could take place if a single competitor controls an asset or specific block of assets that is indispensable for meeting demand. Many parties, including the FTC and Paul Joskow, note the importance of the "mid-merit order" generating units which are likely to be the units providing the final increment in the supply portfolio. The concentration of ownership of this group of assets might be more important than overall generation concentration. In both cases the powerful entity may control the final increment in the market-clearing supply portfolio and thus control the marginal price for generation.

In addition to mid-merit order generating units, some units may be located relative to the transmission system such that they have an inherent potential for abuse of market power. Some areas, which may be identified and defined by the transmission system once the restructured market is in place, may not be susceptible to immediate entry of lower priced competitors. Entry

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[34] Framework Parties, DRA, Enron Capital and Trade Resources, Inc. (ENRON), and many others have mentioned the problem of generation concentration. Also, as mentioned in the May pool proposal, we recognize problems attributed to the concentration of generation in the United Kingdom pool.

of competing generation in the near term may not be an option because of the need to upgrade transmission or build new generation in that area. We are concerned the mere divestiture of such units to entities other than investor-owned utilities will not decrease the potential market power or exercises of that power that lead to excessive prices.

Mitigation: We are severely limiting utilities' ability to obtain operating costs through the transition cost balancing account for their nonnuclear units. The only operating costs eligible for that account must be demonstrably necessary for reactive power/voltage control. Further, that recovery is limited in time: as soon as market based rates for reactive power/voltage control are established, or the unit is market valued (no later than 2003), that recovery ceases. Utilities may request that operating costs related to reactive power/voltage control be established under a PBR mechanism, which would be designed to further mitigate market power of the units primarily used for reactive power/voltage control. Without these limitations, discussed in Section V, some of the utilities' nonnuclear units would benefit from their location, and could be used as strategic assets to manipulate Exchange prices in certain transmission-constrained areas.

Concerns about the concentrated ownership of generation units by the utilities and the potential for anticompetitive effects resulting from that concentration are particularly acute in the early stages of the restructured industry. The issue of concentration must be addressed early and effectively or the competitive market we envision will not get off the ground. We conclude that market power problems almost certainly will require the existing investor-owned utilities to divest themselves of a substantial portion of their generating assets, particularly their fossil generating plants located within their service territory.[35] Therefore, we will require PG&E and

[35] By referring to fossil units, we specifically exclude other sources of nonnuclear and nonhyrdoelectric generation like Helms and geothermal units. SDG&E's so-called steam units would be considered fossil units, should we subsequently find that mitigation is necessary in its service territory as well.

SCE to file within 90 days of the effective date of this order a plan to voluntarily divest themselves through a spinoff or outright sale to a nonaffiliated entity of at least 50% of their fossil generating assets. Ideally this divestiture would resolve many, if not most, of the market power problems identified by the Department of Justice and FERC, and allow for a competitive market.

To provide an incentive for the utilities to voluntarily divest these assets, we will tie the utility's allowed rate of return on the equity component of the non-nuclear and non-hydroelectric equity component of its transition cost CTC balancing accounts. We will grant an increase in the rate of return for the equity component of up to 10 basis points for each 10% of fossil generating capacity divested.

Utilities will file applications for the voluntary divestiture of fossil generating assets under § 851. In those proceedings, we will review the potential that asset has for exercising locational market power, and will address mitigation strategies intended to relieve or eliminate the exercise of such power.

Additionally, we retain the ability to assess market power concerns should utilities seek authorization for acquisition of new generation or generation rights.

c. Cross-Subsidization

Cross-subsidization takes place when a competitor is able to subsidize competitive operations with revenues from another part of its business or chooses to shift funds from one part of its business to another in order to gain a competitive advantage. In an environment where utilities participate in both the regulated and unregulated sides of an industry, a utility might attempt to use funds from its stable and profitable regulated business to gain an advantage in its unregulated businesses through cross-subsidies.

Specifically, utilities can exploit their regulated markets to obtain leverage in the competitive markets in two ways: they can shift revenues properly attributable to their regulated services to their competitive services, or they can shift costs properly attributable to their competitive services to their regulated services. In both cases, such improper shifting effectively subsidizes the utilities' unregulated services with monopoly profits from its regulated services to the detriment of both monopoly ratepayers and competitors.

Mitigation: Again, limiting CTC recovery of operating expenses is one effective means of preventing cross-subsidization. Additionally and as discussed above, we want to consider the feasibility of separating the transmission, distribution, and generation functions into separate wholly owned subsidiaries, which would allow easier detection of cross-subsidies.

d. Design of PBR/Transition Cost Mechanisms

Parties to our proceedings have devoted considerable attention to problems associated with ongoing transition cost determination based on a market price, in conjunction with PBR treatment for utility assets. Several problems were identified in the transition cost hearings last December. The problems involve the potential that utilities might use transition costs to subsidize operation of plants that are not competitive in the Exchange. This problem concerns us because the subsidization of inefficient generation assets results in a barrier to entry for more competitive industry contestants.[36]

This problem arises because regulatory revenue requirements are based on an average of the operating costs of individual generating units. At any particular moment in utility operations, this averaging means that efficient generating units are subsidizing the operating costs of inefficient generating units. Although this was a prudent regulatory practice in the past, in our transition to competition it conflicts with our intent to ensure optimal market outcomes in the future, return the full value of efficient generating assets to consumers, and ensure market contestability.

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[36] We are also concerned with the loss of societal efficiencies associated with such an outcome.

Although averaging operating costs of production facilities might occasionally be necessary due to lumpy production increments or other factors, competitors are generally inclined to avoid this practice because of the increased costs they absorb.[37] Generally, this disincentive ensures efficient societal outcomes in competitive markets. But ongoing transition cost determination, in conjunction with PBR, has the potential of creating incentives for a utility to subsidize the operating costs of assets that are not cost-competitive in the Exchange if the CTC included those costs.

Mitigation: Our proposal severely limits subsidization of any costs other than the undepreciated, book value (rate base) of nonnuclear, nonhydroelectric generating units. The potential to recover any operating costs <u>at all</u> will be constrained to particular units and particular times when reactive power/voltage support is not yet procurable at market-based rates in locations where it is needed. We need to safeguard the stability of the transmission system to the extent Exchange prices are sufficiently low that a generator critical for reactive power/voltage support could not recover sufficient costs from the Exchange to run.

Further mitigation of this problem might be addressed in design of the PBR mechanisms which utilities may seek to have applied to such units and those limited operating costs.

e. Manipulated Market

Critics of the May pool proposal to create a single mandatory spot market for energy cite, among other things, the ease with which powerful market participants could manipulate prices in such a market. As discussed above, parties have also raised general concerns that the utilities might be able to manipulate prices in the Power Exchange through control of vertically integrated assets, horizontal market concentration, and strategic assets. Parties feared that the potential for these problems might be magnified by a mandatory spot market.

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[37] An exception might be predatory pricing. See later discussion on this topic.

Mitigation: Our proposal mitigates problems of market manipulation by provision of an independent system operator, for fair, nondiscriminatory provision of transmission to all suppliers. Furthermore, through contracts for differences and direct access contracts, customers will have opportunities to curb the impact of price fluctuations of the Exchange or avoid them entirely.

f. Thin Markets

Parties commenting on previous proposals to create such a market also raised concerns that we refer to as *thin market* concerns. A thin market is a market that is not sufficiently broad to provide a price that reflects the true societal value of the relevant product in the relevant geographic market. NYMEX, ENRON, the Attorney General of California, the Energy Producers and Users Coalition (EPUC), and others have expressed doubts that the Power Exchange price would accurately reflect the true market value, and thus would promote anticompetitive activities.

Parties have identified an instance in which a thin market might be a problem in the single mandatory spot market scenario. This instance is related to proposals to require the spot market to take the output of certain generation resources, regardless of their cost-competitiveness, to meet contractual obligations or policy goals.[38] In this case there is a possibility that the quantities of market competitors' generation will be sufficiently small relative to the must-take resources that market-clearing prices will fail to reflect actual societal resource values.

g. Predatory Pricing

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[38] Resources that might be provided this treatment are QF contracts, nuclear generating facilities operating under settlement provisions, and long-term import energy contracts.

Predatory pricing is an illegal pricing strategy that a firm undertakes to drive current competitors out of the market and to prevent new entrants by selling a product below cost.[39] It is a short-term strategy firms undertake to meet their long-term goal of sustaining market power. Firms that already have market power have also used the threat of predatory pricing as a strong barrier to entry. Certain circumstances are necessary for a firm to engage in or threaten predatory pricing. In particular, a firm must have the ability to withstand the short-term losses and to absorb the increased demand stimulated by the low predatory price. Furthermore, the firm must be able to profit from the venture by eventually earning sustainable monopoly profits. This generally requires that the market have strong barriers to entry, such as prohibitively high initial capital or other investment costs. Several parties, including EPUC, have expressed concern that the utilities might be able to use predatory pricing or the threat of it to increase or maintain their market power.

We will be alert to specious allegations of predatory pricing made by unhappy rival firms to protect their own competitive interests. In many healthy competitive markets firms will temporarily price below average total cost for good reasons and with insignificant harm to the industry. These instances include low-priced introductory offers, expiring inventory sales, sales from firms exiting the industry, and incremental sales needed to reach minimum efficient scale. The duration of these activities, the concentration of the market, the competitive importance of the firm, and the reason for the pricing must be considered before we or other governmental industries should contemplate intervening in the market.

Mitigation: By the creation of an ISO, the strict limitations on recovery of operating costs for nonnuclear, nonhydroelectric units through the CTC, and our further consideration of utilities' applications or comments on divesting up to 50% of their fossil generation and separation into three subsidiaries, we are satisfied that we are taking adequate steps to curb this

[39] The practice is illegal under the Clayton Act of 1914.

form of market power abuse. Additionally, we retain our ability to react to particular instances of market power abuse through our complaint procedures, monitoring of the market structure we establish, and reforms that may become necessary as the market evolves.

h. Information

As a monopoly provider of integrated generation, transmission, and distribution services, the incumbent utility has access to considerable information about its customers, including individual load profiles and billing histories. In a competitive arena, access to such information is quite valuable for marketing purposes. Because this information is not automatically available to the utility's competitors, the incumbent utility has a major marketing advantage that could allow it to target and sign up preferred customers before its competitors can. The Framework Parties voice significant concern about this possibility.

Mitigation: We will require that customer specific information necessary for the distribution (accounting and billing) functions of the utility be made available on terms that are fair to all competitors in the generation sector. Because customer confidentiality concerns attach to this information, customer consent will be a prerequisite for all suppliers that obtain access. Separation of a separate distribution subsidiary would assist our efforts to make customer information available on equal terms and conditions; however, it is not essential. The implementation of this policy should be addressed by the Working Group.

Access to information about transmission will be largely resolved through the protocols of the ISO and FERC’s efforts to establish transmission information networks (call the RIN NOPR). All market participants will have the same access to information about the transmission system.

V. TRANSITION COSTS

Our investigations over the last several years have made it clear that California's electric rates are high. As we move to rely on competitive markets to supply power and to expand customer choices for power supplies, the Commission must confront and dispose of those costs that both keep rates high and act as an impediment to fair competition. We have found that many of today's high costs result from past regulatory promises made by the Commission regarding the timing of the recovery of depreciation and taxes, past requirements to diversify sources of power by signing long-term contracts that in hindsight have high costs, and the costs incurred by utilities (most notably those associated with QFs and nuclear power) that were reviewed and deemed reasonable when incurred.

Allowing more competition and customer choice in California's electric generation market means a utility may not be able to earn a price for its generation that covers these costs. Our objective continues to be the collection of transition costs in a manner that is competitively neutral, is fair to various classes of ratepayers and does not increase rates.

To achieve that objective, we will institute a nonbypassable charge, called the competition transition charge (CTC), for all customers who are retail customers on or after the date of this decision, whether they continue to take bundled service from their current utility or pursue other options. We recognize that this will require us to coordinate with FERC and may result in recommendations to the Legislature. We will fairly allocate the CTC to avoid cost shifting among classes by using current cost allocation principles. We will protect against rate increases by insuring that rates for customers taking bundled service are capped at the levels established by our January 1, 1996 revenue requirements.

To assure the continued financial integrity of the utilities, and give them an opportunity to be vital market participants in the restructured market following the transition, we will allow them to recover completely costs associated with contracts for power and prior regulatory commitments, called regulatory assets. We will continue to honor regulatory commitments regarding the recovery of nuclear power costs. For other generating plants, we commit to an accelerated recovery of the net book value of those undepreciated assets and other fixed obligations combined with a reduction in the return on those assets which make claims for transitional support.

In particular, we will reduce the imputed cost of capital on generation assets making claims to transitional support by setting the return on the percentage of the undepreciated asset financed by equity to a level of 10% below the long-term cost of debt. This reduced return reflects the reduced risk associated with these assets as we accelerate the return of their net book value through the CTC recovery. The 10% reduction may be eliminated by the utility divesting (spinning off or selling to an unaffiliated entity) at least 50% of its fossil generation. We will allow a 10-basis point increase in equity return for each 10% of fossil plants disposed of through sale or spinoff. Utilities may earn additional profits for fossil plants when operating costs (including capital costs not yet incurred) are below the Exchange clearing price.

We will also allow recovery of other costs we deem to be completely unavoidable. Finally, we recognize that the transition to expanded customer choice and competitive markets can produce hardships for employees who have dedicated their working lives to utility generation and we conclude that costs associated with retraining and early retirement have a claim for recovery as transition costs.

Our methods for valuing the transition costs will rely to the extent possible on market mechanisms and will seek to minimize the transition costs. We will complete the valuation of the assets for inclusion in the transition cost balancing account by 2003. After 2003 no further accumulation of transition costs will be allowed unless derived from existing generation contracts and related ongoing contractual payments that continue beyond that date. With this exception, we will complete the collection of the transition costs by 2005.[40]

The primary issues we address in this section are what are, and who should bear the costs of, utility facilities or contracts that are not completely recoverable in the market. If we progress to a competitive framework without addressing this issue specifically, the utilities will bear these costs by default. In unregulated industries, this is precisely what happens: the firm that owns an asset that cannot compete writes off the unrecovered investment in the asset. Many parties, particularly the representatives of customers, urge us to follow this model. The utilities, on the other hand, argue that because these costs were incurred in a regulated industry and in fulfillment of the responsibilities of a regulated firm, they should not be treated the same way as costs incurred by businesses in unregulated industries. We note for clarity that future potential transition costs (with few exceptions) are already embedded in utility rates today; transition costs would simply be identified in a different way than they are today and this change should neither create a new ratepayer cost nor result in a higher revenue requirement.

In this section we address these transition costs. First, we provide a brief background about the elements of transition costs. Second, we explain why these costs should not be allocated to the utilities by default. Next, we consider the arguments regarding recovery and proposals for sharing these costs among affected parties. Finally, we address the recovery mechanism for transition costs.

A. Overview

1. What are Transition Costs?

The definition of transition costs begins with a recognition that the competitive market will classify utility generation assets as either economic or uneconomic, in whole or in part (such

[40] We recognize that competitive forces will influence the utilities' business plans over the transition period. Utilities may complete collection earlier, particularly if they choose to forgo collection any transition costs that we are providing them with the opportunity to recover.

as at particular times of the day or year). In simple terms, a utility asset is uneconomic if its net book value[41] exceeds its market value, and an asset is economic if its market value exceeds its net book value. For a particular utility, its transition costs are the net above-market costs associated with its assets, both economic and uneconomic.

Transition costs will be quantified at two points. First, we will require the net book value of all utility generation plants to be measured against the market, a process we refer to as market valuation, within five years. Second, plants that continue to operate temporarily within the regulated framework may incur ongoing transition costs by selling their generation for a market price that is less than the cost of producing that power (including return of and return on investment).

Transition costs arise from several sources:

Generation Assets: A particular generation plant's primary contribution to transition costs will be determined when the plant undergoes market valuation. In addition to investment-related costs (the costs of construction and capital improvements and a return on the undepreciated costs), generation-related costs include unavoidable commitments directly related to generation, including nonplant physical assets and contracts for plant parts or services and for fuel or fuel transport. Generation plants may also reveal transition costs in their ongoing operations. Transition costs arise when a plant is unsuccessful in its bid to supply power through the Power Exchange,[42] because if it is unable to sell its power, it has no opportunity to recover its fixed investment costs. Even if a plant is successful in selling its generation, transition costs will also accrue if the market price is too low to allow recovery of the plant's fixed costs. We

[41] By "net book value," we mean the original cost recorded in the company's books for a particular asset less any accumulated depreciation and adjusted for deferred taxes, and any other asset or liability account which relates to the asset.

[42] Certain nuclear facilities and plants that have undergone market valuation will operate under different conditions, as discussed in the market structure section and below.

will allow in transition cost 100% of the asset's net book value and any fixed obligation directly related to the asset.

Nuclear Power Plant Settlements: The Diablo Canyon settlement obligates ratepayers to pay a specified cents-per-kilowatt-hour (kWh) price for all energy produced by this plant. To honor this settlement, electricity from this plant will be taken by the grid whenever the energy is produced. To the extent settlement prices are above the prices in the market, as revealed by the Power Exchange, this plant will be uneconomic.

Power Purchase Contracts: Utilities currently purchase power from QFs and from wholesale suppliers. Certain power purchase agreements between utilities and QFs require power to be taken by the utility at specified prices whenever the power is produced, with certain exceptions. As with the Diablo settlement, QF contract prices may be above the revealed market prices, and thus the contract will be uneconomic. Similarly, prices under utilities' contracts with wholesale providers may be higher or lower than the market price. These contracts may either be uneconomic, increasing transition costs, or economic and available to offset other uneconomic costs.

