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Decision 97-05-040 May 6, 1997

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) ORIGINAL
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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SECOND INTERIM OPINION

Summary

Momentous changes are occurring in the regulation of the electric utility industry. As we move away from a regulated environment, we are creating the framework for a competitive electric market that we expect will bring significant benefits to consumers and to the State of California. One important element of this restructured market is that electric customers will be able to purchase power directly from competing nonutility suppliers, and indirectly from other kinds of retail electric service providers such as aggregators, brokers, and marketers. Those retail customers who do not want to purchase directly from suppliers or other electric service providers will continue to receive service from their existing electric utility.

Today's decision addresses some of the policy and time-critical issues regarding direct access that we previously referred to as Track 1 or threshold issues. (Decision (D.) 96-12-088, p. 19.) These threshold issues need to be addressed so that the parties will know what they can expect in the coming months before direct access transactions become a reality. In addition, timely determinations on these policy issues need to be reached because their outcome affects the schedule for the numerous implementation details that need to be worked out in the months to come.

The policies and rules which we adopt today will facilitate the creation of a competitive marketplace in California for electric energy. This is being accomplished by allowing the implementation of direct access for all customer classes beginning on January 1, 1998. In its most fundamental sense, direct access is about customer choice. We find no grounds for limiting that choice. However, that does not mean that everyone who wants direct access on a certain date can be switched over by then. In this decision, we establish the basis for an implementation plan that will provide for an orderly "roll out" of direct access. Direct access requests will be honored on a first-come, first-served basis, with an exception for customers whose loads are supplied by a renewable resource provider. We expect the utilities to process those requests as expeditiously as possible. Depending on the overall volume of requests, temporary backlogs may develop. However, the implementation process we adopt today will strictly limit the size and duration of such backlogs.

Industrial and large commercial and agricultural customers who want to take advantage of the benefits of direct access must have in place meters capable of providing hourly data. For the accounts of residential customers, commercial and agricultural customers, and other customers with a maximum demand of less than 20 kilowatts (kW), we will permit the use of statistical load profiles so that they can take advantage of the direct access option. Aggregation of customers interested in participating in direct access transactions shall be permitted. Making direct access as available, accessible, and as convenient as possible should help to mitigate market power in the Power Exchange (PX).

Those entities offering electrical service to residential and small commercial customers will be required to register with the Commission using a simple registration process. Such a procedure will ensure that these classes of customers will be protected from unfair or abusive marketing practices. Allowing easy entry into the marketplace for both consumers and suppliers of electricity is a key tenet of our direct access program, and will encourage and stimulate competition in the direct access market and in the PX.

A series of various workshops and reports will be needed over the next several months to address the implementation details associated with direct access. Many of these workshop issues will need to be further addressed by the Commission before direct access begins on January 1, 1998.

We anticipate issuing another decision shortly which will specify the particulars of our other market rules, including billing and other metering issues, consumer protection safeguards, and monitoring of the new regulatory environment.

Background of Electric Restructuring

The process of electric restructuring began back in September of 1992, when the Commission initiated a comprehensive review of current and future trends in the regulation of electricity.[1] The Commission opened a rulemaking and investigation in April 1994, to examine ways in which California's electric services industry could be restructured and regulation could be reformed. The Commission sought written comments to the rulemaking and investigation. The Commission held five full panel public hearings in early 1995, at four different locations in the state on the subject of industry restructuring and regulatory reform. In addition, 16 public participation hearings were held throughout the state in order to solicit input from the citizens of this state.

On May 24, 1995, the Commission issued D.95-05-045. That decision accompanied statements of majority and minority views of preferred market structures. After the issuance of D.95-05-045, the Commission held four additional full panel hearings. These full panel hearings covered such topics as wholesale pool dispatch, operations and market power issues, the competition transition charge, public purpose programs, and the substance and consequences of the memorandum of understanding that certain parties had jointly agreed to.

The above process culminated in the issuance of D.95-12-063, as modified by D.96-01-009, commonly referred to as the Preferred Policy Decision. The Preferred Policy Decision adopts a framework for competition in which customers have the right to choose their supplier of electricity. One of the effects of this new framework is to transform California's electricity systems from a bundled electric service system that is provided by the investor-owned electrical corporations, to a set of segmented functions, including, generation, transmission, and distribution.[2]

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[1] For a detailed procedural history of this proceeding, see pages 19 and 24, and Appendix B of D.95-12-063, as modified by D.96-01-009.

[2] Assembly Bill 1890, as enacted (Stats. 1996, ch. 854.), added Section 330 to the Public Utilities Code. Subsection (k) of that code section reiterates the importance of the separation of these three functions. Subsection (k) provides: "In order to achieve meaningful wholesale and retail competition in the electric generation market, it is essential to do all of the following: (1) Separate monopoly utility transmission functions from competitive generation functions, through development of independent, third-party control of transmission access and pricing.

Footnote continued on next page

Integral to this new market structure is the establishment of the independent system operator (ISO) and the PX. The ISO is responsible for operating the transmission system. The purpose of the PX is to develop a spot market for electricity that is open to all suppliers, including out-of-state suppliers and municipal utilities. The design and operation of both the ISO and the PX have been given preliminary approval by the Federal Energy Regulatory Commission (FERC). Final approval is expected sometime towards the Fall of 1997.

Under the Preferred Policy Decision, customers will have several options in deciding how they want to participate in the market. Direct access permits direct and indirect sales of electric services to retail, end-use customers. Customers can choose to purchase power according to default rates from their current utility, through direct negotiated terms and conditions with competing non-utility retail electric service providers, or through brokers, marketers, aggregators, and other retailers . The utility distribution company (UDC) will continue to procure power for those customers who do not want to arrange their own retail contracts with non-utility suppliers. The UDCs will also provide nondiscriminatory distribution services to all customers within their service territories. For a four year transition period, generation that is owned or controlled by the UDCs will have to be bid into the PX, and the UDCs are required to obtain electricity on behalf of their utility service customers with purchases made from the PX. (D.96-12-088, pp. 7, 42.) Under the Preferred Policy Decision, it was envisioned that all customers will have the opportunity to exercise any of the above choices no later than five years from the start of this restructured market environment. Assembly Bill (AB) 1890 shortened this period from five to four years. (D.96-12-088, p. 7; see P.U. Code Section 365(b)(1).)

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(2) Permit all customers to choose from among competing suppliers of electric power. (3) Provide customers and suppliers with open, nondiscriminatory, and comparable access to transmission and distribution services."

The Preferred Policy Decision ordered Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (Edison) to confer with other parties before submitting their proposals on direct access. The proposals were to include, among other things, the eligibility parameters for the initial phase of direct access and for later stages.