Regulatory Obligations: These costs are primarily related to various deferred costs (including deferred tax assets which are unrecovered, relating to the generating asset only) and outstanding balancing account balances the utility has accrued under the current regulatory framework. These costs have already been approved for recovery and are reflected in current rates as part of utility revenue requirements.

2. Minimizing Transition Costs

a. Offsets

We arrive at each utility's net above-market costs after offsetting the benefits associated with economic assets against the excess costs of uneconomic assets. This netting of excess costs and benefits fairly reduces the overall level of the utility's transition costs. This netting of economic and uneconomic assets is also a partial way of compensating ratepayers for the loss of continued dedication to public use of economic assets. Under the old regulatory system, ratepayers would have a claim to the power produced by the utility's generating units, even after a particular plant was fully depreciated. For economic plants, that continued use could provide considerable benefit to ratepayers, and ratepayers deserve compensation for the loss of that continued use. Using the excess value of economic plants to reduce total transition costs is one convenient and accurate way to provide that compensation. Offsetting uneconomic assets with economic assets is fair in another sense. Under the existing regulatory framework, ratepayers pay a price for electricity derived from the utility's overall revenue requirement. The generation-related portion of that revenue requirement is based on the total reasonable operating and capital costs associated with the utility's mix of generating assets. The rate for electricity is thus an average reflecting the costs of both low-cost (economic) and high-cost (uneconomic) assets. It would be obviously unfair if, as part of our restructuring, we were to require customers to pick up the costs of high-cost generation without at the same time accounting for the benefits of low-cost generation.

b. Deferred Taxes

The calculation of transition costs should also account for deferred taxes. These deferred taxes represent both payments already made by the ratepayers (deferred tax liabilities) and deferred tax receivables yet to be paid by the ratepayers (deferred tax assets). The deferred tax liabilities should reduce the generating asset net book value included in the transition costs. The deferred tax receivable relating to the generating assets should increase the net book value included in the transition costs.

The deferred tax receivable from ratepayers resulted from timing differences between the "book" and "tax" methods of accounting that affect all generating plants that had been subject to depreciation before 1981. The tax benefits of these differences were flowed-through to the ratepayers in lower rates and now must be included in transition costs for those generating plants subject to transition cost recovery.

B. Should Utilities Recover Transition Costs?

Under the current regulatory structure, we have granted utilities monopoly franchises to provide electricity to the consumers in their service territories, and we have required utilities to provide reliable service on a nondiscriminatory basis to all customers within their territories who requested service. In fulfillment of these responsibilities, utilities developed a portfolio of generation assets by investing in power plants and entering into purchase agreements on the understanding, the utilities contend, that reasonable costs would be recovered in rates. They also assumed various other responsibilities related to being monopoly providers of electric services and responded to specific regulatory or legislative mandates and policies.

Utilities argue that these investments were found prudent at the time they were made and therefore they should be entitled to full recovery. The parties to the MOU agreed to the principle that:

> as the industry transitions to a new competitive electric market structure, [the utility] should fully recover its prudently incurred past investments and obligations made to fulfill its historical obligation to serve.[43]

We conclude that the utilities should be allowed to recover appropriate transition costs. Longstanding regulatory policies, past Commission decisions, and ongoing regulatory effects persuade us of the need, during the transition to full competition, for a process to account for the lingering effects of today's market structure. Thus, we must develop a method to minimize the effects of the high-cost elements in the competitive market structure, while we close the books on past practices. We will identify utility capital investments and contractual obligations, quantify their costs as accurately as possible, and separately identify a charge to recover these costs. Our goal is to get through this transition period as quickly as possible so that full competition can begin with minimal market distortions.

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[43] MOU, p. 10. In their filed comments, both PG&E and SDG&E agreed with this principle.

We also emphasize, as we mentioned in Section II, that maintaining the financial integrity of the utilities is an important goal of this proceeding, and a goal we will pursue in making the transition to a more competitive marketplace. Investors' uncertainty about the recovery of transition costs may harm the utility's ability to raise capital and may result in a higher cost of debt. If we do not provide for adequate transition cost recovery, the move to competition may threaten the utilities' financial stability. If the utilities were required to write off the entire amount of above-market levels of investments, they could face a financial disruption that might lead to lower system reliability and inefficient operation.

C. Transition Cost Recovery for Remaining Net Investment Should be at a Reduced Rate of Return

Throughout this proceeding numerous parties provided arguments in support of some level of transition cost sharing between ratepayers and shareholders. Most parties believe that the Commission is not obligated to guarantee full recovery of the costs the utilities have incurred to construct uneconomic assets. In comments filed in response to the MOU, two sets of parties state these views in different ways:

> The maximum percentage of "stranded costs" which are eligible for recovery from customers by the utility through CTC must be less than 100%. Allocating stranded costs in this manner is consistent with regulatory precedent, and will provide the utilities with clear and strong incentives to mitigate the amount of costs to be treated as "stranded."[44]

> Shareholders should bear a fair share of the burden of stranded costs. Fair allocation should recognize that the problems of today's utility are neither entirely of their own making nor entirely beyond their control and responsibility. Fair allocation should recognize that utility shareholders have been compensated for business and competitive risks for many years.[45]

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[44] Framework, p. 5.

[45] Customer statement of principles on electric restructuring response to the Memorandum of Understanding, filed October 2, 1995, by the Association of California Water

We derive two principles from the discussion of how to allocate transition costs.

The first is that ratepayers should benefit, at least to some degree, from our treatment of transition costs. Some of our main themes in this restructuring effort have been to give customers choice and to introduce competition with the goal of reducing rates. It would be inappropriate to require ratepayers to bear the same costs they would have borne in the absence of this reform effort, especially when those costs tend, in the new competitive framework, to distort market prices and signals.

The second is that shareholders should recover somewhat lower revenues as transition costs than they would under cost-of-service regulation. Under traditional regulation, utilities would have the opportunity to recover the amount of the original construction cost of a plant over the plant's expected useful life, plus a reasonable return tied to risk, as long as the plant remained used and useful for public utility purposes. Allowing this level of recovery in the transition to competition produces several undesirable effects. Of greatest concern is that the assurance of full recovery gives the utility no incentive to minimize transition costs. This is counter to our goal of keeping transition costs as low as possible, but it has even worse implications. If the utility is indifferent to the level of transition costs, it would in turn have an incentive to bid low in offering its generation assets' output to buyers in the Power Exchange, with the foreseeable effects of depressing the market-clearing price, squeezing the profit margins of competitors, and further increasing transition costs.

These two principles--benefits for ratepayers and proper incentives for utilities--can be accommodated in a recovery mechanism that reduces the return on investment-related transition

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Agencies, Agricultural Energy Consumers Association, California Department of General Services (DGS), California Farm Bureau Federation, California Hotel and Motel Association, California Industrial Users, California League of Food Processors, California Restaurant Association, California Retailers Association, DRA, and School Project for Utility Rate Reduction.

costs. Recovery of transition costs imposes a significantly lower risk for recovery of these costs because, once an asset is market-valued, the utilities will not be subject to the risk that the plants will be found no longer to be used and useful. Thus, if we apply a reduced rate of return to these transition costs, we will appropriately reflect the lower degree of risk the utilities face.

This approach also provides benefits to ratepayers in two ways: First, consistent with the lower risk involved, it reduces the transition cost revenues associated with generation plants from the levels that ratepayers would otherwise pay in rates under cost-of-service ratemaking. Second, reduced revenues will also reduce taxes that would otherwise be reflected in rates.

We note that we are not required to guarantee full transition cost recovery. We are required only to design a rate structure the total impact of which provides the utilities with the opportunity to earn a fair return on their investment. (Duquesne Light Co. V. Barasch (1988) 488 U.S. 299.) We are allowing the utilities the opportunity to recover generation plant-based transition costs and providing an appropriate risk-based rate of return until those costs are recovered. There is a strong likelihood that utilities will be able to recover all transition costs, but in the future, competitive pressures may lead utility managers to discount the transition cost rate element or to forgo a portion of recovery, in the exercise of their business judgment.

We propose to apply a reduced rate of return to investment-related transition costs. As modified and if accepted, the settlement in the SCE general rate case (A.93-12-025/I.94-02-002) provides that the net book value of SONGS should be recovered with a rate of return for the debt component equal to the utility's embedded cost of debt and a rate of return reduced by 10% for the equity component.

In the past, this Commission has considered at least two cases in which generation units reached the end of their usefulness (i.e., were no longer used and useful) before sunk costs had been fully recovered: the Humboldt Bay Unit III nuclear power plant and the San Onofre Nuclear Generating Station Unit I (SONGS I). In both cases the Commission provided shareholders less than full recovery of the combination of sunk costs and rate of return at the weighted cost of capital. In D.92-08-036 (45 CPUC 2d 276), the Commission adopted a settlement which allowed a 48-month amortization of remaining net investment in SONGS I. After the unit was shut down, remaining unamortized investment was allowed to earn a rate of return at the authorized embedded cost of debt. In D.83-05-051 (11 CPUC 2d 538), regarding the unfinished Humboldt Bay Unit III, the Commission excluded capital expenditures plus unamortized nuclear fuel from rate base and terminated further accumulation of Allowance for Funds Used During Construction. The Commission eventually allowed PG&E to recover all capital costs at a lower rate of return.

We expect that some utility plants will no longer be used and useful in the future restructured energy marketplace. Allowing recovery of remaining net investment associated with the SONGS I plant at the embedded cost of debt was reasonable at the time, given the then-current regulatory structure. However, today's decision decreases the risk associated with recovery of remaining net investment (now part of transition costs), due to the imposition of a nonbypassable charge on distribution customers (as described in greater detail below) which decreases utility business risk. We will adopt 90% of the embedded cost of debt as a reasonable rate of return on the equity portion of the net book value to reflect the reduced risk. We will set the return on the debt portion of net book value at the embedded cost of debt.

This mechanism will provide utility management with an incentive to minimize the level of transition costs, and as a result to reduce rates. At the same time, allowing this lower rate of return on the equity portion is appropriate in light of the reduced risk and will not adversely impact the utility's financial stability.

D. Calculation of Transition Costs

We have previously identified three primary sources of transition costs: uneconomic utility generating assets, further subdivided into nuclear and other, nonnuclear facilities; existing power purchase obligations, consisting of QF contracts and wholesale contracts; and regulatory obligations.

Parties have suggested ways of calculating transition costs that may be characterized as either administrative or market-based. Under an administrative approach, we would attempt in our proceedings to assemble reliable information that would help us calculate an estimate of transition costs. Market-based approaches derive an estimated value from observation of the collective actions of buyers and sellers.

We concur with most of the parties' view that a market-based approach to calculating transition costs associated with utility assets will produce superior results to an administrative approach. An administrative approach to valuing utility assets introduces forecasting error and necessarily relies on numerous assumptions that would likely be contested. For example, this approach requires long-term forecasts of market prices and assumptions about existing and future QF obligations, discount rates, capacity factors, and other variables. The estimates of overall transition costs presented by the utilities and other parties, using their versions of an administrative approach, ranged from negative $8 billion to $32 billion.[46] To avoid the potential for forecast errors of this magnitude in the transition cost calculation, market-based, observational methods for quantifying transition costs for the uneconomic portion of the utility's generation assets should be employed as much as possible. However, we will use an appropriate administrative approach as necessary to calculate the level of transition costs during the period prior to market valuation of the assets.

In the following pages we discuss in detail our approaches to calculating transition costs. This calculation will be made in connection with two occurrences. First, when an individual asset undergoes market valuation, using one of the approaches described below, we will compare the resulting market value with the asset's undepreciated book value. Second, we will make annual calculations of other types of transition costs.

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[46] We do not adopt or endorse any of these estimates, but this wide range of estimated costs illustrates our reservations about the administrative approach. Estimates vary significantly due to assumptions used in the calculations.

We propose to establish a transition cost account for each utility. This account will be credited and debited annually and adjusted after each utility generation asset receives its market valuation (sale or spinoff). We will review each asset's market valuation and the associated adjustment to the transition cost account in conjunction with the utility's application for a finding that the asset is no longer "necessary or useful" for the provision of utility service (§ 851) and thus may be used for other purposes. This account will also record transition costs resulting from the operation of nuclear power plants and power purchases under existing wholesale and QF contracts. Transition costs for these resources will be calculated annually over the terms of the settlements and contracts or until the authorized transition cost recovery has been completed. Transition costs associated with regulatory obligations will also be included in this account as authorized by the Commission. This account will also include reasonable costs of early retirement or retraining programs that seek to ease the labor force disruptions associated with this transition. As we have discussed, interest on the balance in the transition cost account related to recovery of the uneconomic portion of generating assets will reflect the lower rate of return previously discussed. Interest on other transition costs recorded in the account, such as the costs of purchased power and certain regulatory assets, should reflect a rate appropriate to the term over which these accounts are financed, but no higher than the long-term cost of debt.[47]

There are three primary ways to calculate transition costs. The first approach is to calculate transition costs on an ongoing basis by comparing the authorized revenues associated with the plant to the actual revenues earned in the market. The second approach will be used when the utility chooses to divest an asset. Transition costs will be calculated by comparing the asset's net book value to the market value as measured by the sale price, or the stock market

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[47] Our decision to have different returns for the debt and equity portions of investment-related transition costs and for other types of transition costs will require the establishment of subaccounts within the transition cost account for the imputed debt and equity portions of the net book value of each generating asset.

value of shares issued to effect a spinoff. The third approach will be used if the utility chooses to retain the asset, in which case transition costs will be calculated by comparing the market value established through an appraisal to the net book value.

1. Ongoing Transition Cost Calculation

Prior to market valuation of the utility generation assets, transition costs will be calculated annually. This calculation will include the transition costs associated with the operation of the utilities' generation assets, contractual obligations, and regulatory obligations.

a. Nuclear Generation Facilities

California currently has two operating nuclear generating stations. Diablo Canyon is owned and operated by PG&E. SONGS is owned by SCE and SDG&E; SCE owns approximately 80% and is responsible for its operation. SCE also owns approximately 16% of the Palo Verde Nuclear Generating Station in Arizona.

(1) San Onofre Nuclear Generation Station

The method for calculating transition costs for SONGS will depend on the outcome of our consideration of a settlement presented in SCE’s pending general rate case, A.93-12-025. The proposed settlement would provide incentive ratemaking for SONGS. In the MOU, SCE indicated that it would petition to modify our decision approving the settlement proposed in the general rate case to incorporate the alterations related to plant shut-down incorporated in the MOU. If we approve the settlement, we will consider SCE’s requested modification when it is presented, and today’s decision does not prejudge that issue.

(2) Diablo Canyon

Under our proposal, the ISO will schedule power from Diablo Canyon on a must-take basis. Ongoing transition costs will be calculated as that portion of the settlement payments in excess of market value, as determined by the Power Exchange price. This calculation will be performed over the term of the settlement or until transition cost recovery is completed. These costs will be entered in the transition cost account as part of our annual review.

We are concerned that the disparate ratemaking treatment of Diablo Canyon and SONGS may create inequities for ratepayers in different parts of the state. We will order PG&E to file an application within 100 days after the date of this decision with its proposal for ratemaking treatment for the Diablo Canyon facility that would price its output at market rates by 2003 and complete recovery by 2005. The application must also be consistent with the principles for recovery stated at the beginning of this section, including no rate increases above January 1, 1996 levels, and must include at least one alternative similar to the SONGS settlement.

(3) Palo Verde

In the MOU, SCE states its intention to file a proposal for a new rate mechanism for Palo Verde. We direct Edison to file this application within 100 days and to include a proposal for ratemaking treatment comparable to the ratemaking treatment ultimately adopted for SONGS for rates effective on or before 1997. Transition costs for Palo Verde will be calculated and recovered the same way as all other generation assets that remain under the utility's ownership unless and until we approve SCE's application or otherwise change our method of calculation.

b. Contractual Obligations

(1) QF Contracts

Under our proposal, existing QF contracts will be honored by the remaining electric distribution utility. The utility will retain its obligation to administer its QF contracts in the best interests of its customers and in a manner that maximizes systemwide benefits and minimizes transition cost accrual. The dispatch of some QFs is governed by contractual provisions, and QFs with firm contracts (Standard Offer No. 2 and Interim Standard Offer No. 4) are subject to certain performance requirements. These contractual provisions give the purchasing utility a limited ability to influence the scheduling of QF energy deliveries.

Transition costs will be calculated by comparing the contract price with the market-clearing price established in the Power Exchange for each time increment when the QF delivers power. We intend to set short-run avoided cost energy payments at the Exchange's clearing price as soon as we are confident the Exchange is functioning properly. Therefore, CTC that accumulates after 1998 will flow primarily from the capacity payments and fixed energy payments.

We recognize that both and utilities may have incentives to renegotiate their contracts.[48] Utilities will need to minimize costs to remain competitive and QFs may have an incentive to renegotiate as a result of our consideration of ways to revise our short-run avoided cost methodology for QF energy payments to reflect the prices established in the Power Exchange. The May proposals recommended establishing monetary incentives to facilitate contract renegotiation. Most parties commenting on this proposal support incentives as a means of reducing transition costs and releasing QFs from contract obligations to allow them to compete in the generation market, although few commented on the specific recommendations for either a 20% or 50% sharing of cost savings between ratepayers and shareholders. Rather, the comments stress the importance of voluntary, nondiscriminatory negotiations on this issue. The MOU recommends standard options and preapproved guidelines for voluntary negotiations.[49] Similarly, the California Cogeneration Council (CCC) recommends that we establish generic options for the "buy down" of QF contracts.

We endorse an approach that involves both a monetary incentive to shareholders and conditions which foster voluntary, nondiscriminatory negotiations. We will allow shareholders to retain 10% of the net ratepayer benefits resulting from a renegotiation, which will be reflected by an adjustment to the transition cost total. Modification of QF contracts will follow our

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[48] Our policy of establishing a requirement for purchases of generation powered by renewable sources and allowing trading in renewable credits, discussed in Section VI, will introduce an incentive for renewable QFs to renegotiate their contracts.

[49] Sponsoring parties to the MOU indicate that they will develop details for renegotiations and standard options by the end of 1995.

existing principles[50] that the modifications are voluntary on the part of the QF and should provide ratepayer benefits relative to the most probable stream of payments for that QF without the modification, and should benefit from the flexibility that non-standard, arm's length negotiations have previously revealed. We will continue to preapprove modifications. We also look forward to the recommendations of the sponsoring parties to the MOU.

(2) Other Wholesale Power Purchase Agreements

As with QF contracts, other existing wholesale power purchase agreements will continue to be honored by the utility and should be administered in a manner which maximizes systemwide benefits and minimizes transition costs. To the extent that the purchasing utility can influence the amount and timing of power deliveries, we will expect and require the utility to fully exercise its ability to do so for the benefit of its ratepayers. We also encourage the utilities to renegotiate these contracts whenever possible and appropriate in order to reduce transition costs. Calculation of transition costs will occur in the same manner as for QF contracts; that is, contract costs will be compared with market value.

c. Regulatory Obligations

The transition costs that arise from regulatory obligations are related to various deferred costs and outstanding balancing account balances the utility has accrued under cost-of-service regulation. In most cases, we have already approved recovery of these costs, and they are reflected in outstanding balances of balancing accounts. Examples of these types of costs include deferred operating expenses, deferred taxes, unamortized loss from sale of assets, unamortized debt expense, costs associated with issuing or reacquiring debt, and nuclear decommissioning expenses. We also will allow reasonable employee costs incurred as part of the transition to

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[50] We previously considered guidelines on negotiations to restructure some QFs' contracts to avoid some of the consequences of the end of the fixed-priced energy period under the contract. (D.94-05-018. See D.93-01-048, 47 CPUC 2d 772.)

competition, including early retirement and retraining costs, to be recovered through the transition cost account.

We plan to evaluate specific account balances and determine the amounts that will be included as part of transition costs during the implementation phase of this rulemaking, but these amounts should relate only to the generation assets affected by this restructuring. Once we identify and approve these costs for transition cost treatment, they will be credited or debited to the transition cost account and recovered in the same manner as other transition costs.

The cost of future decommissioning of nuclear facilities requires special consideration. These costs require a significant amount of capital, and we will ensure that adequate funds continue to be collected to cover the costs of nuclear decommissioning. Therefore, we will continue to oversee and monitor the existing trust funds to ensure that they are adequately maintained. In the event that a nuclear plant changes ownership, the existing trust fund balances would follow the asset to the new owner. The new owner would be obliged to comply with Nuclear Regulatory Commission regulations to continue funding for decommissioning. If the distribution company retains ownership of the nuclear facilities after market valuation, costs for the decommissioning trust fund will be added into the transition cost account.

d. All Other Generating Assets

(1) <u>Fossil fueled units</u>

Prior to market valuation, utilities will be able to recover 100% of their fossil fueled units' undepreciated, book value (existing rate base) through the CTC. Generation plant clearly includes the facility, but may also include other long-term obligations used solely for generation, so that the undepreciated net book value will be fully recovered by the end of 2005. We will allow the embedded cost of debt for the debt portion of the utility's capital structure associated with these plants. The return for the remaining share (equity) will be 90% of the embedded cost of debt.

All other costs of running these units, including capital costs not yet incurred, will be subject to recovery through the prices received from the Exchange, with one limited exception. For those units that are primarily needed for reactive power/voltage control, if the costs of running these units (including capital costs not yet incurred) exceed the Exchange clearing price, utilities may seek partial recovery of operating costs up to the year 2003, subject to performance-based ratemaking, until or unless market based prices are established for reactive power/voltage control by the FERC. Further, if no recovery for reactive power/voltage control is sought, and the Exchange clearing price exceeds the costs of running these units (including capital costs not yet incurred), utilities may retain profits providing up to 150 basis points above their authorized return for distribution rate base. Any further profits will be used to reduce CTC.

(2) Other Units--Hydroelectric and Geothermal

Each distribution utility will retain ownership of its hydroelectric and geothermal generating assets. These assets will remain subject to rate-of-return regulation and will continue to provide their electric output to the distribution utility through the Power Exchange. Any surplus revenues from these sales (above the revenue requirement associated with these units) will be credited toward reducing transition costs. Each utility will be encouraged to submit an appropriate generation-related PBR for these assets. The Commission may consider either the sale or spinoff of these assets at some future date and the resulting gain would also reduce transition costs.

2. Transition Cost Determination and Market Valuation for Sale or Spinoff of Assets

If the utility chooses to sell an asset, we will require the utility to make its intent widely known, so that all potentially interested buyers are notified of the proposed sale. Our purpose in requiring this notice is to ensure that the highest possible price is obtained for the asset. We are for similar reasons concerned that negotiations are conducted at arm’s length and that the resulting sale price is generally consistent with other market information. Once these conditions are satisfied, we would accept the sale price as a reasonable reflection of market value. Transition costs would be calculated by comparing the asset's net book value with the sale price.

The MOU recommended that the utility should be able to bid when its own asset is put up for sale. Subject to the concerns stated in the preceding paragraph, it may be possible for the utility to participate in the sale, and if it is the highest bidder, it may retain the asset, perhaps under the ownership of an affiliate. The utility should not, however, have an automatic right to match the winning bid if the winning bid does not exceed the utility's bid by some margin, as called for in the MOU, because the existence of reserved right will tend to depress bidding and increase transaction costs. If the utility wants such a right, it should pay in advance an appropriate price reflecting the value of this right. Any such payment will be added to the winning bid to increase the market value of the asset.

If the utility chooses to spin off its assets, market valuation for the assets will be determined by multiplying the stock price of the new company owning the generation asset during some reasonable period after the spinoff by the number of outstanding shares. Transition costs will be equal to the difference between the net book value of the generation asset and the market value determined after a reasonable period of time.

The market value of the spun-off generation asset can be directly identified by observing changes in the stock prices of the spun-off and original companies.[51] However, because of stock price fluctuations, it is appropriate to observe the stock prices over a period of time. A clearer sense of the market value might be gained by observing the average stock prices over, for example, the first 30 or 100 trading days, or even longer, after the announcement or completion of the spinoff. Transition costs from market valued assets will be entered into the transition cost

[51] If the spun-off company is new, it may be hard to determine market value from stock price unless generation assets are the only assets of the new company. We might need to observe changes in the price of the original company's shares, which will reflect the market value of the loss of the asset, in the period following the public announcement of the planned spinoff.

account once they have been reviewed and approved by the Commission in conjunction with the utility’s application under § 851.

If a plant is shut down because the utility believes (and the Commission agrees) the plant has little or no market value in the new restructured electricity market (and thus is no longer "used and useful"), transition costs associated with these assets will be subject to review under § 455.5. In many cases, transition costs will be equal to the difference between the net book value and the net salvage value of that generation asset. As we have discussed, the salvage value of a generation asset would consider the value of the site for potential repowering of the unit or for new generation facilities.

3. Appraisal Valuation

For assets that remain under the utility's ownership or that are handled through an accounting separation, we will use an appraisal valuation to determine transition costs. Market valuation of assets through an appraisal approach will provide results superior to an administrative approach because the appraisal approach relies on independent industry experts rather than experts hired to support each party’s position, as is common in regulatory proceedings. However, the MOU's recommendation to have the IOUs submit a list of qualified appraisers to perform the market valuation would minimize this advantage. We generally support this approach, but we think a preferable process is for all affected parties--primarily the utilities and ratepayer representatives--to develop an agreed-on list of impartial and qualified appraisers, from which we would select no more than three, as the MOU provides. This appraisal process should only occur after the Exchange has operated a reasonable time to allow for greater Exchange price certainty.

Under the MOU proposal, the utility would have the right to accept or reject the appraised valuation, and if the utility chose to reject the appraisal, the utility would have to spin-off or sell the asset. This recommendation of the MOU must be modified to allow for the Commission’s review of the appraisal. If the utility accepts the appraisal, it must still apply for the

Commission's determination that the asset is no longer "necessary and useful" for public purposes under § 851. That application will also create a forum for our review of the appraisal. If the utility chooses to reject the appraisal and to spin off or sell the generating asset, the spinoff or sale will also require a § 851 application, which will provide a forum for us to determine the amount of transition cost associated with the transaction. This oversight allows us to ensure that the utility does not improperly reject an appraisal and then receive a lower sale price, thus increasing the level of transition costs.

E. The Competition Transition Charge (CTC)

1. Jurisdiction to Collect Transition Costs

In the MegaNOPR, the FERC reaffirms the view expressed in its original NOPR on stranded cost recovery that utilities are entitled to recovery of legitimate and verifiable stranded costs from increased competition in and entry to the wholesale market. (The FERC's "stranded costs" are similar to the transition costs associated with uneconomic assets.) The FERC determined to leave retail transition cost recovery to the states.[52] The FERC pointed out that states have mechanisms to recover retail transition costs, including the ability to impose charges on facilities or services used in local distribution.[53]

We agree that recovery of retail transition costs should be subject to state jurisdiction. Jurisdiction over retail transition costs is well-defined under the Federal Power Act and lies exclusively with state authorities. The FERC has no jurisdiction over costs incurred at the state level to serve retail customers, regardless of whether or not those costs are rendered uneconomic

[52] The FERC has distinguished between wholesale and retail stranded costs for jurisdictional purposes. The FERC asserted exclusive jurisdiction over allowing utilities to recover costs incurred to serve wholesale customers which are then stranded due to the wholesale customer's ability to take advantage of open transmission to obtain access to another wholesale supplier.

[53] MegaNOPR, mimeo. at 250.

by our new market structure. State jurisdiction over retail transition costs extends, in our view, to costs stranded by retail customers converting to wholesale status, and we will exercise our jurisdiction to recover those costs, either through exit fees or through some other mechanism. It may be desirable to have state legislation to enhance our authority over recovery of retail transition costs from customers who change their status from retail to wholesale.

2. Collection of the CTC

We will authorize utilities to recover their retail transition costs through an end-user surcharge that will apply to sales to both retail procurement and utility customers on a utility service territory basis. The utilities should ask the FERC to confirm that delivery services to both retail procurement and utility customers contain some elements of local distribution. In addition, we adopt the MOU's recommendation that direct access customers must, as a condition of the utility's retail distribution tariff, sign an agreement to pay their share of transition costs and thereby waive any jurisdictional objection they might otherwise raise in any forum. Allowing utilities to recover legitimate transition costs is an essential element of the new market structure and a precondition to direct access.

To that end, we also will require utilities to modify the Preliminary Statement of their tariffs to provide all current and new customers with notice of our intent to authorize collection of retail transition costs. Whether further customer notice, such as a bill insert, is required is an implementation issue to be developed by utilities and other interested parties through the Working Group. Issues surrounding enforcement and collection of the CTC for departing customers will also be referred to the Working Group to develop consensus recommendations if possible.

The CTC will be a percentage surcharge on the dollar amount of each bill of each customer, including those served under contracts with nonutility suppliers, of the distribution utility. The surcharge will be designed to amortize the balance in the transition cost account over a reasonable period (not to exceed 2005 for generating assets), and the level of the surcharge will be adjusted annually to reflect changing account balances, amortized over the remaining years to 2005.

3.Allocation of the Competition Transition Charge

Transition costs will be allocated to all customer classes using an equal percentage of marginal cost (EPMC) methodology, unless specific circumstances justify a different approach. Marginal cost pricing for electric services using the EPMC methodology is well established, and using this approach for the allocation of transition costs ensures a fair allocation among all customer classes and prevents inter- and intraclass cost-shifting. Using this approach also preserves the cost allocation that we have previously reviewed and approved.

4. Period for Collection of the CTC

One of the goals of this proceeding is to lower the price consumers pay for electricity. Recovery of transition costs frustrates this goal because it is possible that the surcharge will exceed price decreases in a given year, resulting in higher electricity-related costs for consumers. To avoid this result, we will cap transition cost recovery so that the price for electricity does not rise, on a kWh basis, above current rate levels in effect as of January 1, 1996 without adjustment for inflation. This cap may mean that transition cost recovery will extend over a period of several years. As previously discussed, transition costs will be calculated on ongoing basis and will be entered into a transition cost account.

The total level of transition cost compensation each year will depend on the amount in this account and the level of the rate cap. However, our goal is to complete the recovery of transition costs in the shortest possible amount of time, consistent with our goal of not increasing electricity prices. Therefore, we will complete the recovery of transition costs by 2005, except for ongoing contractual payments related to contractual obligations entered into before January 1, 1996.

F. Transition Cost Filings

The utilities are authorized to establish a transition cost balancing account. Each utility will have an annual proceeding to address adjustments to the account. In these proceedings utilities will also show that our principles for CTC collection are reasonably expected to be met: that CTC collection will be complete by 2005 and that rates will be at or below 1996 levels. The first applications should be filed by September 1, 1996 to set the CTC for the beginning of transition cost collection when the new market structure begins, not later than January 1, 1998.

Interest on the various components of the account will be calculated as we have discussed in this section. Transition costs associated with contractual obligations and assets that have not undergone market valuation will be recorded in this account on an ongoing basis and will be subject to review in our annual proceeding. Upon market valuation of an asset, utilities shall file a § 851 application to initiate review of the market price, transfer of the asset, and removal of the costs from the PBR benchmark.

VI. PUBLIC PURPOSE PROGRAMS

California's electric utilities have a long history of participating in activities that assist many California citizens. These activities include rate discounts for low- income individuals, programs to improve economic development, efforts like the Women, Minority, and Disabled Veteran-owned Business Enterprise program (WMDVBE) to improve the procurement practices of regulated utilities, energy efficiency efforts, promotion of resource diversity and development of renewable resources, and the development of statewide guidelines for utility research, development and demonstration (RD&D) efforts. Many of these programs are provided because of Legislative mandate. These programs exceed the basic requirement that a utility provide safe, reliable and reasonably priced electric services, and reflect a recognition that the electric utilities are fundamental to the fabric of our society, deliver a necessary service, and can assist in the achievement of valuable social goals. However, as recognized in the May proposals, the continued reliance on utilities to achieve social goals may put the utility at a disadvantage in the move toward a more market-based, customer-oriented electric services industry. Subjecting utilities to the cost of programs that their competitors do not bear may not be a sustainable strategy.

The need for activities performed in the public interest will continue in the future, but the role of electric utilities as the providers of these services is less clear. Given the Legislature's role in creating these programs, we do not view it appropriate to alter them significantly without Legislative guidance. We therefore will maintain the status quo for the time being, but expect to work closely with the Legislature and stakeholders as we implement this policy decision to determine where changes might be appropriate.

For the interim, we will propose the establishment of a target level of generation from renewable resources. This target will be backed by a meaningful penalty for noncompliance. We propose a nonbypassable surcharge, the Public Goods Charge (PGC), on retail sales to fund public goods RD&D and energy efficiency activities, and we will support legislation authorizing a separate surcharge to collect funding for low-income assistance programs. We provide initial guidance on these issues, but recognize the need for additional information on implementation specifics. Toward this end, in Section VIII we describe how we anticipate implementing this decision.

Many other public purpose programs continue to be a responsibility of the regulated utility, and therefore should continue to be collected as part of regulated rates. We indicate whether line-item listing of charges for specific programs on customer bills appears warranted.

The development of our thinking in this area was greatly assisted by the independent Working Group, which we asked interested parties to form to develop implementation options to carry out social, economic, and environmental policy goals. The Working Group submitted its report on February 22, 1995.[54]

A. Renewable Resources

Electric generation in California utilizes a very diverse set of resources. The renewable resources currently in operation either are owned by utilities or sell to utilities under QF contracts. The present mix of renewables on the system has been driven by resource diversity interests on the part of utilities and the Commission's QF policy, which encouraged the growth of independent power production during the 1980s.[55] The Commission's recent policy of encouraging resource diversity through the development of new renewable resources is derived from §§ 701.1 and 701.3. This policy has been applied only to new resource procurement implemented through the Biennial Resource Plan Update (BRPU), which has not yet led to utility investment in additional renewables. Thus, the renewables that are on line today are the result of the Commission's QF policies and utility practices in place prior to the BRPU.

[54] Deleted

[55] Many QF contracts were structured to allow high capital cost renewables to obtain financing.

We are committed to establishing restructuring policies which maintain California's resource diversity for existing resources as well as encourage development of new renewable resources. The May proposals suggested two ways that these goals might be accomplished: 1) establishing a tradeable renewable target (assigned to either the buyer or seller) or 2) setting minimum diversity targets for the pool. The May proposals did not identify additional funding mechanisms to assist in meeting these targets.

In comments on the May proposals, many parties conceptually supported the recommended renewables target, including CEERT, CLECA, EDF, AWEA, Los Angeles Department of Water and Power (LADWP), FloWind, and NRDC. The CEC and PG&E stated that today's electricity system is sufficiently diverse in the near term and no further Commission action is needed. DRA supported this position, if the utility divests its generation plants. EPUC opposes mandating the type of resources used to meet electric demand. SDG&E supports establishing a statewide Environmental and Clean Energy Security Fund to finance renewable resources and fuel diversity, based on a user fee on electricity consumption, instead of the renewables target. Sierra Pacific prefers direct taxes.