The implementation details of how to carry out the Preferred Policy Decision and to create this competitive electric industry were addressed in D.96-03-022, commonly referred to as the Roadmap Decision. In the Roadmap Decision, the Commission called for the formation and recognition of a number of working groups, made up of interested stakeholders, to aid in the resolution of many of the implementation concerns. These various working groups were arranged by the grouping of major issues. Each of the groups of issues was assigned to individual Commissioners. One of the groupings was comprised of consumer choice issues, including direct access, consumer safeguards, and public purpose programs. The Direct Access Working Group (DAWG), which was recognized in the Coordinating Commissioner's letter of June 21, 1996, was formed to address direct access and consumer safeguard issues.

In the Roadmap Decision, the Commission directed that the direct access proposals should address, at a minimum, the following:

> "a. A specific plan for the initial twelve-month initial phase of direct access that determines participation in the initial phase of direct access beginning no later than January 1, 1998. This plan should include but not be limited to delineation of all requirements for participation, including any necessary metering requirements, dissemination of customer information and monitoring and evaluation mechanisms.
>
> "b. A specific eligibility plan for direct access which addresses whether a phase-in schedule is necessary or whether eligibility can be held open to all consumers after the twelve month initial phase.
>
> "1. The plan should identify any technological barriers or any other concerns to offering direct access to all

electric consumers after the initial phase and identify options to reduce or eliminate the barriers.

"2. If a phase-in of eligibility beyond the initial phase is proposed, the Working Group plan should consider the Commission's phase-in schedule for direct access and propose alternatives, if any, to that schedule.

"c. Proposed rules for customer aggregation.

"d. Proposed rules for new market participants such as marketers, brokers, direct access suppliers and other energy service providers.

"e. Analysis of various metering and communication systems including, appropriate metering capability, scheduling of meter installation, cost implications, etc." (D.96-03-022, pp. 23-24.)

The Roadmap Decision at page 26 also stated that a workshop report should be filed which discusses consumer protection guidelines for electric restructuring, including a recommended action plan for public outreach and education. The workshop report was to address the following issues as well: monitoring and compliance; service and safety; obligation to serve; and the Commission's role. The Roadmap Decision established October 30, 1996, as the date for the filing of this workshop report on consumer protection. These proposals were to be developed through scoping workshops. The purpose of the scoping workshops was to further define the issues to be discussed by the working groups, and to determine if any factual matters needed to be resolved through evidentiary hearings.

Commissioners Knight and Neeper were jointly assigned oversight responsibility for direct access and consumer education and protection. Commissioners Knight and Neeper issued a Joint Assigned Commissioners' Ruling (JACR) on April 4, 1996. That ruling fixed April 22, 1996, as the date for the scoping workshop to be held on direct access, consumer education and protection, and public purpose programs.

A number of stakeholders met several days before the April 22, 1996 scoping workshop to begin organizing the DAWG. This meeting resulted in the adoption of a mission statement and the structuring of the DAWG into four technical teams and a coordinating committee. The four teams were established to address the following issues: implementation; market rules; metering and communications systems; and consumer education and protection. Following the April 22, 1996 scoping workshop, the DAWG and the technical teams held a series of meetings to address and discuss the direct access and consumer choice issues in detail and to develop proposals for the Commission's consideration.

On August 30, 1996, the DAWG report entitled "Design and Implementation of Direct Access Programs" (August 30, 1996 DAWG Report) was filed with the Commission's Docket Office. The August 30, 1996 DAWG Report represents a compendium of ideas from the DAWG members on the various consumer choice issues, and how these issues can be addressed so as to achieve the goals previously expressed by the Commission in its Preferred Policy Decision. Interested persons were provided with the opportunity to file opening and reply comments to the August 30, 1996 DAWG report. These comments were filed on September 30 and October 15, 1996, respectively. See Appendix A for the list of parties who filed comments to the August 30, 1996 DAWG Report.

On September 27, 1996, Commissioners Knight and Neeper issued a JACR notifying parties of a forum to be held on October 10, 1996, for Commissioners to hear oral comments on the August 30, 1996 DAWG report. That ruling also listed a series of 11 questions that Commissioners Knight and Neeper wanted addressed at the forum, or in the October 15 reply comments to the August 30, 1996 DAWG report.

Pursuant to the Roadmap Decision, and the May 17, 1996 JACR, the "Direct Access Working Group Report On Consumer Protection And Education Report In A Restructured Electric Industry In Response To May 17, 1996 Joint Assigned Commissioner's Ruling" was submitted to the Commission on October 30, 1996 (October 30, 1996 DAWG Report). Opening and reply comments to the October 30, 1996, report were filed on November 26 and December 11, 1996, respectively.

On November 26, 1996, the FERC issued an order which conditionally approved the ISO and PX. (<u>Pacific Gas and Electric Company, San Diego Gas & Electric Company</u>

and Southern California Edison Company, "Order Conditionally Authorizing Establishment of an Independent System Operator and Power Exchange, Conditionally Authorizing Transfer of Facilities to an Independent System Operator, and Providing Guidance," 77 FERC ¶ 61,204 (November 26, 1996).)

On December 9, 1996, Commissioners Knight and Neeper issued a JACR directing PG&E, SDG&E, and Edison to meet with interested participants concerning the coordination of the communications and data systems needed for the ISO, PX, UDC, SCs, and direct access providers. The meeting was to also discuss whether these systems would result in any technical limitation on allowing direct access for all customers. The ruling also required that a report be filed on or before January 17, 1997, and that the report shall:

> "1. explicitly identify the communications and data systems and the minimum performance criteria for each element needed for the ISO, PX, UDC, SCs and direct access providers;
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> "2. clearly explain the necessary integration points and capability requirements of the various communications and data systems and describe the minimum performance criteria for each element;
>
> "3. present any known timelines related to the design, development, installation and testing of the systems leading up to implementation of direct access by January 1, 1998;
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> "4. identify and explain in detail, areas of technical limitation that these systems place, if any, on allowing all customers to be eligible for direct access by January 1, 1998; and
>
> "5. delineate the appropriate solutions to any technical limitations or, at a minimum, if there are no known solutions, a process and projected schedule by which to accomplish their resolution."

The meeting was held on January 9, 1997. A workshop report addressing the subjects covered at the meeting, as well as the above topics, was filed with the

Commission on January 17, 1997. Comments to this report were filed by interested parties on January 24 and January 28, 1997.

Beginning in 1994, the California Legislature became involved in the restructuring of California's electric industry. The Legislature approved AB 1890, which was then signed into law by the Governor on September 23, 1996. (Stats. 1996, ch. 854.) In enacting AB 1890, the Legislature declared the following:

> "It is the intent of the Legislature to ensure that California's transition to a more competitive electricity market structure allows its citizens and businesses to achieve the economic benefits of industry restructuring at the earliest possible date, creates a new market structure that provides competitive, low cost and reliable electric service, provides assurances that electricity customers in the new market will have sufficient information and protection, and preserves California's commitment to developing diverse, environmentally sensitive electricity resources." (Stats. 1996, ch. 854, Section 1(a).)