Other parties commented that specific funding needs to be in place to stimulate long-term development of new renewable resources because of the high initial costs of these resources. EDF suggested funds could be implemented through a production credit to new renewable production (collected through a surcharge of 0.6% on utility revenues), distributed through a competitive process. CLECA supported this "auctioned renewable credit" approach. This process could be implemented by the Commission or some other entity. SCE advocated a legislatively determined subsidy for incremental renewable production, funded through a surcharge. Others recommended establishing two separate pool prices, one for renewables, one for all other resources, in order to achieve the renewable goals (see comments of AWEA and LADWP). The CEC stated that the Commission's endorsement of a specific long-term strategy on resource diversity is premature.

The MOU indicates support during the transition to full competition for some level of funding for renewable resources (consistent with the statutes) within a cap of 3.3% on utility revenue.[56] The Framework Parties addressed the appropriate level of a renewables target, and recommended providing funds to stimulate new development under any new market structure but did not identify a specific funding level. In comments on the MOU, DRA suggested that funding for new renewables development be limited to $75 million of the revenues collected under a broader public purpose surcharge.

The suggestions by the parties are not inconsistent with our recommended policy direction of establishing a minimum renewables requirement under either direct access or a pool. The parties' suggestions primarily concern additional resource procurement or implementation strategies. A policy of developing renewables targets which meet or exceed current or historical[57] levels may not be sustainable without additional funding, and the parties' recommendations present options for accomplishing a more aggressive renewables target.

We continue to believe that a minimum renewables purchase requirement is the best approach to meet our resource diversity goals. This can be achieved by placing the requirement on either retail providers of electricity, or on generators.

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[56] The 3.3% of revenues would be for investments in energy efficiency, renewables, and transmission and distribution RD&D, but the MOU does not recommend specific allocations to each of these components. It is also unclear whether this funding is meant to apply only to incremental renewable resources or would include existing renewable expenditures. As discussed above, existing renewable resources are either utility-owned or funded under existing QF contracts, and therefore any above-market costs should be covered under the QF transition cost recovery mechanism.

[57] Current levels may differ from levels of even two years ago because of contract buyouts which have reduced the amount of renewables on the system. To the extent buyouts. continue to occur, maintaining the target will require the procurement of new renewable resources and may require additional funding.

We have not concluded at this time on whom this obligation should be placed. We hope that the Working Group will provide us with further guidance on this, and will address this question further as we implement this decision. Regardless of where the obligation resides, it would be a condition of certification. We prefer that the requirement be set at the same level for all electric utilities on a statewide basis, but recognize that it may be appropriate to develop a transitional strategy given the current resource portfolios of some utilities. Credits for meeting this requirement would be tradeable, similar to tradeable permits programs adopted by Congress in the Clean Air Act Amendments of 1990 and the South Coast Air Quality Management District's Regional Clean Air Incentive Market, in order to allow retail providers the most flexibility in meeting this requirement. We would expect that these minimum renewables levels would be in place beginning in 1998 and continuing through 2000, at which point we would revisit whether the requirement should be modified. As with the tradeable permits programs mentioned above, a meaningful penalty for noncompliance should be established.

We recognize that we will need information on the level of renewables on the utility systems from 1990 to the present, and will identify how we will gather this information when we develop our procedural roadmap (See Section VIII). This information will allow us to determine the appropriate level for the minimum renewable requirement, whether the requirement should be established on a percentage of megawatts or percentage of megawatt-hours basis, and whether a transitional strategy to a statewide minimum level is necessary. We also believe that it may be appropriate to establish floors for certain technology types, in order to maintain the diversity of our renewable resources; this should be explored in the information-gathering process. The cost of the noncompliance penalty will be explored as well.

This market-based approach will allow buyers and sellers to search the market for the best renewables bargains and to internalize such costs in their prices without the need for a surcharge to fund renewables development. Establishing a surcharge to fund new renewables development would require some sort of prescribed allocation mechanism or bidding procedure to disperse the funds. We could use an administrative approach to ensure compliance, but after our experience in the BRPU we are hesitant to do so. The minimum renewables requirement approach will allow the market to provide the most cost-effective renewable resources, without our intervention. Allowing providers to trade in order to meet the renewables requirement may also serve to minimize the stranded costs associated with existing QF contracts by providing new markets for QFs' power. Renewables research and development will be likely to occur under this approach as electricity demand grows and existing renewables are replaced with new renewable resources to meet the minimum requirement.

B. Energy Efficiency

Under the current regulatory framework we authorize funding which allows utilities to pursue energy efficiency, load management, and other demand-side management (DSM) investments that meet specified tests of cost-effectiveness. Information and energy management services programs are also funded but are not required to pass stringent cost-effectiveness hurdles.[58] Both May proposals recommended a two-track approach to DSM, similar to that suggested by the Working Group. The May proposals indicated that customer-specific energy efficiency projects should not require future funding from ratepayers, but should instead rely on market-driven funding mechanisms (Track 1). The proposals emphasized that continued funding was appropriate for activities that are designed to transform the energy efficiency market and would not naturally be provided by a competitive market (Track 2). The proposals did not indicate a preference for the recovery mechanism to fund energy efficiency efforts not naturally provided by the marketplace, nor for a specific means to distribute the funds.

Both proposals looked to the Legislature for guidance in arriving at the appropriate level of funding and the means to administer those funds. Fees and trusts were mentioned as options.

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[58] We also authorize funding for low-income weatherization programs as part of the DSM funding level. We address low-income weatherization funding in the discussion of low-income assistance programs.

In its comments on the May proposals, DGS supported the collection of funds through a universal distribution charge and recommended making the funds available on a competitive basis to utilities and nonutilities alike. CLECA supports a surcharge and provides a suggested list of criteria which DSM programs funded by the surcharge should meet. The Southern California Cities Joint Powers Consortium and Turlock Irrigation District recommend use of a surcharge for environmental protection, which appears to cover both energy efficiency and renewables. SCE supports a distribution charge for all customers. SDG&E believes distribution utilities should continue to implement market transformation DSM programs as they have successfully been doing for many years; in the long term, SDG&E supports a bypass-proof collection mechanism. SESCO supports competitive access to DSM funds.

The MOU recommends that the Commission establish a funding level for cost-effective expenditures by utilities and others, not to exceed 3.3% of revenue requirements as of January 1, 1995, collected through a surcharge.[59] The MOU does not provide for funding of energy efficiency efforts that do not pass cost-effectiveness tests. Many programs with a market transformation, information, or education focus are not likely to be provided by the competitive market and are also not likely to pass this cost-effectiveness screen. The MOU approach is unlikely to provide funding for such programs.

The Framework Parties also support a surcharge for collection of funds but do not place a limit on that funding. The Framework Parties recommend that utilities continue to administer funds for energy efficiency and conservation programs in the near term, but support development of an independent administrator over the long run. The Framework Parties raise the concern that

[59] As previously mentioned, the 3.3% of revenues would cover total, unallocated investments in energy efficiency, renewables, and transmission and distribution RD&D. It is unclear how this level was developed, and what current costs it includes. CLECA's July 24, 1995 comments recommended a comparable approach, limited to 3% of revenues.

utilities should not be allowed to use these funds to establish market power or retain market share.

The CEC has convened an Energy Services Working Group (ESWG) as part of its Energy Efficiency Report process to consider how best to promote energy efficiency in a restructured industry. That group has submitted a report to the CEC which recommends policies for legislative action. The ESWG recommendations include a surcharge to fund energy efficiency programs and energy efficiency RD&D beginning January 1, 1996 and support of more market-driven approaches to funding; funding levels and administration of the funds are topics for future discussion. As a transitional strategy, the ESWG proposes that the Commission oversee utility expenditures for DSM programs, as it does today, until 1998, while market structure details are worked out.

Support for a surcharge for funding energy efficiency and conservation programs is very strong. Parties do not agree on the types of programs the surcharge would encompass within the funding level or the dividing line between the two tracks. Parties are unclear or vague about their positions regarding the appropriate level of funding for energy efficiency or the means to administer funds.

In considering the future role of electric utilities in funding and administering DSM activities, we must consider the appropriate application of state policy to a dramatically changing industry. State policy supports utility pursuit of energy efficiency which is not being pursued by other entities (see § 701.1). We have promoted utility involvement in these programs to ensure that Californians received the benefits of energy efficiency, consistent with our resource procurement goal of providing least-cost, reliable, environmentally sensitive energy services. The primary motive behind utility investment in energy efficiency has been to defer or avoid the high costs of new generation. However, in a restructured environment, evaluating cost-effectiveness on the basis of utility resource deferral may no longer be as relevant. The May proposals stated a preference for publicly funded energy efficiency programs to shift to those programs in the broader public interest, for example, programs with market transformation effects and education efforts that would not otherwise be provided by the competitive market. We continue to prefer this two-track approach.

We recognize that there are many definitions of market transformation and education activities, and we will not attempt to refine those definitions today. In general, it is appropriate to use public funding to ensure that energy users have information about managing their energy use. It may be appropriate to have more public resources available for educating residential and small business customers than large electricity users, because large users generally have more resources to dedicate to managing their energy use.

It may also be appropriate to continue to provide financial incentives for energy efficient products and services. Any such financial incentives should be focused on transforming the market for energy efficient products and services; some examples of these activities are the Super-Efficient Refrigerator Program,[60] and manufacturer rebates for compact fluorescent light bulbs and high-efficiency motors. We expect that public funding would be needed only for specified and limited periods of time, to cause the market to be transformed. Given our focus on market transformation efforts, we disagree with DRA's comments that surcharge funds should predominantly be used as a source of capital for the installation of demand-reducing technologies and measures (October 2, 1995 Comments on MOU, p. 31).

We suggest to the Legislature the adoption of a surcharge to fund energy efficiency activities as discussed above. The surcharge would be applied in the same manner as the CTC and be nonbypassable. We do not intend for the surcharge to collect funds to pursue energy

[60] To encourage manufacturers to produce super-efficient refrigerators that significantly exceed appliance efficiency standards, a nationwide consortium of utilities and other entities established a competition between manufacturers to design and market super-efficient refrigerators. The utilities contributed funding to provide a prize for the manufacturer whose product won the competition. This effort motivated manufacturers to produce higher efficiency refrigerators earlier than expected, transforming the market for this product.

efficiency activities that the competitive market will provide on its own. Delineating between competitive and other DSM activities will be difficult. After a short transition period, we believe the funds collected through a surcharge for energy efficiency should be competitively allocated by an independent, nonprofit organization, but we would like to capture the expertise and knowledge that the utilities have gained in administering DSM programs as we begin the transition. We expect to reach closure on this issue through the implementation activities we will undertake in the next few months and through ongoing coordination with the Legislature.

We anticipate that by January 1, 1997, energy efficiency costs should no longer be embedded in electric rates and instead should be collected as part of the "public goods charge" (PGC) applied to retail electric sales.[61] Assuming the Legislature adopts a PGC, it should initially be a line item on utility bills and then change to a surcharge, depending on when legislation adopting such a surcharge is enacted. Initially the line item rate should be set for each utility's service territory to correspond to authorized DSM funding.[62] We will modify the level to be collected once we determine the appropriate level of public funding consistent with the above discussion and the workshops we anticipate conducting as part of our implementation of this decision. Until public funding for DSM activities is removed from rates and collected through a surcharge, an Electric Revenue Adjustment Mechanism (ERAM)-type mechanism shall be retained to account for energy efficiency impacts. Over time, we prefer to see the same surcharge applied consistently across all utilities' service territories.

We anticipate that our implementation of this decision will include workshops that will develop information to allow us to establish what types of energy efficiency activities should be

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[61] The public goods charge will collect funds for various activities, including energy efficiency.

[62] We recognize that the authorized level of DSM funding is at issue in SCE's 1995 General Rate Case (GRC) and PG&E's 1996 GRC.

funded through the surcharge, consistent with our guidance above.[63] This guidance should be considered a starting point and not final; if the workshops flesh out the two tracks in more detail and identify areas where public funding should be expanded or limited, we will consider modifying our definition. Therefore, we do not adopt a specified percentage cap for the charge at this time, as proposed by the MOU. If we order workshops, we will direct workshop participants to explore the details of an independent administrator of these funds and the transition period necessary to move to an independent administrator. How utility expertise can be captured should be explored as well. Because Legislation to ensure the surcharge is nonbypassable is desirable, we will likely ask that the workshops be used to assist us in developing proposed language for that legislation.

C. Research, Development and Demonstration

Electric utility RD&D programs today support both regulated business functions and public purpose goals. For example, the utility conducts research on generation, transmission, distribution, environmental compliance, service and safety, energy efficiency, and low-emission vehicles. Our May proposals recognized that the utility will have a need to conduct research to support its continuing monopoly functions, and that research that serves a broader public interest which may not be pursued by the monopoly should not be lost in the transition to a more competitive environment. Our proposals also noted that in anticipation of full competition in the generation sector, the remaining monopoly utility should no longer use ratepayer funds for generation RD&D.

Both proposals endorsed the Working Group's option of a Consortium or Public Authority to administer public goods funds collected through a surcharge. The surcharge would be calculated to generate funding at current or historical levels, or legislatively adopted levels, for

[63] Gas utilities should also participate in this process in order to provide consistent treatment of comparable costs among competitors.

public goods research. The proposals stated that research supporting regulated functions should continue to be funded through utility rates, not through a surcharge.

Few parties commented directly on the proposals' RD&D policies; those who commented supported a surcharge to fund RD&D.[64] The CEC supports continuation of public goods research by utilities during the transition to a more competitive market and notes that despite statements in the proposals in support of public goods research during the transition, the Commission has allowed utilities to decrease RD&D budgets significantly in these areas.

The MOU includes funding for research for regulated transmission and distribution services as part of the 3.3% surcharge on total revenues. It does not address public goods research. The MOU diverges from the May proposals because it would use a surcharge to collect funds for RD&D programs that serve a regulated function. The May proposals anticipated that a surcharge would be used to fund public goods research only. The Framework Parties recommend near-term funding for energy efficiency and renewable RD&D consistent with historical levels, and specifically recommend restoration of funding for the California Institute for Energy Efficiency. For the long term, they propose to provide RD&D for energy efficiency and emerging renewable technologies through an independent institute, funded by a surcharge.

We reaffirm that the surcharge should collect funds for public goods research only, not funds for regulated or competitive research functions. The monopoly utility should no longer collect ratepayer funds for generation-related research as of January 1, 1997. Funds for research in support of regulated functions properly remain part of regulated rates.

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[64] The CEC supports use of a surcharge to collect funds for public goods research. The CEC supports the proposal that funds for research related to monopoly functions should continue to be collected through rates. In their joint comments, PG&E and NRDC do not differentiate what type of research would be supported by funds collected through a surcharge.

We recognize that drawing the line between competitive, regulated, and public goods RD&D activities will be difficult.[65] We do not intend for the surcharge to collect funds to pursue research that the competitive market will provide on its own. After a transition period, perhaps by January 1, 1998, the funds collected through a surcharge for public goods research should be administered by an independent, nonutility entity.

By January 1, 1997, the public goods RD&D costs should no longer be embedded in electric rates and instead should be collected as part of the PGC applied to retail electric sales.

We anticipate that our implementation of this decision will include workshops to develop information to allow us to establish the boundaries between competitive, regulated, and public goods research, and to develop the public goods RD&D costs and transition policies for an independent administrator. We will also work with the Legislature to change §§ 740.1 and 740.3,[66] and we will modify existing Commission decisions to implement these policies, assuming the Legislature agrees with us.

D. Baseline Rates

The baseline rates program is designed to provide residential customers with a specified quantity of electricity (sufficient to supply reasonable energy needs of an average residential user) at a lower rate.[67] The pool proposal suggested that the utility would continue to offer

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[65] For example, under our adopted minimum renewables requirement, the competitive market will likely pursue renewables research, but such research has often been considered public goods research. Research related to nuclear waste management, which is tied to nuclear generation, is another area that may provide public benefits but is a component of generation-related RD&D. As these examples demonstrate, research often results in benefits to the general public without having these benefits as its primary focus.

[66] Because § 740.2 will expire on January 1, 1997, we do not include it on our list of desired legislative modifications.

[67] The Legislature and Governor have signaled their continuing support of the baseline rates concept with the passage of SB 248, which amended § 739 to expand the category of

baseline rates but that the entry of new, unregulated providers would require us to reconsider how this program is implemented. The direct access proposal would have the utility offer baseline rates, but new entrants would not be required to do so since they would not be defined as public utilities.

The Framework Parties recommend that baseline rates be continued. If rates are unbundled, the baseline concept would be continued through a rate differential on transmission and distribution rates. DRA's comments on the May proposals correctly observe that as "electric restructuring moves forward and we move from cost-of-service regulation to performance-based regulation, utilities may start to feel the pressure of moving rates closer to true costs. As this happens, it is possible that baseline rates will disappear and utilities may impose a fixed monthly customer service charge on residential customers. Since low-income customers consume less than other residential customers, the impact of such charges could be a substantial bill increase" (p. 29).

The Framework Parties, many of whom represent residential and low-income customers, are concerned with what they perceive in the May proposals as a lack of commitment to continuing the baseline rate program. The proposals recognized the difficulty of implementing baseline rates in a more competitive environment as rate design principles change and new market entrants emerge. We are not suggesting the abandonment of baseline rate implementation, but we see inherent conflicts between the types of innovative service offerings new competitors may propose and mandating a specified rate design approach. We would like to receive more information that will allow us to continue effective baseline rates under the market structure adopted today, and that will help to minimize the concerns expressed by Framework Parties. In a subsequent ruling, we will establish a procedural schedule for receiving that

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customers eligible for medical baseline quantities.

information. In the meantime, all electric service providers under our jurisdiction will be required to offer eligible customers service consistent with § 739.

E. Low-Income Assistance

The Commission currently implements two types of assistance to low-income residents: rate assistance and weatherization and efficiency services. Rate assistance is provided consistent with §§ 739.1 and 739.2 under the California Alternate Rates for Energy (CARE) program. Under this program, eligible low-income households and group living facilities receive a discounted rate for their electric and gas consumption.[68] Costs associated with the rate discount are currently collected as a cents-per-kWh component of rates. Costs of low-income efficiency services costs have been incorporated in general rate case funding for DSM programs; the programs have been administered by the utilities but generally implemented by a variety of community-based organizations or through competitive bidding. Low-income efficiency services are implemented pursuant to § 2790.

Under the terms of recent legislation supported by Southern California Gas Company (SoCalGas) (SB 678, Polanco), costs associated with CARE and low-income efficiency services would be removed from gas rates and recovered as a surcharge applied to all gas consumption.[69] This bill is designed to ensure that all gas consumers contribute on an equivalent basis to funding the low-income assistance programs. SB 678 requires that the costs collected through the surcharge not exceed the amount currently in rates.

The May proposals both recommend continuation of these programs and a commitment to retain funding for them, through a line-item charge on customers' bills, but suggest that the

[68] Low-income assistance programs are provided by both gas and electric utilities. Gas and electric utilities should be treated consistently to ensure that low-income residents receive comprehensive assistance in managing their energy use.

[69] This would in essence create a tax on all gas consumption, with some exceptions. SB 678 was not passed by the Legislature in 1995 and has become a two-year bill.

Legislature should consider transferring these responsibilities to another entity in a restructured environment. The Universal Lifeline Telecommunications Service (ULTS) fund is cited as a model.

The MOU and the Framework Parties propose to recover CARE program costs through a nonbypassable charge at levels sufficient to cover all eligible recipients who apply.[70] The MOU recommends that low-income efficiency services costs be recovered at the 1995 funding level. The Framework Parties recommend that the nonbypassable charge should be designed to improve on current funding and participation levels for both CARE and low-income efficiency services, without a funding cap.

We could today require utilities to identify low-income assistance costs as a line item on bills; in fact, this already occurs for some nonresidential customers for CARE costs. The Greenlining Institute, NRDC, UCAN, and TURN argue against line-item identification and point out that itemizing only public policy programs stigmatizes these programs in the eyes of customers, and that other components of utility costs are equally as important to reveal, especially given their impact on rates and bills.

We are concerned about the ramifications of itemizing low-income assistance as a line item during the transition period. The beneficiaries of low-income assistance have little political power, and line-item listing could make this program vulnerable to lobbying efforts by more powerful opponents. The limited rate impact also argues against line-item treatment.[71] Our policy preference is to recover these low-income assistance costs as a surcharge on electricity use

[70] Comments by CLECA also support this approach.

[71] According to the Fifth Annual Low-Income Ratepayer Assistance Program Report submitted in July 1995 in I.88-07-009, during the May 1993 to April 1994 reporting period, statewide electric utility costs for the Low-Income Rate Assistance program (now CARE) were $64.2 million. This amount is less than 0.4% of the total statewide electric revenue requirement of about $17 billion.

separate from other public goods charges. Direct access customers would not be able to evade this surcharge by selecting a supplier other than the utility. We establish this separate low-income assistance surcharge to provide a clear funding source for low-income programs which will not be mingled with funds collected for other purposes. Funding for low-income rate discounts recovered through a surcharge should not be capped at current levels but should instead be based on need. We would prefer to see the same level of surcharge applied across the state rather than on a service territory basis as occurs today, but recognize that there may be some transition period necessary to accomplish this goal. We will work with the Legislature to develop any legislation needed to facilitate this change.

In the near term the utilities should continue to administer these programs. The proposal to move administration outside of the utilities is appealing. Low-income assistance funds could be transferred to a ULTS-like fund for distribution, as many parties have suggested.[72] Any energy provider could use these funds to provide rate discounts to eligible customers, and energy service companies or nonprofit community-based organizations would compete for use of the funds to provide low-income efficiency services. CARE funds should be used for a customer discount that appears on the bill rather than an after-the-fact refund or rebate.[73] There are significant questions regarding how the funds collected for rate discounts would be administered and provided to eligible customers. We need additional information in order to develop the details of how to administer these funds effectively.

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[72] The ULTS fund may not have a direct analogy to energy because there is no standard package of basic services for energy as there is for telecommunications.

[73] It may be appropriate to extend a reduced service establishment fee to low-income customers as part of the program, as has been implemented for SoCalGas. This can occur today and will serve to reduce outreach costs associated with CARE programs. In addition, the utilities should continue to provide discounted monthly service charges to eligible low-income customers.

Another unresolved issue is whether the level of funding for low-income efficiency services should be capped or uncapped. We would like to see a more detailed analysis of the need for low-income efficiency services before we decide whether the amount of funds collected for these services should be capped on uncapped.[74] A subsequent ruling will lay out a schedule for receiving a report on these unresolved questions and identify the issues the report should address. After we have received the report, we will make a recommendation to the Legislature regarding statutory changes that would help us in continuing our support of low-income efficiency services.

F. Women, Minority, Disabled Veteran Business Enterprises

Section 8281 states, "The opportunity for full participation in our free enterprise system by women, minority, disabled veteran business enterprises is essential if this state is to attain social and economic equality for those businesses and improve the functioning of the state economy." To implement § 8281 et seq., General Order (GO) 156 initiated the WMDVBE program in 1987, and established goals for regulated utilities' procurement practices. The goals encourage awards of not less than 15% of all contracts for goods and services to minority-owned businesses and not less than 5% to women-owned businesses. Following a 1990 amendment to the Public Utilities Code, GO 156 was expanded to include disabled veteran-owned businesses.

The program is voluntary and goal oriented, not a set-aside program. GO 156 established that utilities should develop outreach programs, internal training of utility procurement staff, and a subcontracting program that encourages prime contractors to use WMDVBE subcontractors. The Commission also oversees a clearinghouse which verifies WMDVBE status. By the end of 1993, utilities had made significant progress toward meeting the goals and in some cases had exceeded them.

[74] For example, we would like to see information about the low-income population size, customers served under current utility programs, types of measures installed, and saturation studies, to name just a few.

The May proposals both support continuation of WMDVBE policies in the restructured electric services industry as they apply to regulated utilities. Both indicate that the utility should continue to be held to the goals established in GO 156. The pool proposal states that to the extent the electric utilities remain involved in generation procurement service, GO 156 will apply as it does today. Under the direct access proposal, compliance costs would be reflected in transmission and distribution rates or in utility procurement services. Both proposals, as well as the Working Group, suggest that the Legislature consider other options, including expansion of the policies to all providers or a complete elimination of the policies.

The Greenlining Institute and Latino Issues Forum recommend expanding the application of the WMDVBE program to include unregulated and out-of-state utilities, as well as other suppliers, generators, and distributors; no other parties commented specifically on this issue. The MOU is silent on this issue. The Framework Parties recommend that any costs necessary to continue WMDVBE programs at current levels should be included as part of a surcharge.

We will apply the WMDVBE statutes and GO 156, unless and until we receive other direction from the Legislature. Generation and related procurement by the regulated utility should be subject to these goals, just as fuel procurement is today.

Costs to comply with GO 156 are related to outreach, internal training, and subcontracting programs, as well as funding the clearinghouse that verifies WMDVBE status. The magnitude of the total compliance costs is so small as to not show up on a typical residential monthly bill.[75] For that reason, we will not separately identify these costs on customer bills but will continue to compensate utilities for these costs within the regulated revenue requirement. We do not believe that additional funding or changes to the WMDVBE program are needed for the program to go forward after industry restructuring.

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[75] Based on our review of the utility annual reports on WMDVBE, total statewide costs for electric utility compliance with the WMDVBE program were approximately $4 million in 1994. This amount is less than 0.03% of a statewide revenue requirement of $17 billion.

G. Economic Development Programs

Sections 740.4 and 740.7 allows for funding of utility economic development activities to the extent of ratepayer benefit.[76] The direct access proposal recommended that economic development program costs authorized by the Commission should be separately identified as a line item. Both May proposals recommended legislative reconsideration of the utilities' role in these programs in the long term, and raise the possibility of taxpayer funding of these activities. We will continue to apply our existing guidelines to funding requests for utility economic development programs. Costs authorized for these activities should be identified as line items on customer bills effective January 1, 1997. We encourage the Legislature to consider whether continuation of utility funding is consistent with a competitive marketplace in the long term.

H. Special Rate Discounts

We currently allow utilities to offer special rates to certain customers based on various statutes (see, for example, §§ 743, 743.1, 744). Utilities are also allowed to offer rate discounts to defer bypass of their systems. Cost-shifting caused by these programs arises because, in general, 100% of the costs associated with discounts are recovered from ratepayers. The costs for these programs are difficult to discern because they are embedded in historical rate design practices. In PG&E's recent Rate Design Window proceeding, we adopted PG&E's proposal that until restructuring is implemented, costs associated with rate discounts should be split between ratepayers and shareholders; once restructuring is in place, 100% of the costs will be borne by shareholders (D.95-10-033). Shifting the cost of discounts to shareholders once greater consumer choice is available is consistent the May proposals.

In D.95-10-033, we recognized that the existence of ERAM gives a utility little incentive to rigorously negotiate the smallest discount necessary to retain a specific customer, because

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[76] In general, the economic development programs anticipated by § 740.4 are not rate related, but instead provide technical, marketing, or relocation assistance.

ratepayers effectively compensate the utility for the amount of the discount. We see that this situation will persist in the future, and that retention of customers through rate discounts during the transition period and into the era of competition confers strategic benefits to utility shareholders. In keeping with our policies in D.95-10-033, revenue shortfalls resulting from new rate discounts offered to avoid customer bypass, attract new business, or retain existing or expanding businesses should be shared between ratepayers and shareholders during the transition to a restructured industry.

We will apply these cost-sharing policies to all rate discount cases that come before us during the transition period, including those currently pending. Once restructuring is in place, utilities will not be able to pass the costs of discounts to ratepayers; instead, shareholders should fund any discounts offered to customers.

I. Low-Emission Vehicles

Section 740.2 requires the Commission to encourage energy utilities to conduct research on electric and natural gas vehicles, and § 740.3 requires the Commission to implement policies to promote and facilitate development of equipment and infrastructure for low-emission vehicles. Section 740.3 also provides for the recovery in rates of costs incurred in the ratepayers' interest. In D.93-07-054, the Commission established funding guidelines.

Our policies on low-emission vehicles have been addressed in I.91-10-029. That proceeding determined the level of utility funding over the next six years. Utility involvement in LEV programs is primarily focused on building utility infrastructure which will support the use of alternate fuel vehicles. We must determine whether the authorized funding level will be collected within the bundled rate or through a surcharge.[77]

Utility involvement in these programs is motivated by public policy goals, which argues that these costs should be recovered as part of the PGC. The funding we are considering in the

[77] Comparable treatment of these costs for both electric and gas utilities should occur.

LEV proceeding is primarily related to utility infrastructure development, arguably part of the distribution utility's functions. Some of the costs associated with infrastructure development are expected to be credited back to ratepayers through charges to LEV rates. Utility customers, unlike nonutility customers, are able to benefit from these expenditures directly through their eligibility for utility LEV programs. For this reason, the costs of utility LEV programs should continue to be collected by the regulated utility and identified as a line item on customer bills, as opposed to being collected as part of the PGC.

J. Undergrounding

One issue not specifically addressed in the May proposals or the MOU is utility expenditures for replacing overhead electric facilities with equivalent underground lines along public streets and roads and on public lands and private rights of way. Undergrounding is carried out by the utilities under a tariffed program. Undergrounding is pursued once a governing civic body has determined that such undergrounding is in the public interest.[78]

We raise this issue because it represents a utility cost which exceeds the costs associated with several of the programs identified above.[79] It is an item that, if allowed to become discretionary, could be expected to be eliminated from the utilities' planned expenditures in a competitive marketplace. It is also a program that the cities and counties of California rely upon as part of their local improvement efforts. This undergrounding activity remains an appropriate activity of the regulated utility, not subject to competition, and therefore should be collected through regulated utility rates.

[78] The public interest in undergrounding is found where undergrounding will eliminate an unusually heavy concentration of overhead electric facilities, the area is heavily used by the public and carries a heavy volume of pedestrian or vehicular traffic, and the area is next to or in a civic area or public recreation area or an area of unusual scenic interest.

[79] In its June 24, 1994 comments PG&E identified distribution line undergrounding to have an annual cost of $50 million, approximately 0.6% of an $8 billion revenue requirement.

VII. APPLICATION OF CALIFORNIA ENVIRONMENTAL QUALITY ACT

We are persuaded that we should conduct a review of our restructuring proceeding under the California Environmental Quality Act (CEQA) (Pub. Res. Code §§ 21000-21178.1). The restructuring effort represents a policy shift of great scope for the Commission; there is no harm, and abundant good, in moving forth with analysis under CEQA at this time. The magnitude of our proposed electric policy favors reviewing the possible environmental impacts of a new industry structure. Furthermore, the delay which could result from erroneously failing to undertake the CEQA review process could severely hamper restructuring efforts which we deem vital to California's economy.

CEQA requires state agencies to evaluate the environmental impacts of any discretionary project they approve, unless the project is exempt. When an agency determines that a project may have a significant effect on the environment, it must prepare an Environmental Impact Report (EIR). If the project will not have a significant effect on the environment, the agency may prepare a negative declaration rather than an EIR.

On June 20, 1994, the Natural Resources Defense Council (NRDC) filed a Motion for Determination of CEQA Applicability under Rule 17.2 of the Commission's Rules of Practice and Procedure. In its motion, the NRDC argues that CEQA is applicable to the actions we are considering taking in this proceeding. In D.94-12-027, we responded to the NRDC's motion and committed to determine the applicability of CEQA once we were in a position to frame our policy decision (Ordering Paragraph No. 8). In offering two policy proposals for comment in D.95-05-045, we solicited the views of interested parties on this question. Nine parties filed comments on this issue, with two stating that CEQA is not applicable to the actions recommended in the May proposals, six concluding that CEQA is applicable and one which did not take a position but urged a quick resolution of the issue.

Whether CEQA applies to our electric restructuring rulemaking and investigation turns on whether the restructuring fits within the CEQA definition of a project. The State CEQA Guidelines (14 Cal. Code of Regs. §§ 15000-15387) define "project," in relevant part, as:

> ". . . the whole of an action which has the potential for resulting in a physical change in the environment, directly or ultimately, and . . . is . . . (1) An activity directly undertaken by any public agency." (CEQA Guidelines § 15378.)

As noted, parties to this proceeding differ in their view as to whether CEQA applies and, if it does, differ on the required compliance procedures. We have turned to decisional law to resolve these issues. It is clear that our Supreme Court has interpreted the Guidelines' definition of a project in a manner that does not require a finding of a direct physical effect on the environment. *Bozung v. Local Agency Formation Commission* (1975) 13 Cal.3d 263. At the same time, the courts have not been completely clear about whether policy actions without clearly identifiable and direct environmental effects are CEQA projects. (See, e.g., *City of Agoura Hills v. Local Agency Formation Commission* (1988) 198 Cal. App.3d 480, 494.)

We cannot make a finding at this time about whether electric restructuring constitutes a CEQA project. However, we can anticipate that there is no harm, and abundant good, in moving forth with analysis under CEQA at this time. We find preparation of an EIR, as opposed to a negative declaration, is appropriate in the instant proceeding. CEQA requires the preparation of an EIR whenever "it can be fairly argued on the basis of substantial evidence that the project may have a significant effect on the environment . . . ." *No Oil v. City of Los Angeles* (1975) 13 Cal.3d 68, 75. Often this determination is made after an agency conducts an initial study of the project. However, "[i]f the lead agency can determine that an EIR will clearly be required for the project, an initial study is not required. . . ." (CEQA Guidelines § 15063 (a).)

The restructuring proceeding may potentially impact the environment in a number of ways. In its motion and comments, the NRDC cites, among other factors, the potential impact of reduced opportunities for energy efficiency incentives and restoration of a linkage between utilities' profits and sales volumes. More generally, PG&E refers to resulting shifts in energy production and argues, "These shifts have the potential to create environmental impacts since the mix of energy resources cumulatively creates a different set of environmental and related socioeconomic impacts." (Comments of PG&E, July 24, 1995, at p. 14.)

Having concluded that we will prepare an EIR, we agree with PG&E that we should "proceed with the EIR process to avoid potential delay, rather than focus its efforts on changes to the proposals which might avoid the need for CEQA review." (Id.) For this reason we will dispense with the preparation of an initial study and prepare an EIR on the restructuring policy described in this decision.[80]

Within 100 days of the effective date of this decision, CACD shall issue a Notice of Preparation of an EIR (NOP) and retain the services of a qualified professional environmental consultant who will be approved by the Commissioners. This consultant will work with the Commission to prepare an EIR which will present the analysis of the environmental impacts of the policy adopted in this decision, compare environmental effects of the alternatives and, if necessary, identify mitigation measures for any potentially significant impacts. Due to the general nature of our policy, the scope of this EIR will be more conceptual than a site-specific EIR would be. This EIR will attempt to anticipate likely future scenarios that could develop under our policy, and will therefore contain a more general discussion of impacts, alternatives, and mitigations than is typical for discrete, site-specific projects. Additionally, the EIR may incorporate or refer to the Environmental Impact Statement (EIS) being prepared by FERC under the National Environmental Policy Act on its MegaNOPR. The Commission is committed to

[80] Each of the electric utilities shall reimburse the Commission for CACD's costs in preparing this EIR, and shall share and recover these costs in the manner employed to allocate and recover the Public Utilities Commission Reimbursement Account fees. We further direct the Executive Director to ensure that all due diligence is used by this Commission to control the costs of preparing this EIR in full compliance with CEQA and Rule 17.1.

complying with all relevant CEQA requirements. Further details on the EIR preparation process will be issued in our forthcoming NOP.