AB 1890 also directed the Commission to authorize direct transactions between electricity suppliers and end use customers. These direct transactions are to commence simultaneously with the start of the ISO and the PX. This commencement is to occur as soon as practicable but no later than January 1, 1998. (Stats. 1996, ch. 854, Section 10, p. 29; P.U. Code Section 365(b).)[3]

AB 1890 also declared that: "It is the intent of the Legislature to protect the consumer by requiring registration of certain sellers, marketers, and aggregators of electricity service, requiring information to be provided to consumers, and providing for the compilation and investigation of complaints." (Stats. 1996, ch. 854, Section 1(d).)

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[3] Unless otherwise noted, all "section" references are to the Public Utilities Code, as amended by AB 1890.

Procedural Background

There are several procedural matters to address. Payless ShoeSource, Inc. (Payless) filed a motion to intervene in this proceeding on September 25, 1996. Payless operates approximately 660 stores in California and is interested in reducing its costs for electricity. No one filed any response to the motion. In the interest of soliciting as many viewpoints as we can on electric restructuring, we will grant Payless' motion to intervene.

CellNet Data Systems, Inc. (CellNet) served copies of its opening comments to the August 30, 1996 DAWG Report on the DAWG members. However, CellNet did not file its opening comments with the Commission's Docket Office.[4] We will direct the Docket Office to accept CellNet's opening comments to the August 30, 1996 DAWG Report for late filing should CellNet desire to formally file its opening comments with the Docket Office as part of this proceeding.

On October 16, 1996, the California Large Energy Consumers Association (CLECA) and the California Manufacturers Association (CMA) filed a motion for leave to file their reply comments to the August 30, 1996 DAWG Report one day late. The motion recites that CLECA and CMA were unable to coordinate the final revisions to their joint reply comments before the due date. No one has objected to the motion. We will grant the motion of CLECA and CMA to late file its joint reply comments. The Docket Office shall be directed to file as of October 16, 1996, the reply comments of CLECA and CMA that were attached to the motion.

On November 19, 1996, Cinergy Services, Inc. (Cinergy) filed a motion to supplement its October 15, 1996 reply comments to the August 30, 1996 DAWG Report. Cinergy had recommended in its October 15, 1996 comments that direct access should

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[4] CellNet's reply comments to the August 30, 1996 DAWG Report was filed with the Docket Office.

be implemented for all California customers on January 1, 1998, without the need for any partial phase-in. Cinergy's motion seeks to supplement the October 15, 1996, comments with an additional reason for avoiding a partial phase-in. The motion states that this supplemental information was based on discussions with others after the time for filing the reply comments had elapsed, and was not available at the time the October 15, 1996 reply comments were filed. The supplemental information that Cinergy seeks to include is part of the body of the motion.

No one has filed a response to Cinergy's motion. In order to obtain as much input as we can on electric restructuring, we will grant Cinergy's motion to supplement its October 15, 1996, reply comments to the August 30, 1996 DAWG Report. The supplemental comments attached to Cinergy's motion shall be treated as though they were attached to Cinergy's October 15, 1996, reply comments.

The proposed decision in this matter was mailed to the parties on March 12, 1997. In a joint assigned Commissioners' ruling of the same date, all interested parties were given the opportunity to provide written comments on the Administrative Law Judge's (ALJ) proposed decision. On April 17, 1997, Commissioner Conlon mailed out an alternate to the ALJ's proposed decision for comment.

The comments to the March 12, 1997 proposed decision and to Commissioner Conlon's alternate have been reviewed and considered. As a result of the comments, both substantive and non-substantive revisions to the proposed decision have been made.

Which Utilities Are Obligated To Provide Direct Access?

In the Preferred Policy Decision, the Commission envisioned that direct access would only apply to the service territories of PG&E, SDG&E, and Edison. Those three investor-owned electrical corporations were requested and authorized in the Preferred Policy Decision to develop proposals to establish the ISO and the PX at the FERC. (Preferred Policy Decision, pp. 218-221; D.97-02-021, p. 17.) Nowhere in the Preferred Policy Decision did the Commission address how customers in the service territories of other Commission regulated electrical corporations would be treated. The other

Commission-regulated electrical corporations are Kirkwood Gas and Electric (Kirkwood), PacifiCorp, Sierra Pacific Power Company (Sierra Pacific), and Southern California Water Company (SCWC).

AB 1890 does not appear to limit the legislation's applicability with respect to direct access to the state's three largest electrical corporations. Instead, AB 1890's enactment of Section 330 permits all customers to choose from among competing suppliers of electric power. Accordingly, our rules regarding direct access shall apply to all investor-owned electrical corporations.

Direct Access Helps Mitigate Market Power

Electric restructuring is going to bring changes to the ways in which the electric utilities are currently structured. Under the Preferred Policy Decision and AB 1890, control of the transmission facilities will be transferred to the ISO. There will be many different electric generation providers who will be selling their power through the PX. Distribution of electricity will be through the UDCs. A new category of sellers of electricity will be created. The creation of all these different entities will result in the FERC retaining jurisdiction over some entities and situations, while this Commission will retain jurisdiction in other areas.

As we stated in the Preferred Policy Decision, this new market structure will require close cooperation and coordination with the FERC, and will require exercise of jurisdiction by both the FERC and this Commission under a policy of cooperative federalism. (Preferred Policy Decision, p. 26.) This policy of cooperative federalism recognizes that both state and federal regulatory agencies must cooperate if a competitive and productive electric services industry is to be realized. This policy is also reflected in AB 1890. (See Sections 330, 346, 360, 365.)

Our electric industry restructuring initiative remains founded on the creation of a competitive marketplace for electric energy and its derivative products and services. This Commission initially identified a number of issues associated with the direct access and unbundling aspects of this initiative as having market power implications for electric restructuring in California. (See Preferred Policy Decision, pp. 90-109.) These concerns will have to be addressed both in our own proceedings, and in our comments before the FERC in order for the investor-owned electrical corporations to obtain federal approval for market-based pricing in the PX.

In our October 17, 1996, comments to the FERC in Phase I of the FERC proceedings to authorize the sale of electric energy through the PX using market-based rates (ER96-1663-000), we indicated that this Commission will address market power issues, primarily through mitigation and monitoring mechanisms, in our own state proceedings in addition to the efforts that we, and other parties to the FERC proceedings, may undertake in that forum. We remind the parties to our electric restructuring proceedings that whatever market power mitigation and monitoring measures we adopt in our proceedings, will be echoed by this Commission in our subsequent comments and positions taken before the FERC. We also recognize that certain aspects of this Commission's decisions in the electric restructuring proceedings may be impacted by the outcome of the FERC's decisions on those related issues.

To address market power concerns in both the PX and the emerging direct access markets, the direct access option cannot be merely a theoretical option for consumers, but must be a fully developed and viable option. We indicated in our October 17, 1996 comments to the FERC that we would specifically examine how direct access might be used to limit the investor-owned electrical corporations' ability to influence prices in the PX.

We see the availability of direct access as limiting the exercise of market power in the PX. If prices in the PX were to rise as a result of the exercise of market power by any entity, customers could decide to buy power through bilateral contracts in the direct access market instead of in the PX. However, for direct access to be a real alternative, it must be widely available, accessible, and convenient. If direct access is not available because it is subject to a slow phase-in; or if it is cumbersome because it requires customers to deal with many separate entities; or if it is not cost competitive because of some duplicative costs, it may not be an alternative to the PX market, thereby diminishing its mitigating effect on market power in the electric energy markets in general, and in the PX specifically.

To ensure that direct access is available, accessible, and convenient, our preference is to open up direct access as widely and as quickly as possible, limited only by binding technical constraints. As discussed below, based on parties' comments in this proceeding, there are no binding operational or technical constraints which stand in the way of opening up direct access to all customers on January 1, 1998.

We are also concerned about the exercise of market power in the direct access market itself. It is possible that the investor-owned electrical corporations might have a distinct advantage in the direct access market in terms of established customer relationships, customer contact, and customer information. This would yield advantages in marketing activities and customer retention programs. Therefore, we must guard against any abuse of market power in the emerging direct access market, as well as in the PX.

Direct access could also be made more convenient and cost competitive if a competitive market is allowed to develop for metering and billing services. The unbundling aspect of this proceeding is currently addressing those issues.

A direct access program designed along these lines would limit the ability of the investor-owned electrical corporations to influence prices in the PX. In addition, such a direct access option offers a viable, effective, and dependable alternative to the PX for both consumers and suppliers of electric energy products and services. As discussed in the sections which follow and in our decision on the customer education program, we therefore adopt the following:

- The opportunity for all customer classes to choose direct access as an option immediately;

- Provision of customer identification and marketing information on an equal basis to potential electric service providers;

- Removal of barriers to potential new entrants who wish to establish customer relationships for a variety of energy-related products and services; and

- Establishment of adequate consumer education, information, and protection programs.

Direct Access Means Retail Competition

The discussion of direct access in electric restructuring has led to the use of multiple terms for those entities that serve end-use, retail consumers. The Preferred Policy Decision and AB 1890 speak of aggregators, brokers, and marketers in general without drawing distinctions between them. Section 331 provides the following definitions:

> "(a) 'Aggregator' means any marketer, broker, public agency, city, county, or special district, that combines the loads of multiple <u>end-use customers</u> in facilitating the sale and purchase of electric energy, transmission, and other services on behalf of these customers.
>
> "(b) 'Broker' means an entity that arranges the sale and purchase of electric energy, transmission, and other services between <u>buyers</u> and sellers but does not take title to any of the power sold.
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> "(c) 'Direct transaction' means a contract between any one or more electric generators, marketers, or brokers of electric power and one or more <u>retail customers</u> providing for the purchase and sale of electric power or any ancillary services.
>
> . . .
>
> "(e) 'Marketer' means any entity that buys electric energy, transmission and other services from traditional utilities and other suppliers, and then resells those services at wholesale or to an <u>end-use customer</u>." (Emphasis added.)

There is a great deal of overlap between aggregators, brokers, and marketers. Any marketer or broker that serves more than one customer could also be considered an aggregator. Clearly, direct transactions, or direct access as we refer to it, involves the provision of electric service to retail customers. Retail customers are the end-use buyers of electric service. In fact, the concept of direct access was originally referred to as "retail wheeling" by most of the industry prior to the Commission's restructuring process.

It is clear from reading AB 1890 that the Legislature intended that those electric service providers supplying service to end-use consumers, i.e. retailers, regardless of being classified as aggregators, brokers, or marketers, would have certain rights and responsibilities under the act. Basically a "retailer" is any electric service provider that enters into a "direct transaction" with an end-use consumer. For example, a power generator that sells power to a marketer, who then engages in a direct transaction with an end-use consumer, is not a retailer. However, should that same generator sell power directly to an end-use consumer, that entity would be a retailer.

This concept of a retail provider of energy is important because it is this entity, regardless of whether it is an aggregator, broker, or marketer of power, that will have contact with consumers and, like the UDCs, have the responsibility of meeting the needs of California's electricity consumers.

In this decision, the term "retailer" refers to any entity, whether it is a non-utility generator, aggregator, broker, or marketer, which offers electrical service to end-use customers.[5] Anyone entering into a "direct transaction" with a retail customer is a retailer. We note that among their other roles, the investor-owned utilities are also retailers of electricity. In fact, it is this very function, retailing, that is being opened up to competition by the restructuring of the electric industry. However, to avoid further confusion, UDCs are not included in the definition of retailers, though they may have affiliates that are.[6]

Generally we will seek to create a level playing field among retailers and attempt to eliminate or minimize differences in regulations among them to allow for greater and fairer competition. However, AB 1890 does not refer explicitly to retailers and hence we

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[5] A schedule coordinator who interacts directly with end use customers as an aggregator, broker, or marketer would also be considered a retailer.

[6] Retailers and the UDCs will compete against each other to serve end-use consumers. In addition some retailers may also have a wholesale business. For example a marketer could sell power to other retailers, to utilities in the wholesale market and also to end-use consumers in the retail market.

will be careful to specify that with respect to retailers the obligations and rights imposed by AB 1890 are linked to their activities as either an aggregator, broker , marketer, or other entity specified under AB 1890.

Direct Access Transactions

Background

In the Preferred Policy Decision, the Commission specified a plan to offer customers a choice in obtaining electric services. The plan was to begin a phase-in of direct access to begin no later than January 1, 1998, with a twelve-month initial phase. Implementation of the initial phase was a means of cautiously approaching a new competitive framework so that the market could: (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. After the initial phase, the Commission specified that it would make the direct access option available to all customer classes within five years. (Preferred Policy Decision, p. 65.)

In the absence of an agreement for an earlier implementation schedule, the Preferred Policy Decision adopted the following schedule for the phasing in of direct access for Edison, PG&E, and SDG&E. The schedule specifies, by year, the total number of megawatts that must be available for participation in direct access.

	Edison/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.