VIII. IMPLEMENTATION

Today's order represents a major first step in our transition to competitive markets. While the decision provides necessary policy guidance, the task of working to craft the necessary details and the pursuit of these objectives will be complicated and draw on the talents and cooperation of all stakeholders. This section outlines the implementation process which must now begin. This process is described below. We identify those activities that will be undertaken by stakeholders, and those activities that we will undertake ourselves.

As we explained in Section II, this decision is effective today, but, as provided for in D.94-12-027 and D.95-05-045, we will not take steps to carry out our policies for 100 days. During this period, we expect the Legislature will have an opportunity to examine our policy choices. We also will be developing a consolidated procedural approach, described below, so that we may accommodate any necessary modifications to smooth our transition to a competitive framework. It is essential, however, that we move forward expeditiously on preliminary implementation details, so that all required components are in place by the anticipated beginning of the transition period, no later than January 1, 1998.

A. A Consolidated Approach for Implementation

There are many procedural steps that must be completed over the next two years as we prepare to implement the reforms in this decision. We need a well-organized process that will allow us to achieve these milestones along the way. We intend to develop a roadmap process similar to the one we are employing in our proceedings to open local telephone markets to competition.[81] We anticipate that in the next 45 days, we will issue for comment an outline of this roadmap process for electric industry restructuring.

[81] See D.94-12-053 which established procedures and a workplan to manage the transition to competition by January 1, 1997.

The roadmap structure allows involvement from decision makers early in the process, and maximizes the resources of both parties and staff. While we are still developing the details of this plan, the management structure will have a role for each Commissioner. Issues will be broadly grouped into four subject areas (these areas are one of the things that will be developed more fully in the draft management plan we will issue for comment in 45 days). For each broad subject area, there will be an assigned commissioner. The assigned commissioner will work with a staff team that includes an assigned Administrative Law Judge for that particular subject area, and representatives from all relevant areas of our staff.

This process will be facilitated by a managing commissioner. Like the commissioners working in specific areas, the managing commissioner will work with a staff team from various divisions. This team's responsibilities will be to keep the overall process moving forward and on schedule, coordinate the different phases and subject areas, and ensure consistency across policies and subject areas. This team will focus on process as opposed to content, with a goal of keeping the various proceedings on track so we can meet our implementation date of no later than January 1, 1998. Moreover, this team will serve as a focal point for reports to the Legislature and communication with the Legislature on electric restructuring, coordinating requests for information and making sure Legislators are receiving the right information from the right proceeding. This process will be maintained as an agenda item at each Commission meeting to provide the opportunity to discuss any coordination issues that may arise.

1. The Working Group

In D.95-05-045, we called for the Working Group to reconvene two weeks after the issuance of our policy decision to address implementation issues. We reaffirm today that the Working Group will be integral to the roadmap we adopt. However, we will not formally order the Working Group to reconvene until we have had ample opportunity to identify what we expect the Working Group to accomplish. This does not mean that the Working Group may not commence its efforts now, concurrent with our development of a procedural roadmap, in order to jump start the process.

2. Activities that Must be Initiated Within Next 100 Days

The following chart lists those actions whose commencement cannot await the adoption of a roadmap, even though they will be part of whatever roadmap we eventually adopt:

ACTIVITY	PARTY	DATE DUE
Advice letter: CTC notice to customers added to Preliminary Statements	PG&E SCE SDG&E	30 days after effective date
Proposals to establish initial phase of Direct Access and eligibility	PG&E SCE SDG&E	30 days after effective date
Comments on proposals to establish Direct Access	Any interested party	60 days after effective date
Reply comments on direct access	Utilities	75 days after effective date
Implementation Roadmap	Commission	45 days after effective date
Applications for ratemaking treatment of Diablo Canyon and Palo Verde	PG&E SCE	100 days after effective date
Comments on separation of distribution, transmission, and generation	PG&E SCE SDG&E	90 days after effective date
Application for voluntary divestiture of up to 50% fossil generation	PG&E SCE	90 days after effective date
Reply comments on separation	Any interested party	150 days after effective date
Responses to applications for voluntary divestiture of up to 50% fossil generation	Any interested party	135 days after effective date
Notice of preparation of EIR	Commission	100 days after effective date
Applications to identify and value undepreciated sunk costs of nonnuclear generation assets	PG&E SCE SDG&E	April 1, 1996

ACTIVITY	PARTY	DATE DUE
Proposals to establish ISO filed simultaneously with CPUC and FERC; Proposals to establish Power Exchange filed simultaneously with CPUC and FERC	PG&E SCE SDG&E	130 days after effective date
Comments on proposals to establish ISO; comments on proposals to establish Power Exchange	Parties	160 days after effective date
Reply comments on proposals to establish ISO; reply comments on proposals to establish Power Exchange	PG&E SCE SDG&E	175 days after effective date
Applications for first CTC proceeding	PG&E SCE SDG&E	September 1, 1996

3. Issues the Roadmap will Likely Address

Almost every topic addressed in this decision will need to be developed more fully as we move to implementation. At this time, we anticipate that the roadmap will, at a minimum, include the following:

- Proceeding to unbundle transmission and distribution functions
- Obligations of the utility distribution company
- Real-time pricing and metering issues
- PBR mechanisms
- Market power
- Transition costs
- Public purpose programs and enabling legislation[82]

[82] We expect to work closely with the Legislature on public purpose programs to ensure that the programs continue to meet Legislative goals. It is possible that some public purpose programs will not be effective or will need to be revamped in a competitive marketplace. Recognizing the Legislature's role as crafter of these policies, we will work closely with the Legislature and interested parties to refine the programs that implement these policies.

B. The Commission's Role During Transition and Beyond

As we enter the transition to the restructured industry, we foresee a significant shift in the role of this Commission. As regulators of monopoly utilities, we served in part as a surrogate for the pressures of a competitive market; with the arrival of competition in the generation function of the vertical utility, the need for regulation will evaporate. As this market evolves, so will our roles. We expect to continue to pursue the public interest by monitoring the transition to the restructured industry and taking any steps necessary to react to undesirable developments. We also will continue and expand our role of providing protection, safety and information to consumers, and to provide a forum for resolution of customers' complaints about all aspects of electric service. We will also act to see that fairness prevails in the competitive industries established by this decision and that the conditions necessary for fair competition are present. Below, we elaborate on some of these roles.

1. Safeguards

Today we take steps to restructure the electric industry in ways that have not been fully tried or tested before. We know that we cannot anticipate every problem or prevent every adverse outcome that may occur, but it is only prudent to think about how we should react to unforeseen developments.

We can think of two situations in which we might be called on to take corrective action. First, parties might seek a mid-course correction to refine and adjust the market mechanisms instigated today. Second, a need could arise for more substantial action to counter significant adverse developments that threaten to negate the benefits of our reforms.

In either situation, we must be able to monitor the market and detect if and when the restructured industry deviates significantly from our goals of maintaining a robust and fair market, effectively controlling market power, and ensuring a fair distribution of the benefits of competition. We need to retain the ability to intervene and counter significant adverse developments in order to preserve and promote the reforms we institute today. Intervention in the market to make such adjustments should not be taken lightly or initiated too quickly: a lesser level of competition than expected or lower than expected benefits are not necessarily the sort of significant adverse consequences that need correction if the market is otherwise functioning reasonably well.

Before we would make any corrective interventions, we would need an ability to recognize and distinguish between a minor problem or merely disappointing results and significant adverse consequences that require our intervention. This is another area where the active participation and cooperation of the affected parties will help us recognize significant problems as they arise and to craft appropriate solutions.

In addition, we will devise measurement criteria to help us detect and correct any emerging problems in the new industry structure. In our restructuring of the telecommunications industry, we established regulatory goals and a system to evaluate and respond to signals promptly. (See D.89-10-031, 33 CPUC 2d 43, 194-200.) We will need similar monitoring criteria that are appropriate for the electric industry. Our criteria should be consistent with any criteria FERC may impose. We propose to monitor developments using these criteria, and we will not undertake any intervention unless it is shown to be absolutely necessary. Our proposed roadmap will establish the procedure for parties to help us develop these criteria.

Even before the transition to competition begins, the CEQA review and market power analyses may present us with identifiable adverse impacts. We will act on the results of those studies after we have received and reviewed them.

2. Consumer Protection

UCAN and the Greenlining Institute point out that neither of the May 1995 proposals addressed the increased need for education of consumers, particularly small consumers, under the new market structure. They note that consumers have been particularly vulnerable to fraud in other newly deregulated industries and propose that the Commission address this concern by establishing an independent education trust modeled after the Telecommunications Education Trust. The purpose of this proposed trust is to ensure independent, multicultural education, advocacy, and research for small business and residential customers. According to the Greenlining Institute, many parties, including PG&E and Edison, have supported the principle of an independent education trust. The Framework Parties echo this suggestion and propose to augment the Commission's consumer affairs staff to improve the Commission's ability to resolve consumer complaints and enforce rules for market conduct. We would like to explore further these general principles during the implementation phase.

Based on our experience in the telecommunications industry, we realize that consumers will need information about the changes occurring the electric services industry and how rates are affected. From our ongoing efforts to internally reorganize the Commission, we know that we will be redesigning this component of the Commission to strengthen and provide greater service. In the short run, we expect to conduct customer education, with special attention to ensuring that customers, especially those with limited English-speaking ability or other disadvantages when dealing with sophisticated marketers, receive correct, reliable and easily understood information to help them make informed choices. We will develop this approach more fully in our procedural roadmap.

3. Registration

Our consumer protection role may be enhanced if we retain the ability to require energy service providers, including marketers, brokers and aggregators, to register with or obtain a license from this Commission. Before imposing even a minimal requirement, we will carefully consider whether existing commercial safeguards embodied in the California Department of Consumer Affairs or the Federal Trade Commission are sufficient to protect consumers in the restructured electric services industry. We intend to pursue this issue of registration or licensing during our roadmap implementation phase.

FINDINGS OF FACT

1. Performance based ratemaking (PBR) promotes desirable utility behavior by rewarding efficient performance.

2. The real-time and time-of-use rate options give customers the ability to reduce their electric bills by shifting their consumption of electricity to off-peak periods when prices are lower.

3. Vertically integrated utilities own and control a majority of generation, transmission, and distribution assets serving the California market.

4. The establishment of an independent system operator (ISO) lessens the potential for owners of the transmission system to favor their own generation facilities over nonutility facilities in providing transmission access.

5. Separation of the ISO and the Power Exchange:

- prevents the ISO from favoring pool transactions over transactions occurring outside the pool or from unfairly restricting the operation of nonpool suppliers in case of grid congestion;

- provides transparent information about system operations and congestion;

- aids in eliminating any perception of discriminatory decision making;

- eliminates the perception and the real possibility that the ISO could gain financially by preferring one supplier over another in dispatching generation and scheduling transmission.

6. The mechanisms and protocols for the ISO and Exchange that we suggest demonstrate that our policy goals are attainable, but do not forestall other suggestions or means that achieve the same goals.

7. In California there exist transmission bottlenecks or constraints that might affect the choice of which generators will actually be dispatched.

8. Pricing actual transmission usage at the difference in the locational marginal costs determines fair and efficient use of available transmission without cost-shifting.

9. Transparent information flow is critical to ensuring equal access to transmission capacity.

10. From the perspective of end users, participation in the Exchange is voluntary as soon as the Exchange begins.

11. If the utilities opted to make the bulk of their purchases on behalf of full service customers through bilateral contracts, those customers most vulnerable to an abuse of market power would have no means of tracking the cost of the electric power.

12. During the transition period, the participation of the jurisdictional utilities in the Power Exchange will lessen regulatory burdens associated with assets that are non-competitive in a transparent market, ensure that customers that rely upon the distribution utility for procurement receive the benefits of competitive market prices, and provides sufficient depth to the Exchange that its market signals may be relied upon as benchmarks for customer choices.

13. Contracts for differences are private agreements that allow the buyer and seller to allocate the risks associated with market uncertainty and are a way for the customer to hedge the cost of electricity over time.

14. Allowing the aggregation as well as the individual participation of small commercial and residential customers is vital to ensuring that all consumers have the opportunity to participate and benefit from consumer choice.

15. If customer information is provided exclusively to the utility-affiliated generating company, it could give that company an unfair advantage over other competitors.

16. Over a twenty-four hour period the demand for electricity varies dramatically.

17. The revelation of the real-time price of electricity coupled with a rate alternative that allows the customer who is able to respond intelligently will produce savings for any customer who is able to shift demand from peak to off-peak hours and will produce a collective benefit, in that demand will be redistributed away from the current peaks. Future generation demands will be forestalled even as existing investments in generation are made more productive.

18. Transparent, reliable price signals will be very important to foster a competitive market during the transition period because customers and suppliers will develop sophistication over time and alternative resources for price information will develop over time.

19. Existing cost-of-service regulation has become too complex and difficult in many ways to allow us to regulate the utilities properly in this fast-moving industry. Cost-of-service regulation is no longer compatible with the changing electric industry and is in need of reform.

20. PBR offers flexibility and encourages utilities to focus on their performance, reduce operational cost, increase service quality, and improve productivity. PBR mechanisms should be designed to ensure that safety, quality of service, and reliability are not compromised.

21. By providing financial incentives to utilities through PBR, we will encourage them to operate more efficiently to maximize their profits.

22. The cost of electricity in our state is about 50% above the nation's average rate.

23. Competition in the electricity market will deliver desirable market characteristics that have not been delivered by the regulated market regime of the past.

24. The abuse of market power reduces the societal efficiencies of competition.

25. A competitive market mitigates market power abuse by means of contestibility.

26. A market structure that brings generation competitors into the market and eliminates barriers to entry will reinforce industry contestibility.

27. Control of vertically integrated assets results in barriers to entry if an entity at one stage of the production and delivery process gives preferential treatment to an affiliated entity operating at another stage of the production and delivery process.

28. Provision for an ISO and independent dispatch results in an *operational unbundling*, in which vertically integrated electric processes are separated and operational control is spread among entities that are independent of the owners of assets in other levels of the chain of production.

29. Utility control of both energy procurement and generation functions might result in vertical market power.

30. Market power can take place at any level of the production chain if there are significant barriers to entry or few market participants.

31. Concentrations of ownership or control of generation facilities can result in market power because a single competitor might control enough assets to alter the supply-demand equilibrium and thus be able to increase prices by withholding generation from the market (decreasing supply).

32. The most direct approach to mitigating market power resulting from concentrations of generating facility ownership is disaggregation of concentrated assets.

33. In an environment where utilities participate in both the regulated and unregulated sides of an industry, a utility might attempt to use funds from its stable and profitable regulated business to gain an advantage in its unregulated businesses through cross-subsidies.

34. Disaggregation is the most effective way to prevent cross-subsidies.

35. Divestiture of the utility's competitive generation assets from its regulated assets is the only structural option which will completely eliminate the utility's ability to engage in improper cross-subsidization.

36. The existence of strategically located assets creates a threat of market power that cannot be mitigated by disaggregation.

37. Net book value means the original cost recorded in the company's books for a particular asset less any accumulated depreciation and adjusted for deferred taxes, and any other asset or liability account which relates to the asset.

38. Many of the high costs of today's electricity result from past regulatory promises made by the Commission regarding the timing of the recovery of depreciation and taxes, past requirements to diversify sources of power by signing long-term contracts that in hindsight have high costs, and the costs incurred by utilities that were reviewed and deemed reasonable when incurred.

39. The competitive market will classify utility generation assets as either economic or uneconomic.

40. A utility asset is uneconomic if its net book value exceeds its market value, and an asset is economic if its market value exceeds its net book value.

41. For a particular utility, its transition costs are the net above-market costs associated with its assets, both economic and uneconomic.

42. Transition costs arise when a plant is unsuccessful in its bid to supply power through the Power Exchange, because if it is unable to sell its power, it has no opportunity to recover its fixed investment costs. Even if a plant is a successful bidder into the Power Exchange, transition costs will also accrue if the market-clearing price paid to successful bidders is too low to allow recovery of the plant's fixed costs.

43. To the extent Diablo Canyon settlement prices are above the prices in the market, as revealed by the Power Exchange, this plant will be uneconomic.

44. QF contract prices may be above the Power Exchange's revealed market prices, and thus the contract will be uneconomic.

45. Prices under utilities' contracts with wholesale providers may be higher or lower than the market price. These contracts may either be uneconomic, increasing transition costs, or economic and available to offset other uneconomic costs.

46. The premium associated with economic assets should be offset against the excess costs of uneconomic assets to reduce the overall level of the utility's transitions costs.

47. Under the current regulatory structure, ratepayers have prepaid income taxes associated with some generation assets.

48. Under the current regulatory structure, we have granted utilities monopoly franchises to provide electricity to the consumers in their service territories, and we have required utilities to provide reliable service on a nondiscriminatory basis to all customers within their territories who requested service. In fulfillment of these responsibilities, utilities developed a portfolio of generation assets by investing in power plants and entering into purchase agreements.

49. Maintaining the financial integrity of the utilities is an important goal of this proceeding.

50. If we do not provide for adequate transition cost recovery, the move to competition may threaten the utilities' financial stability.

51. Assurance of full recovery gives the utility no incentive to minimize transition costs.

52. If the utility is indifferent to the level of transition costs, it would in turn have an incentive to bid low in offering its generation assets’ output to buyers in the Power Exchange, with the foreseeable effects of depressing the market-clearing price, squeezing the profit margins of competitors, and further increasing transition costs.

53. Recovery of the transition costs significantly lowers a utility’s risk of recovery, because once an asset is market-valued, the utilities will not be subject to the risk that the plants will be found no longer to be used and useful.

54. Applying a reduced rate of return to transaction costs benefits ratepayers because it reduces the transition cost revenues associated with generation plants from the levels that ratepayers would otherwise pay in rates under cost-of-service ratemaking and reduced revenues will also reduce taxes that would otherwise be reflected in rates.

55. By lowering the return on transition costs, we will create an incentive for the utility to minimize transition costs and avoid the undesired consequences associated with full cost recovery.

56. Rate reductions continue to be a primary goal of this proceeding.

57. The rate impacts of transition cost recovery can be mitigated somewhat by a policy of capping rates at the level in effect as of January 1, 1996, without adjustment for inflation.

58. Reducing the return on investment-related transition costs will provide utility management with an incentive to minimize the level of transition costs, and as a result to reduce rates.

59. A market-based approach to calculating transition costs associated with utility assets will produce superior results to an administrative approach.

60. The market value for a sale or spinoff of an asset may be calculated by the sale price, or the stock market value of shares issued to effect a spinoff.

61. Both QFs and utilities may have an incentive to renegotiate their contracts.

62. An approach that involves both a monetary incentive to shareholders and conditions which foster voluntary, nonstandard negotiations will promote renegotiation of QF contracts.

63. The transition costs that arise from regulatory obligations are related to various deferred costs and outstanding balancing account balances the utility has accrued under cost-of-service regulation.

64. If the utility retains ownership of the nuclear facilities after market valuation, it should recover the costs for the decommissioning trust fund.

65. Market valuation of assets through an appraisal approach will provide results superior to an administrative approach because the appraisal approach relies on independent industry experts rather than experts hired to support each party’s position, as is common in regulatory proceedings.

66. Concentration of generation ownership in utilities remains a serious unmitigated market power concern.

67. In the MegaNOPR, the FERC proposed that utilities be entitled to recover legitimate and verifiable stranded costs from increased competition in and entry to the wholesale market.

68. Different utilities will have different transaction costs.

69. The recovery of transaction costs should apply to sales to both direct access and utility service customers on a utility service territory basis.

70. Transition costs should be allocated to all customer classes using an equal percentage of marginal cost (EPMC) methodology, unless specific circumstances justify a different approach.

71. Transition cost recovery should not increase the price for electricity, on a kWh basis, above current rate levels in effect as of January 1, 1996, without adjustment for inflation.

72. California's electric utilities have a long history of participating in activities that assist many California citizens.

73. The continued reliance on utilities to achieve social goals may put the utility at a disadvantage in the move toward a more market-based, customer-oriented electric services industry. Subjecting utilities to the cost of programs that their competitors do not bear is not a sustainable strategy.

74. The present mix of renewables on the system has been driven by resource diversity interests on the part of utilities and the Commission’s QF policy, which encouraged the growth of independent power production during the 1980s.

75. The Commission's recent policy of encouraging resource diversity through the development of new renewable resources is derived from §§ 701.1 and 701.3.

76. A program of tradeable credits for meeting a minimum renewables purchase requirement will allow buyers and sellers to search the market for the best renewables bargains and to internalize such costs in their prices without the need for a surcharge to fund renewables development.

77. Tradeable credits for meeting a minimum renewables purchase requirement allow retail providers the most flexibility in meeting this requirement.

78. In a restructured environment, evaluating cost-effectiveness on the basis of utility resource deferral may no longer be relevant.

79. Electric utility RD&D programs today support both regulated business functions and public purpose goals.

80. After restructuring, a utility will still have a need to conduct research to support its continuing monopoly functions.

81. Research that serves a broader public interest and that may not be pursued by the monopoly should not be lost in the transition to a more competitive environment.

82. Low-income assistance has limited rate impact.

83. To implement § 8281 et seq., General Order (GO) 156 initiated the WMDVBE program in 1987, and established goals for regulated utilities' procurement practices. The goals encourage awards of not less than 15% of all contracts for goods and services to minority-owned businesses and not less than 5% to women-owned businesses. Following a 1990 amendment to the Public Utilities Code, GO 156 was expanded to include disabled veteran-owned businesses.

84. In PG&E's recent Rate Design Window proceeding, we adopted PG&E's proposal that until there is direct access, costs associated with rate discounts should be split between ratepayers and shareholders; once restructuring is in place, 100% of the costs will be borne by shareholders (D.95-10-033).

85. The existence of ERAM gives a utility little incentive to rigorously negotiate the smallest discount necessary to retain a specific customer, because ratepayers effectively compensate the utility for the amount of the discount.

86. Section 740.2 requires the Commission to encourage energy utilities to conduct research on electric and natural gas vehicles, and § 740.3 requires the Commission to implement policies to promote and facilitate development of equipment and infrastructure for low-emission vehicles. Section 740.3 also provides for the recovery in rates of costs incurred in the ratepayers' interest.

87. Utility customers, unlike nonutility customers, are able to benefit from LEV expenditures directly through their eligibility for utility LEV programs.

88. Undergrounding is carried out by the utilities under a tariffed program.

89. Undergrounding is a program that the cities and counties of California rely upon as part of their local improvement efforts.

90. In the absence of a finding that a project is exempt, the California Environmental Quality Act requires state agencies to evaluate the environmental impacts of any discretionary project they approve. Further, if an agency determines that a project may have a significant effect on the environment, it must prepare an Environmental Impact Report (EIR).

91. Consumers have been particularly vulnerable to fraud in other newly deregulated industries.

CONCLUSIONS OF LAW

1. Our goals in this proceeding are:

   - to offer consumers greater choice in their purchases of energy services.
   - to allow competition for traditional monopoly services to flourish where conditions are ripe.
   - to transform our oversight of industry segments that are not subject to competitive pressures to performance-based ratemaking.
   - to reduce the price California consumers pay for electricity.
   - to continue to deliver safe, reliable, and environmentally sensitive energy services.
   - to maintain universal, nondiscriminatory availability of electric services to all citizens of this state.
   - to maintain the financial integrity of the utilities and provide utilities with a reasonable opportunity to earn a fair return on their investments.
   - to continue to further the public good, as perceived by the Legislature and this Commission, by improving the environment, encouraging the diversity of energy sources, and maintaining a variety of important public purpose programs.

2. In obtaining generation services, consumers should be able to choose:

   - to contract for generation services, on whatever terms both parties find acceptable, directly with generators or marketers of generation services.
   - to aggregate their load with others' to increase their purchasing power.

- to continue to receive generation services from the utility and pay either average cost-based rates or rates based on the prices of the Power Exchange.

3. The creation of the ISO and the Power Exchange requires exercise of jurisdiction by both this Commission and the FERC under a policy of cooperative federalism.

4. The FERC must approve the rates, terms and conditions of transmission services provided by the ISO.

5. The vertically integrated electric utility is not compatible with the institutions of a competitive market for electric services. It is necessary to disaggregate the vertically integrated electric utility by separating the elements of generation, transmission and distribution.

6. The functions of the ISO and the Power Exhange should be vested in separate entities, wholly independent of one another.

7. The ISO shall have no financial interest in any source of generation or load, no ownership affiliation with any companies that own those facilities, and no financial interest in the Power Exchange.

8. The ISO shall have the following responsibilities and functions:

- to control the operation of the transmission facilities, oversee transmission activities, and be responsible for providing efficient, reliable service.
- to coordinate day-ahead scheduling and balancing for all users of the transmission grid.
- to provide open and nondiscriminatory access to the transmission grid.
- to determine marginal cost prices, differentiated by location and time, that will apply for purposes of transmission pricing and managing congestion to all users of the transmission system.
- to administer a system of transmission congestion contracts.

- C to procure ancillary services needed to support transmission and dispatch.
- C to provide comparable service to all users of the transmission system.
- C to honor existing transmission contracts.
- C to submit protocols to the FERC for transmission congestion management based on simplicity, practicality, and efficiency.
- C to ensure that adequate generation capacity is available to maintain frequency and to manage generation and load fluctuations.
- C to make system data available quickly and on a comparable basis to all market participants.

9. Fairness dictates honoring existing QF contracts and other existing wholesale power purchase agreements as we move toward a more competitive market.

10. The utility has an obligation to administer its existing QF contracts and existing wholesale power purchase agreements in the best interests of its customers and in a manner that maximizes systemwide benefits and minimizes transition cost accrual.

11. The ISO shall be indifferent, for purposes of resolving the transmission congestion, to the source of generation affected by the constraint.

12. The resolution of transmission congestion shall be open, fair, nondiscriminatory, and efficient.

13. In the market structure we adopt today, the suppliers and their intermediaries (including the utility in its procurement role) have the responsibility to match the dispatch of electricity supply with expected customer load according to the terms of their retail or wholesale contracts.

14. The interests of all Californians requires the creation of a transparent, visible spot market for electric generation.

15. The Power Exchange shall implement nondiscriminatory rules which will permit rival generators to compete on common grounds using transparent rules for bidding into the Exchange.

16. The Power Exchange shall have no financial interest in any source of generation to ensure that it will have no bias in favor of or against specific generators. The Power Exchange shall be prohibited from owning generation, transmission or distribution facilities and should have no affiliation with any companies that own those facilities. The Power Exchange shall have no financial interest in or ownership ties to the ISO.

17. The Power Exchange shall oversee the ranking of least-cost generation facilities according to established protocols.

18. During the five-year transition period jurisdictional utilities shall be obligated to sell their generation into the Power Exchange and make purchases of electric power needed to supply the needs of their full service customers from the Exchange.

19. During the transition period customers who elect to rely upon a jurisdictional utility to procure electric power as well as distribution services shall be billed by that utility at its cost of purchases from the Power Exchange. At the full service customer’s option that bill shall be calculated either on an average cost to the utility for Exchange purchases made during the billing cycle or, if there is appropriate metering equipment, in a calculation in which the Power Exchange price is matched against the time of use in which the customer’s consumption occurred.

20. If a jurisdictional utility divests itself of a generation asset to an unaffiliated entity, the subsequent participation of that asset in the Exchange is entirely voluntary on the part of the new owner.

21. Allowing juisdictional utilities to opt for non-Exchange purchases and sales during the transition period disguises pricing information, limits customer choice, and requires contentious regulatory proceedings to validate the dimension and legitimacy of the competition transition charge.

22. The Federal Power Act confers exclusive jurisdiction over rates, terms, and conditions for sales for resale (wholesale sales) on the FERC.

23. Retail sales, even if the power originates out-of-state, are subject to exclusive state jurisdiction.

24. State authority to review reasonableness of wholesale power purchases where a utility has procurement alternatives is firmly established.

25. Customers in all classes should have a fair opportunity to participate in each phase of direct access.

26. Aggregation may include the loads of multiple customers, or a customer may aggregate loads at several sites. Aggregation should be voluntary.

27. Intermediaries will be able to purchase unbundled electricity from individual suppliers and bundle that power with various energy services to meet the customers' needs.

28. Suppliers or third-party intermediaries may install metering equipment on behalf of a customer so long as the meter meets standards adopted for the distribution utility.

29. Utilities will continue to control and operate their distribution system, to own and operate their generation assets (subject to some incentives for divestiture), and to procure generation services for their energy service customers. They will also continue to own, but not operate, their transmission facilities.

30. We will prohibit power purchase contracts and contracts for differences between the distribution utility and its affiliated generating companies.

31. The utility distribution company (UDC) has an obligation to provide distribution services to all customers. The UDC will no longer be obligated to plan for or provide generation service to direct access customers.

32. Municipal utilities in California who wish to compete to sell power to retail customers of the investor-owned utilities should provide reciprocal access to customers in the municipal service territories.

33. Utility property, such as a generation asset, that has received revenue recovery through rates is used and useful in the performance of the utility's duties to the public until such time as the Commission determines otherwise. The act of market valuation is not itself sufficient to release the property from its dedication to public use.

34. We cannot have a fully competitive market for generation unless and until we eliminate any significant lingering ability of the former monopoly utility to distort prices or restrict competition in the new competitive market.

35. To ensure contestability in the generation market, we should eliminate any undue competitive advantages to existing firms and eliminate barriers to entry of prospective competitors.

36. Contracts between utility-affiliated generators and the distribution utility should be prohibited.

37. Transition costs should be collected in a manner that is competitively neutral, is fair to all classes of ratepayers, and does not increase rates.

38. The netting of economic and uneconomic assets is a partial way of compensating ratepayers for the loss of continued dedication to public use of economic assets.

39. It would be obviously unfair if, as part of our restructuring, we were to require customers to pick up the costs of high-cost generation without at the same time accounting for the benefits of low-cost generation.

40. The calculation of transition costs should account for prepaid and unpaid deferred taxes related to generating assets.

41. It is fair to compensate the utilities for reasonable investments in needed plants that cannot be effectively recovered in a competitive market.

42. We should develop a process to account for the lingering effects of the regulated market structure during the transition to competition.

43. It is fair to allow utilities to recover capital investments in generating plants and contractual obligations.

44. Utilities should be allowed to recover an appropriate amount of transition costs.

45. Ratepayers should benefit, at least to some degree, from our treatment of transition costs.

46. The principles that ratepayers should benefit from our treatment of transition costs and that utilities should have proper incentives can be accommodated in a recovery mechanism that reduces the return on investment-related transition costs.

47. Ratepayers should not be required to pay utilities all of the revenues they would have recovered in the absence of this reform effort.

48. It is fair to pay shareholders a lower rate of return which appropriately reflects the reduced risk for generating assets.

49. Our approval of rate recovery for the reasonable costs associated with generation plants and other obligations incurred under a regulated industry structure does not mean that customers must produce the same revenues under the new regulatory structure. We are required only to design a rate structure the total impact of which provides the utilities with the opportunity to earn a fair return on their investment.

50. The overall market structure proposed today, including the utilities' recovery of a large portion of transition costs and the opportunity to earn profits in a competitive market, provides shareholders with an adequate opportunity to earn a fair return on their investments.

51. Shareholders should not completely avoid responsibility for costs related to facilities that changing circumstances have made uneconomic.

52. Negotiations for a sale of a utility asset should be conducted at arm's length and the resulting sale price should be generally consistent with other market information.

53. Recovery of retail transition costs should be subject to state jurisdiction. Under the Federal Power Act jurisdiction over retail transition costs lies exclusively with state authorities.

54. Direct access customers should be required, as a condition of the utility's retail distribution tariff, to sign an agreement to pay their share of transition costs and thereby waive any jurisdictional objection they might otherwise raise in any forum.

55. Utilities should be required to modify the Preliminary Statement of their tariffs to provide all current and new customers with notice of our intent to authorize collection of retail transition costs.

56. Using marginal cost pricing for electric services using the EPMC methodology for the allocation of transition costs ensures a fair allocation among all customer classes and prevents inter- and intraclass cost-shifting.

57. The competitive transition charge (CTC) should be assessed on all customers who are retail customers on or after the date of this decision, whether they continue to take bundled service from their current utility or pursue other options.

58. To assure the continued financial integrity of the utilities, and give them an opportunity to be vital market participants in the restructured market following the transition, utilities should recover 100% of CTC.

59. Only regulatory assets related to generation should be included in CTC.

60. Prior to market valuation, fossil fueled generating units should recover 100% of undepreciated, book value.

61. Return levels for CTC associated with fossil fueled units will be set at the embedded cost of debt for the debt portion and 90% of the embedded cost of debt for the equity portion.

62. Operating costs and capital costs not yet incurred for fossil fueled generating units are not eligible for CTC recovery unless the unit is needed for reactive power/voltage control, market based prices for those services are not yet established, and the amounts requested are subject to PBR.

63. If the Exchange clearing price exceeds the costs of running fossil fueled generating units, utilities should be able to earn up to 150 basis points above their authorized return for distribution rate base before additional profits are used to reduce CTC.

64. Hydroelectric and geothermal generating units should remain subject to rate of return regulation and provide their output to the distribution function of the utility through the Exchange, and will be subject to PBR.

65. Revenues from the Exchange in excess of revenue requirements for hydroelectric and geothermal gnerating units should be used to reduce CTC.

66. It is reasonable to adopt 90% of the embedded cost of debt as a reasonable rate of return on the equity portion of the net book value of fossil fueled generation units to reflect the reduced risk. It is reasonable to provide an incentive to the utilities to voluntarily divest their fossil fueled generation assets by granting an increase in the rate of return for the equity component of up to 10 basis points for each 10% of fossil generating capacity divested, provided we have resolved any locational market power concerns associated with the unit and authorize the transfer pursuant to § 851.

67. Separate sub-accounts will be used for CTC so that return levels are set appropriately for different assets.

68. The CTC account will be annually adjusted to reflect Exchange clearing prices and to reflect assets that received market valuation.

69. With the exception of CTC arising from existing contracts, no further accumulation of CTC will be allowed after 2003 and collection will be completed by 2005.

70. Given the accelerated depreciation schedule allowed for the SONGS nuclear plants, it is fair to set the rate of return at the embedded cost of debt for the debt share of the utility's capital structure associated with these assets, and at 90% of the embedded cost of debt for the remaining share (equity).

71. Section 455.5 continues to apply to outages of utilities' generating plants that are out of service.

72. The short-run avoided cost energy payments to QFs should be set at the Exchange's clearing price as soon as we are confident the Exchange is functioning properly.