The Preferred Policy Decision also adopted an eligibility parameter of 8 megawatts (MW) as the threshold limit for individual customers and aggregated customer groups.

The Preferred Policy Decision, however, provided a great deal of flexibility regarding the phase-in approach. The Commission solicited comments on whether a minimum phase-in schedule was even necessary, and whether eligibility could be opened to all electricity consumers before the five year period or even after the twelve month initial phase. The Commission stated: "[w]e do not favor restrictions beyond those necessary due to technical obstacles, though we recognize that some parties may have additional concerns." (Preferred Policy Decision, pp. 69, 220-221; D.97-02-021, p. 46.)

In D.97-02-021, the decision which addressed the applications for rehearing of the Preferred Policy Decision, the Commission stated that the issues raised on rehearing about eligibility for direct access were made moot by AB 1890 and subsequent events. The Commission also stated that the default schedule set forth in the Preferred Policy Decision was no longer appropriate, or even necessary. (D.97-02-021, pp. 48-49; See D.96-12-088, pp. 16-17.)

Impact of AB 1890

AB 1890 shortens the time by which all customers shall have the option of direct access available to them. Under AB 1890, any such phase-in must be completed by January 1, 2002. In addition, it provides that any phase-in of customer eligibility for direct transactions shall be equitable to all customer classes and <u>accomplished as soon as practicable, consistent with operational and other technological considerations</u>. (Section 365(b)(1), emphasis added.) Should a phase-in of direct access be required, AB 1890 mandates that any customer whose load is at least one-half supplied by a certified renewable resource provider is automatically eligible for direct access regardless of the phase-in. (Section 365(b)(2).)

Do Direct Access Constraints Exist?

We first address the issue of whether a phase-in of direct access is necessary at all. As we noted in the Preferred Policy Decision at page 69, and as the JACR of December 9, 1996 pointed out, any phase-in of direct access should be based on a demonstration of technical constraints. Commissioners Knight and Neeper stated emphatically in the December 9, 1996 ruling that "if no specific technical constraints are demonstrated, we expect to propose to the Commission that all customers be eligible for direct access by January 1, 1998."

Section 365(b)(1) provides that any phase-in should be accomplished as soon as practicable, consistent with "operational and other technological constraints." Technical constraints are technology-based limitations which impede or harm the reliable operation of the electrical system. AB 1890 does not preclude the opportunity for all customers to choose direct access implementation on January 1, 1998, so long as it is feasible. Given our prior pronouncements, and AB 1890's guidance, we believe that in the absence of any showing of operational and other technical constraints, that no phase-in is required. If, however, there are operational and other technological constraints, then the phase-in should be completed as quickly as possible.

In comments to the August 30, 1996 DAWG report, several parties argued that some phase-in period is necessary and critical to the success of direct access and offered various phase-in proposals for the Commission's consideration. These suggestions are designed to address so-called "commercial constraints," having to do with the UDCs' abilities to process direct access requests and make the necessary billing and metering changes to effectuate those switches. PG&E and Edison propose a 3-year phase-in, limiting transactions in 1998 to a total of 1800 MW, after which a monthly rollout process would enable 50% of customers to be eligible by January 1, 2000, and all customers to be eligible by January 1, 2001. A few parties advocated a one-year phase-in of no less than the 1800 MW as specified in the Preferred Policy Decision, with full implementation by January 1, 1999. However, some of the parties who had originally supported a one-year phase-in indicated in their comments to Commissioner Conlon's April 17, 1997 alternate that they no longer supported a limited phase-in because of the acknowledgment by the utilities that no technological constraints exist.

The remaining parties believe that no phase-in period is required, and that all customers should be eligible for direct access beginning January 1, 1998. In particular, they contend that specific technical limitations related to data processing capabilities and integration of communications and data systems, which would prevent eligibility of direct access to all customers by January 1, 1998, have not been fully explained or demonstrated.

An extensive record in this rulemaking and investigation has focused on whether there are any operational and other technological constraints to direct access. The August 30, 1996 DAWG Report addressed this issue, as did the numerous comments to this report. In addition, in the December 9, 1996 JACR, Commissioners Knight and Neeper directed that a meeting be held to discuss the various communications and data systems that need to be coordinated, and that the report resulting from that meeting shall, among other things: "identify and explain in detail, areas of technical limitation that these systems place, if any, on allowing all customers to be eligible for direct access by January 1, 1998;" and "delineate the appropriate solutions to any technical limitations or, at a minimum, if there are no known solutions, a process and projected schedule by which to accomplish their resolution."

The "Report On January 9, 1997 Direct Access Working Group Workshop On Communications And Data Systems" was filed on January 17, 1997 (January 17, 1997 Report). All of the comments to this report, except for those of the California Energy Commission (CEC), contend that the January 17, 1997 Report demonstrates that there are no technical barriers to full direct access.

The January 17, 1997 Report concluded that:

> "All three Companies [PG&E, SDG&E, and Edison] agree that there are no technical limitations to direct access based on the ISO systems as presently designed or on the UDC systems as the Companies anticipate they will be adapted. For the practical and commercial reasons discussed at the workshop and detailed here, Edison and PG&E advise a phase-in of direct access and SDG&E disagrees." (January 17, 1997 Report, p. 67.)

The January 17, 1997 Report at page 49 also stated that:

> "SDG&E does not believe that there are any technical or operational limitations that justify limiting the availability of direct access. Based on our analysis of systems requirements downstream of the ISO, we do not see any difference in systems required depending on whether or not the competitive market is permitted to offer metering and billing services (i.e., unbundling of the 'revenue cycle').

> Therefore, the scope of unbundling does not create any technical or operational limitations to full availability of direct access. The 'standards' necessary for implementing direct access—that is, metering standards, communications protocols and similar requirements—either already exist, or can be developed easily by January 1, 1998. Accordingly, standards development is not an impediment to implementing direct access."

In reporting on Edison's point of view, the January 17, 1997 Report at page 27 stated:

> "In Edison's opinion there are no 'technical' constraints on full direct access January 1, 1998, presented by the operations of the ISO, the PX, the Scheduling Coordinators or the UDCs. However, there are other considerations, which some parties have characterized as 'practical' or 'commercial,' which will have as great an impact on the success of direct access and which ought to be considered by the Commission in its decision on phase-in."(Id., at p. 27.)

As stated above, technical constraints are technology-based limitations which impede or harm the reliable operation of the electrical system. For example, a technical constraint would be a problem with the design or development of the computer systems needed for the ISO to perform its numerous operating, dispatch, and scheduling functions so as to allow the safe and reliable operation of California's interconnected electric system. PG&E, SDG&E, and Edison have agreed that there are no technical constraints to providing all customers with the opportunity to choose direct access by January 1, 1998. The ISO Trustee, S. David Freeman, whose letter to Commissioners Knight and Neeper was part of the January 17, 1997 Report, stated that the ISO's systems are designed to accommodate up to 2000 connected entities, approximately 1000 of whom would be schedule coordinators (SCs). This limitation on the number of SCs "is not, in and of itself, a limit on the number of direct access customers that can be accommodated. Instead, the number of direct access customers that can be accommodated is dependent on the number of customers that the SC [schedule coordinator] can serve." (January 17, 1997 Report, p. 5.)

PG&E, SDG&E, and Edison all concur that no matter what the Commission's decision on phase-in is, there will be no impact on the physical reliability of electricity service. (January 17, 1997 Report, Executive Summary, p. 2.) Although we are confident that no reliability problems will arise, we will vest the ISO with the ability to call for a moratorium in the processing of direct access requests, should an "emergency" exist. This procedure is described in further detail below.

The next question is whether there are any other operational considerations that warrant a phase-in period. Operational constraints are those things which affect the physical reliability and operation of a system. Edison believes that "the scale, complexity and novelty of the operations and interactions among the ISO, PX, scheduling coordinators, and UDCs will virtually guarantee that problems will occur during the early days of 1998" (Id., at pp. 27-28). They assert that it is inevitable that problems will arise as numerous untested hardware and software systems begin to operate and handle transactions, in conjunction with people performing their roles for the first time. Edison contends prudent business judgment and risk management dictate that the number of transactions should be limited to work out the flaws in the various systems.

PG&E believes that if the number of initial customers is relatively small, it will be easier to continue direct access with backup processes, such as manual procedures, until the unexpected problems are fixed or adjustments are made to any of the integrated computer systems. PG&E also believes that it will be easier to make adjustments to the program if there is a smaller number of participants. PG&E also contends that operational factors, such as the lead times needed for changes to its customers' accounts and contract processing systems, should be considered in deciding whether there should be a phase-in or not. PG&E believes that the elimination of a phase-in will raise uncertainty about the needed size and capabilities of the systems, which could lead to unnecessary expenditures or to a lack of adequate resources.

Edison and PG&E raise some valid considerations about possible situations which could impact the efficient operation of the new market structure. They assert that new complex computer systems must support both the operational requirements of the electric system and the underlying commercial transactions that are occurring in the competitive marketplace between the UDCs, the electric service providers and consumers. These include the numerous transactions that will be necessary to switch customers over from their utility supplier to alternative energy providers. Although these considerations may not impact the physical reliability and integrity of the electrical system, they can affect the integrity of the commercial aspects of the system and need to be taken seriously. In our discussion below of how to implement direct access, we address these concerns.

We agree with PG&E and Edison that limiting the number of transactions may make it easier to test the various systems, work out any flaws, and make adjustments or corrections to any procedures or systems. On the other hand, we do not anticipate that on January 1, 1998, there will be an instantaneous shift to direct access by all consumers. To the contrary, we expect to see in this market, as we have seen in the telecommunications market, a gradual migration to, and an interest in, direct access. In the formative years of direct access, other market forces will operate to limit the number of customers who decide to avail themselves of the direct access option. For example, the processes imposed by this decision and by AB 1890, while of importance for the protection of consumers, may dampen the rate of direct access implementation. At the same time, however, we recognize that these are not sufficient grounds to assume that problems might not emerge as the switch-over of customers to direct access is made, especially in the initial months. In our direct access implementation discussion below, we lay out a plan that balances the need to accommodate as many direct access requests as possible with the objective of preserving the commercial integrity of the systems needed to make those changes.

Threshold Eligibility

In the Preferred Policy Decision, we stated that an eligibility parameter of 8 MW, as the threshold limit for individual customers and aggregated customer groups in the initial phase, seemed reasonable. However, we also directed the parties to confer and to recommend eligibility parameters. Since the adoption of the Preferred Policy Decision, the ISO's role has been further developed and refined. During this process, the role and function of the SCs have become more clear as well.

The ISO may eventually seek to establish a minimum load for the schedules submitted by the SCs. The ISO has technical limitations that may limit the number of SCs initially, which will in turn impact the number of schedules that the ISO can accommodate at the outset. (See January 17, 1997 Report, p. 5.)

However, the role of the SCs, as noted by the CEC, will reduce the transactions processing burden on the ISO. (CEC Comments to August 30, 1996 DAWG Report, p. 45.) The SC will reduce the burden on the ISO because the SCs will perform a second level aggregation of various direct access transactions prior to submitting the schedules to the ISO. The first level of aggregation will occur when retail marketers and aggregators combine and consolidate the loads of their end use customers. As noted by the ISO Trustee:

> "The January 1, 1998 limitation of approximately 1,000 SC is not, in and of itself, a limit on the number of direct access customers that can be accommodated. Instead, the number of direct access customers that can be accommodated is dependent on the number of customers that the SC can serve." (January 17, 1997 Report, p. 5.)

Since the proposed ISO requirement does not provide for a minimum load for the schedules submitted by the SCs, a minimum MW load requirement would limit the number of providers that could participate in the market. Such a requirement would also unnecessarily discriminate against the smaller electric service providers seeking to serve smaller customers, as well as small commercial and residential customers. The 8 MW limitation is also inconsistent with Section 366(a) that customers be "entitled to aggregate their electric loads on a voluntary basis," because it arbitrarily limits how and with whom customers can aggregate.

We believe that the requirement of the ISO that all direct access transactions must be scheduled by a SC, and that the SC must provide a balanced schedule, are effective substitutes for minimum aggregation load levels.

Implementation Of Direct Access

For the reasons described above, we find that there are no operational or other technological considerations which would warrant us from limiting a consumer's choice to elect direct access, if that is their choice. Providing all customer classes with the choice of direct access on day one will stimulate the competitive forces and provide the competition necessary to drive down California's electricity prices.[7]

Availability of direct access for all customers does not mean that every customer who desires direct access will have it on the very first day. As we noted above, there are legitimate concerns about the abilities of the UDCs to process the requests of their customers to switch over to direct access. As a result, backlogs in processing direct access requests may develop, especially in the beginning months. We describe below the direct access implementation plans the utilities will have to submit to us. In those plans, each utility will be required to detail the process and procedures that the utilities will use to manage the direct access requests, and to describe the number of direct access requests it can accommodate in the first month, and in the succeeding months. This data will provide the basis for determining the speed with which direct access requests can be "ramped up.".

Depending on the volume of direct access requests received, limits on the abilities of the UDCs to process those requests may lead to backlogs. However, our direct access implementation procedures will allow us to closely monitor developments, and provide us with the means to intervene quickly to limit the duration of backlogs, including resorting to a limited moratorium on accepting direct access requests, if necessary. This will result in an understandable, manageable, and equitable process for handling direct access requests.