73. Modification of QF contracts will follow our existing principles that the modifications are voluntary on the part of the QF, should reflect ratepayer benefits relative to the most probable stream of payments for that QF without the modification, and should benefit from the flexibility that nonstandard, arm's length negotiations have previously revealed.

74. When a QF contract is renegotiated, shareholders should retain 10% of the resulting ratepayer benefits, which will be reflected by an adjustment to the CTC if the modification is approved by the Commission.

75. Utilities should be allowed to earn a premium, related to the transition costs of fossil plants, based on fossil plants that are sold or spun off to unaffiliated entities.

76. Some ongoing costs, if not recovered from the Exchange, might make a smooth transition to a restructured market difficult: the location of certain non-nuclear generating units provides reactive power/voltage control to the transmission grid and market-based prices or mechanisms for that ancillary service are not yet established.

77. Under the Federal Power Act jurisdiction over retail transition costs lies exclusively with state authorities.

78. The need for public purpose programs will continue after restructuring.

79. Restructuring policies should maintain California's resource diversity for existing resources and encourage development of new renewable resources.

80. The minimum renewables requirement approach will allow the market to provide the most cost-effective renewable resources, without our intervention.

81. Allowing providers to trade in order to meet the renewables requirement may also serve to minimize the stranded costs associated with existing QF contracts by providing new markets for QFs' power.

82. The focus of publicly funded energy efficiency programs should shift to those programs in the broader public interest, for example, programs with market transformation effects and education efforts that would not otherwise be provided by the competitive market.

83. Customer-specific energy efficiency projects should not require future funding from ratepayers, but should instead rely on market-driven funding mechanisms.

84. Continued funding is appropriate for activities that are designed to transform the energy efficiency market and will not naturally be provided by a competitive market.

85. By January 1, 1997, energy efficiency costs should no longer be embedded in electric rates and instead should be collected as part of the public goods charge applied to retail electric sales.

86. Until public funding for DSM activities is removed from rates and collected through a surcharge, an ERAM-type mechanism should be retained to account for energy efficiency impacts.

87. The remaining monopoly utility should no longer use ratepayer funds for generation RD&D.

88. The PGC should collect funds for public goods research only, not funds for regulated or competitive research functions. The monopoly utility should no longer collect ratepayer funds for generation-related research as of January 1, 1997.

89. The PGC should not collect funds to pursue research that the competitive market will provide on its own.

90. By January 1, 1997, the public goods RD&D costs should no longer be embedded in electric rates and instead should be collected as part of the PGC applied to retail electric sales.

91. Until further action by this Commission, all electric service providers under our jurisdiction should be required to offer eligible customers baseline service consistent with § 739.

92. Low-income assistance costs should be recovered as a surcharge on electricity use separate from other public goods charges.

93. Funding for low-income rate discounts recovered through a surcharge should not be capped at current levels but should instead be based on need.

94. CARE funds should be used for a customer discount that appears on the bill rather than an after-the-fact refund or rebate.

95. No additional funding or changes to the WMDVBE program are needed for the program to go forward after industry restructuring.

96. Sections 740.4 and 740.7 allow for funding of utility economic development activities to the extent of ratepayer benefit.

97. Our existing guidelines on funding requests for utility economic development programs are adequate.

98. Generation and related procurement outside the Power Exchange by the regulated utility should be subject to WMDVBE statutes and GO 156, just as fuel procurement is today.

99. Revenue shortfalls resulting from new rate discounts offered to avoid customer bypass, attract new business, or retain existing or expanding businesses should be shared until 1998 between ratepayers and shareholders.

100. Once the restructured market has begun in 1998, utilities will not be able to pass the costs of discounts to ratepayers; instead, shareholders should fund any discounts offered to customers.

101. The costs of utility LEV programs should continue to be collected by the regulated utility and identified as a line item on customer bills, as opposed to being collected as part of the PGC.

102. Undergrounding remains an appropriate activity of the regulated utility, not subject to competition, and therefore its costs should be collected through regulated utility rates.

103. The sheer scope controversy of our proposed electric policy favors reviewing the possible environmental impacts of a new industry structure.

104. Preparation of an EIR as opposed to a negative declaration is appropriate in the instant proceeding, because it cannot be seen with a certainty that our proposal will not have an adverse effect on the environment.

105. The restructuring proceeding has an identified potential to impact the environment.

106. An EIR will be prepared for our preferred policy proposal.

107. An initial environmental study is not required.

108. Because we are embarking on the environmental review process, none of the policy proposals in this decision are final. Today's decision constitutes the Commission's identification of preferred policy and the project proposal, which cannot be finally adopted or approved until after we have prepared the EIR and considered its findings.

109. Based on our experience in the telecommunications industry, it would be prudent to establish an independent education entity before the onset of customer choice.

110. Our consumer protection role will be enhanced if we retain the ability to require energy service providers, including marketers, brokers and aggregators, to register with or obtain a license from this Commission.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall work together and with other parties to develop a detailed proposal for submission to the Federal Energy Regulatory Commission (FERC) to establish the independent system operator (ISO) and its protocols and transfer operational control of the utilities' transmission facilities to the ISO. This proposal shall be filed at FERC and simultaneously filed and served in this docket within 130 days after the effective date of this decision. The proposal shall comply with the principles and guidelines for operational issues outlined in Chapter III of this decision and shall include recommendations for ownership, financing, and corporate structure of the ISO.

2. If parties wish to comment on the proposals set forth in Ordering Paragraph 1, they shall file and serve opening comments in this docket no later than 160 days after the effective date of today's decision. Parties shall file and serve reply comments no later than 175 days after the effective date of today's decision.

3. PG&E, SCE, and SDG&E shall work together and with other interested parties to prepare a joint proposal to establish the Power Exchange. This proposal shall follow the policy guidance described in Chapter III and shall include recommendations which address the ownership, financing, corporate structure, pricing mechanisms, and bidding protocols of the Power Exchange. In addition, the proposal shall address communications with the ISO and additional Power Exchange responsibilities, as discussed in Chapter III. PG&E, SCE, and SDG&E shall include recommendations for the ownership, organizational structure, and working capital of the Power Exchange in their proposal. The joint proposal shall be filed at FERC and simultaneously filed and served in this docket no later than 130 days after the effective date of this decision. If parties are unable to agree on a joint proposal, PG&E, SCE, and SDG&E shall

file and serve individual proposals in this docket; these proposals shall address the issues outlined above and be filed and served no later than 130 days after the effective date of this decision.

4. Parties may file comments on the proposal set forth in Ordering Paragraph 3 or file proposals of their own. These comments shall be filed and served no later than 160 days after the effective date of this decision. Reply comments shall be filed and served no later than 175 days from the effective date of this decision.

5. For the five-year transition period during which PG&E, SCE, and SDG&E seek recovery of their stranded generation assets and power purchase liabilities, each utility shall bid all of its generation into the Power Exchange and procure electric energy for its full service customers by purchases from the Power Exchange. During the transition period, any generation unit sold by the utilities by way of divestiture to a non-affiliated new owner shall immediately be freed of any obligation to bid into the Power Exchange. At the end of the transition period, when determination of assets which qualify for recovery under the competition transition charge has been finalized, the utilities shall be released from any mandatory requirement to bid into or purchase from the Power Exchange.

6. The initial phase of retail competition, or “direct access,” shall be implemented simultaneously with the establishment of a Power Exchange and ISO. At a minimum, PG&E, SCE, and SDG&E shall phase in direct access according to the following schedule:

Total Number MW Available for Participation in Direct Access

Year	PG&E/SCE	SDG&E
1998	800	200
1999	1,400	350
2000	2,200	550

Year	PG&E/SCE	SDG&E
2001	4,000	1,000
2002	8,000	2,000
2003	All remaining load	All remaining load

PG&E, SCE, and SDG&E shall confer with interested parties to recommend proposals for direct access, including eligibility parameters in the initial phase of direct access, consistent with the principles outlined for direct access and real-time and time-of-use rate options. The proposals shall include recommendations for eligibility parameters for the transition phase and beyond. These proposals shall be filed and served in this docket no later than 30 days from the effective date of this decision. Comments on these proposals may be filed and served within 60 days of the effective date of today's decision. We ask parties to carefully consider whether a continued phase-in schedule is necessary or whether eligibility can be held open to all electricity consumers sooner than five years. Reply comments may be filed and served no later than 75 days from the effective date of this decision.

7. PG&E, SCE, and SDG&E shall not enter into retail contracts to purchase the output of a generation facility that is under their own or any of their affiliates' ownership.

8. PG&E, SCE, and SDG&E shall retain its obligation for least-cost procurement for utility service customers, that is, those who do not elect to procure their own electricity supplies. Least-cost procurement obligations shall be met by purchases through the Power Exchange.

9. PG&E, SCE, and SDG&E shall provide distribution services to direct access customers, but shall no longer be obligated to provide generation services to those customers.

10. We authorize PG&E, SCE, and SDG&E to provide delivery services to direct access customers, under tariffs approved by both FERC and this Commission upon written agreement by the direct access customers to pay their share of retail transition costs, as determined by this Commission.

11. As of January 1, 1998, the distribution utilities shall offer tariffed electric service which references the real-time market clearing price as published by the Power Exchange.

12. PG&E, SCE, and SDG&E shall adhere to the following schedule for meter installation for customers other than those who are categorized within the Domestic, GS-1, and TC-1 customer groups:

Maximum Demand	Installation
500 kW	by 1998 when restructuring begins
400 kW	one year after restructuring begins (at least by 1999)
300 kW	2 years after restructuring (at least by 2000)
200 kW	3 years after restructuring begins (at least by 2001)
100 kW	4 years after restructuring begins (at least by 2002)

13. PG&E, SCE, and SDG&E shall not enter into contracts for differences (CFDs) with their own generation facilities or their affiliated generation facilities.

14. Within 30 days of the effective date of this decision, parties shall file and serve comments in Application (A.) 93-12-029 on whether SCE's pending performance-based ratemaking (PBR) proposal should be amended or not.

15. Within 30 days of the effective date of this decision, parties shall file comments in A.94-03-008 on whether PG&E's pending PBR proposal should be amended or not.

16. We direct the parties to file and serve comments in A.94-01-016 addressing how SCE's proposed Gas Cost Incentive mechanism is impacted by today's decision. These comments are due within 30 days of the effective date of this decision.

17. Within 60 days of the effective date of this decision, PG&E, SCE, and SDG&E shall file new applications, which will be assigned new docket numbers, to establish PBR mechanisms, consistent with the policies outlined in today's decision. Each applicant shall serve all parties on its existing service list. Each application shall include a proposal for a separate distribution and generation PBR. Each application shall include a discussion of strategies to mitigate horizontal market power concerns, including the issue of transition costs.

18. No later than 90 days after the effective date of this decision, PG&E, SCE, and SDG&E shall file and serve written comments in this docket on the feasibility, timing, and consequences of a corporate restructuring premised on distinguishing their activities and assets with respect to generation, transmission, and distribution. These comments shall address a holding company structure with three subsidiaries, but the comments are not limited to this corporate structure. Any interested party may file and serve reply comments no later than 150 days after the effective date of this decision.

19. No later than 90 days after the effective date of this decision, PG&E and SCE shall file a plan to voluntarily divest themselves of at least 50% of their fossil generating assets. This divestiture must be effectuated through a spin-off or outright sale to a non-affiliated entity. Any interested party may file and serve comments on these plans no later than 135 days after the effective date of this decision.

20. Customer-specific information necessary for the distribution functions of the utility shall be made available to all competitors in the generation sector, on terms that are fair to all competitors. All generation providers, including the monopoly utility, shall obtain a customer's consent before accessing any proprietary information about that customer.

21. Transition costs, or the net above-market costs for each utility, shall be determined after offsetting the benefits associated with economic assets against the excess costs of uneconomic assets. This calculation shall also account for deferred taxes.

22. PG&E, SCE, and SDG&E shall each establish a balancing account for competitive transition costs consistent with the directives in this decision. The debt portion of investment-related transition costs shall earn a return equivalent to each utility's embedded cost of debt. Each utility shall establish subaccounts within the transition cost account for the purpose of computing the imputed debt and equity portions of the net book value for each generating asset. The equity portion of investment-related transition costs shall earn a rate of return equivalent to 90% of each utility's embedded cost of debt.

23. PG&E shall file an application within 100 days of the effective date of this decision with its proposal for ratemaking treatment for the Diablo Canyon facility that would price its output at market rates by 2003. The application shall be consistent with the principles for recovery of transition costs, as outlined in this decision, including no rate increases above the January 1, 1996 levels and shall include at least one alternative comparable to that ultimately adopted for SONGS.

24. SCE shall file an application within 100 days with its proposal for a new rate mechanism for Palo Verde, including a proposal for ratemaking treatment comparable to that ultimately adopted for SONGS for rates effective on or before January 1, 1997.

25. Until such time as a market value for utility generation assets is determined, the utilities shall recover through depreciation up to 100% of the net book value of their fossil-fueled generation units through the competition transition charge (CTC). By April 1, 1996, PG&E, SCE, and SDG&E shall each file an application to identify and value the sunk costs of their non-nuclear generation assets.

26. PG&E, SCE, and SDG&E shall file applications no later than September 2, 1996 to estimate their transition costs as of January 1, 1998. These applications shall establish the first annual proceeding to address adjustments to the transition cost balancing account. In their applications, the utilities shall make a showing that they are adhering to our established principles for transition cost collection, as described in this decision.

27. Upon market valuation of an asset, PG&E, SCE, and SDG&E shall file an application pursuant to Public Utilities (PU) Code § 851 application to initiate review of the market price, transfer of the asset, and removal of the costs from the PBR benchmark and the CTC balancing account.

28. Transition costs shall be collected through the competition transition charge (CTC) which shall apply to sales to both retail procurement and utility customers on a utility service territory basis. Within 45 days, each utility shall file an advice letter to modify the Preliminary Statement of its tariffs to provide all current and new customers with notice of our intent to authorize collections of retail transition costs. Consistent with Conclusion of Law 54, each Direct Access Customer shall sign an agreement to pay their share of transition costs and thereby waive any jurisdictional objection they might otherwise raise in any forum. The CTC shall be a percentage surcharge on the bill of each customer of the distribution utility, including those served under contracts with nonutility suppliers.

29. Transition costs shall be allocated to all electric customers using the Equal Percentage of Marginal Cost (EPMC) allocation methodology. Transition cost recovery shall be capped so that the price for electricity, on a kWh basis, does not rise above rate levels in effect as of January 1, 1996, without adjustment for inflation.

30. A minimum renewables purchase requirement shall be a condition of certification. Credits for meeting this requirement shall be tradeable.

31. Upon enabling legislation, we shall establish a public goods charge. The public goods charge shall be a surcharge for energy efficiency programs related to market transformation and funding for research related to the broader public good, as discussed in this decision.

32. PG&E, SCE, and SDG&E shall retain a modified Electric Revenue Adjustment Mechanism (ERAM) account until public funding for energy efficiency is removed from rates and collected through a surcharge.

33. Unless and until we determine otherwise, all electric service providers under our jurisdiction shall offer eligible customers baseline rates, consistent with PU Code § 739.

34. PG&E, SCE, and SDG&E shall establish a surcharge to recover low-income assistance costs that is separate from other public goods charges, once the appropriate legislation is enacted. CARE funds shall be used to provide a customer discount that is reflected on each monthly bill.

35. PG&E, SCE, and SDG&E shall continue to be held to the goals established in General Order 156.

36. Funding requests for utility economic development programs shall conform to our existing guidelines, consistent with §§ 740.4 and 740.7. Effective January 1, 1997, costs authorized for these activities shall be identified as line items on customer bills.

37. For the transition period, costs associated with rate discounts shall be allocated to both ratepayers and shareholders. Once direct access is in place, shareholders shall be responsible for 100% of any costs or revenue shortfalls stemming from rate discounts offered to customers. These policies do not apply to rate discounts offered in Economic Incentive Areas or Enterprise Zones, as articulated in §§ 740.4 and 740.7. Cost-sharing allocation shall be applied to all special discount cases that come before us during the transition period, including those currently pending. PG&E shall apply the cost allocation adopted in D.95-10-033 to its rate discount contracts. We shall adopt allocation formulas for SCE and SDG&E in the appropriate rate design proceeding.

38. The Commission Advisory and Compliance Division (CACD) shall prepare an Environmental Impact Report (EIR) for our consideration. CACD shall issue a Notice of Preparation of an EIR within 100 days of the effective date of this decision. CACD shall retain the services of a qualified professional environmental consultant, who shall conduct an independent analysis which shall result in the publication of both a Draft and Final EIR. The

Final EIR shall be prepared in full compliance with the California Environmental Quality Act (CEQA) and Rule 17.1 of this Commission's Rules of Practice and Procedure.

39. PG&E, SCE, and SDG&E shall reimburse the Commission for its costs in preparing the EIR, including, but not limited to, the costs of retaining an independent consultant who shall be selected solely by CACD. PG&E, SCE, and SDG&E shall share and recover these costs in the manner employed to allocate and recover the Public Utilities Commission Reimbursement Account fees.

40. We will establish an independent education trust modeled after the Telecommunications Education Trust, the purpose of which is to ensure independent, multicultural education, advocacy, and research for small business and residential customers.

This order is effective today.

Dated December 20, 1995, at San Francisco, California.

DANIEL Wm. FESSLER
President
P. GREGORY CONLON
HENRY M. DUQUE
Commissioners

We will file a written dissent.

/s/ JESSIE J. KNIGHT, JR.
Commissioner

/s/ JOSIAH L. NEEPER
Commissioner