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[7] Section 365(b)(1) provides in part that direct access transactions shall commence simultaneously with the start of the ISO and PX. This "simultaneous commencement shall occur as soon as practicable, but no later than January 1, 1998." Should the ISO and PX be up and running before January 1, 1998, then direct access should also be permitted.

We expect the utilities to handle the processing of direct access requests as expeditiously as possible, and on a first-come, first-served basis. Defining the parameters of what constitutes a valid direct access request should be addressed in the development of the direct access implementation plan described in this section. This could include such things as ensuring that the customer has the necessary metering equipment, that service agreements have or will be agreed to, and for residential and small commercial customers, that the customer's request has been verified. By requiring customers to be "direct access ready" prior to being cut over will act to limit the number of customers that actually choose direct access.

We recognize the difficulties the utilities may face in correctly sizing their procedures for processing direct access requests. Although direct access requests should be processed in a timely manner, we also see no point in the investor-owned electrical corporations having to staff up to a level where a flood of requests are expected, but do not materialize.

In order to reasonably manage the implementation of direct access, we direct investor-owned electrical corporations to submit a direct access implementation plan for the Commission's approval. The direct access implementation plan should detail the process and procedures that the utility will use to manage the direct access transaction requests. The plan shall also include pro forma tariffs which detail the terms and conditions of direct access.[8] The direct access tariffs should assure the seamless provisioning of distribution service to direct access customers. The tariffs should also reflect that the distribution and other services provided to direct access customers shall be provided under equivalent terms and conditions as those provided to non-direct access customers. This plan shall be filed with the Docket Office and served on all parties to this proceeding on or before July 1, 1997. Comments on the plan shall be filed

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[8] We recognize that the terms and conditions of direct access may evolve as more definitive decisions regarding certain aspects of direct access are issued. A process to address the issues associated with the pro forma tariffs shall be established in an assigned Commissioners' ruling or in an ALJ ruling.

on or before July 18, 1997. These plans will be reviewed and acted upon by the second meeting of the Commission in September of 1997.

The investor-owned electrical corporations shall convene, within 30 days of the effective date of this decision, a meeting with the interested parties to address the development of the direct access implementation plans.[9] To the extent that the utilities and market participants can in concert develop an implementation plan acceptable to all or most of the stakeholders, the ability of the Commission to move forward and implement direct access in a reasonable and fruitful manner will be enhanced. The focus of such a meeting should be to develop a consensus as to how direct access customers and providers can make the switch from bundled service to direct access service. Among the other issues to address are the format of the direct access requests, and ways in which electronic means can be used to lower transaction costs and to make the process more efficient and easier for both direct access customers, the electric service provider and the UDC. In addition, such a meeting should address the issue of renewable resources and Section 365(b)(2) in light of the decision not to phase-in direct access.[10]

The utilities shall work with the other participants in formulating their direct access implementation plans. We are hopeful that the UDCs and other market participants can agree on the protocols and policies that will govern the implementation of direct access given our guidance outlined in today's decision. As we look at the tremendous efforts of the WEPEX process, the Public Purpose Working Group, and the DAWG, we are hopeful that market participants and other stakeholders working

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[9] This meeting could be held in conjunction with the workshop on the retail information management plan (RIMP), which is discussed later in this decision.

[10] In implementing Section 365(b)(2), the Legislature clearly expressed a preference for any customer with at least one-half of its electrical load supplied by a renewable resource provider with respect to any phase-in of direct access. In implementing full direct access, this preference should be preserved, and such requests should go to the front of any queue in processing direct access requests.

together can develop rational, effective, and efficient direct access implementation plans.

We adopt the following standards and procedures, which all investor-owned electrical corporations shall follow, to govern the processing of the direct access transaction requests:

- Each UDC will begin accepting direct access requests on November 1, 1997 to become effective on or after January 1, 1998.
- Each UDC will process the direct access requests on a first-come, first-served basis.
- Direct access requests received by the UDC on, or before the 15th of the month will be switched over during the next month's billing cycle. For example, a direct access request received by the UDC on or before December 15, 1997, would be switched over to direct access during the January 1998 billing cycle, and orders received prior to January 15th would be switched to direct access during the February 1998 billing cycle.
- Direct access requests must be submitted in a format acceptable to the UDC.
- If applicable, the direct access requests shall be verified in accordance with Section 366.
- The UDC should implement a means by which direct access requests can be received in an electronic format.
- The utilities shall inform the Commission by letter to the Executive Director and the Director of the Energy Division, when there is a backlog of direct access requests of two weeks or more.
- If the backlog of unprocessed direct access requests grows to 30 days, the affected utility shall notify the Commission, and file within five days, a direct access request backlog reduction plan designed to eliminate the backlog within 90 days. Such a plan cannot seek to reduce the backlog by refusing to accept further bona fide direct access requests. The backlog reduction plan should also address whether Section 365(b)(2) requires that the direct access request from this type of customer be given a priority in processing the backlog.
- The direct access implementation plans of the UDCs should seek to balance the need for speedy and efficient transactions,

while ensuring that there are appropriate safeguards to protect customers from unauthorized or inadvertent changes.

- The UDCs are directed to submit a monthly report starting November 15, 1997, to the Director of the Energy Division and to other interested parties regarding their direct access implementation activities. This report shall include the previous month's activities, consisting of the following:

    1) the number of direct access requests received;
    2) the number of requests processed;
    3) the number of customers switched to direct access;
    4) the number of customers switching direct access providers;
    5) a breakdown of the above data by customer class;
    6) the average backlog of requests during the month; and
    7) the number of customers who request a return to UDC service from direct access.

This reporting requirement shall terminate with the report ending for the month of June 30, 1999. Based on these monthly reports, we can continually monitor the status of the commercial transactions processing and determine whether any limitations on availability of direct access should be imposed. For example, if processing transactions is taking longer than the standards established in the implementation plans, we could consider steps to limit availability of direct access by instituting a limited moratorium on the receipt of requests seeking direct access.

In response to some of the comments on the ALJ's proposed decision, we elaborate on what we expect the implementation plans to include. The plans should describe how many direct access requests the utility will be able to handle in the first month and in each succeeding month. We understand that transactional limitations may exist and have no desire to overwhelm the system. Rather, we will allow each utility to describe in great detail, detail which has not yet been provided by any party, the number of transactions that each UDC can accommodate. Each utility should specify where the potential bottlenecks are likely to occur, for example, is it in meter replacements, or is it in billing conversions. As part of that specification, the utilities should indicate whether they have different capabilities for processing direct access requests based on whether or not the customer requires a new meter, and if so, what those differences are. The utilities should also provide some indication of the lead times they would need to relax or remove the constraints limiting the number of direct access requests they can process. In addition, the utilities may specify in their implementation plans appropriate contingency plans for dealing with the processing of direct access requests in the face of severe weather problems or natural disasters that affect system reliability.

We also intend to address in our next decision other ways in which we can monitor the implementation and success of direct access. Such monitoring devices will allow us to track the progress of direct access, the extent to which there is competition, how well our consumer protection safeguards are working, and the effectiveness of the consumer education efforts.

Since this decision does not adopt an "open season" or "lottery" mechanism to process direct access requests, we are not creating a land rush type of mentality. A land rush mentality would prompt some more cautious customers, who would normally prefer to wait and see how direct access evolves, to hastily queue up for direct access out of fear that if they do not do so, they may not have another opportunity to do so in the near term. By allowing customers to choose when they are ready for direct access, the number of customers seeking early direct access will be reduced naturally without the need for imposing complicated rationing mechanisms.

Transition Emergency Mitigation Plan (TEMP)

In the event that this new electric industry environment cannot handle the volume of direct access transactions, or if the success of the marketplace is threatened in the first 12 months of operation, we recommend that the following procedure be followed. The ISO governing board, with the approval of the Oversight Board, would have the ability to declare an "emergency" and notify the Commission that an emergency exists.[11] An emergency is not meant as the means of addressing problems

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[11] We encourage the ISO to develop specific plans for various contingencies if it thinks such advance plans are needed in order to allow it to react quickly should such a contingency arise.

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with the efficacy or efficiency of the marketplace, but rather refers to the inability of the ISO's procedures and operations to support the various transactions required of the market. Upon the declaration of an emergency by the ISO, the utilities, if requested by the ISO, will institute a 10-day moratorium on processing requests for direct access.

Once the ISO has declared an emergency, we recommend that the ISO inform the Commission as to what, if any, actions the Commission should take to assist the ISO and other participants to alleviate the perceived emergency. Such a notification should explain in detail the nature of the emergency, if direct access should be limited and why, and propose a method of allowing reduced participation. In addition, the plan should specify the steps to be taken to alleviate the problem. The plan would have a maximum duration of 90 days. The plan must preserve the preference for a customer if at least 50% of the customer's direct access load is supplied from a certified renewable resource provider (See Section 365(b)(2).), and must be equitable to all consumer regardless of customer class.

We also suggest that the ISO do whatever is necessary on its end to alleviate the problem as well. In fact, the ISO may be able to resolve the emergency by altering its policies and protocols, especially with respect to the SCs.

Upon the declaration of an emergency by the ISO, the Energy Division shall ensure that a workshop is held in conjunction with the UDCs, the ISO, and all other interested parties to discuss contingency options, and the development of a TEMP. Such a workshop shall be held within five days from the ISO's declaration of an emergency. A workshop report shall be prepared by the UDCs, in conjunction with the other workshop participants, and filed with the Docket Office no later than five days after the workshop.

Should such contingency plans be developed by the ISO, the Commission recommends that the ISO inform the Commission of these contingency plans in advance of such an emergency so that the Commission can react quickly if needed. No contingency plan that limits a customer's participation in direct access will be implemented without this Commission's express approval as a result of the ISO declaring an emergency.

Any TEMP would be put into effect by the Executive Director, subject to later ratification by the Commission. The moratorium on the UDC's processing of the direct access requests could be extended by a ruling of the President of the Commission or his designee.

Except for the ISO, it is not appropriate to give any market participant the unilateral ability to suspend further processing of direct access transactions. Instead, we will allow other market participants, including the UDC and energy service providers, to petition the Commission to implement a TEMP and to propose a mitigation plan. In the event that the Commission concurs with such a petition, we would adopt a specific TEMP consistent with the policies described above.

Metering Requirements For Direct Access

Currently, most electric customers have a standard meter that records the customer's electricity usage and is read on a monthly basis. A small number of customers have time-of-use (TOU) meters that record and store data in specific time intervals. These TOU meters collect data in two intervals, on-peak and off-peak hours. Customers willing to shift their electricity to less expensive time periods, i.e., off-peak hours, benefit from TOU meters because the meters can collect and record the customers' usage in these specific time intervals.

Direct access heralds great changes for electric metering and data communications systems. The immediate problem of permitting direct access is that it affects the type of metering capability that customers need to have in place. Metering technology can facilitate direct access transactions because up-to-date customer use information will aid in more accurate settlements. For direct access to work in conjunction with the ISO, the market requires the ability to account for consumption on a periodic, hourly basis.

When considering whether to provide all customers with the opportunity to choose direct access beginning January 1, 1998, one problem that arises is the impossibility of requiring all customers to have hourly meters by that date. For the investor-owned utilities, there are about 40,000 industrial and large commercial metering locations, 1.5 million commercial and agricultural metering locations, and 8.5 million residential metering locations in California. Of the industrial meters, approximately 50% are capable of supporting the data requirements for direct access, i.e., hourly recording of energy usage. Of the commercial and agricultural meters, only about 10% are presently capable of supporting direct access. Residential meters typically do not support the data requirements of direct access. (August 30, 1996 DAWG Report, p. 8-10.)[12]

In the January 17, 1997 Report on the communications and data systems workshop, Edison stated that should hourly meters for all customers be required, all of its commercial and industrial accounts with a load greater than 50 kW could be metered appropriately by January 1, 1998. This is made up of approximately 45,000 accounts. The remaining 500,000 commercial and 3.5 million residential accounts below 50 kW might encounter difficulty if they were required to have hourly metering by January 1, 1998.

The January 17, 1997 Report noted that PG&E stated that it has about 2500 customers whose load exceeds 500 kW. According to PG&E, most of these customers already have hourly metering capabilities.

Installation of hourly interval meters for all 10 million or so electricity customers in California would require a multi-year effort. In the alternative, thousands of employees would have to be hired to read the existing meters on a daily or hourly basis. Neither alternative is compatible with direct access implementation for all customers on January 1, 1998.

Universal metering as a direct access constraint only exists if no reasonable substitute for hourly interval meters is available. The solution to this problem, as

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[12] According to Cellnet's comments to the ALJ's proposed decision, there are also approximately an additional two million electric meters in California which are served by the municipal utilities.

pointed out by a number of the parties, is to use statistical load profiles for residential and small commercial customers.

As a condition precedent to allowing a customer to participate in a direct access transaction, we shall require that all customer accounts with a maximum demand equal to or greater than 20 kW[13] to have in place a meter which provides, at a minimum, hourly metering.[14] For these customers and their suppliers, the hourly meter will represent a minimum standard for appropriate metering equipment. Customers who do not presently have this hourly metering capability must avail themselves of such meters in order to participate in direct access.[15] The customer shall be responsible for the cost of the meter and meter installation.[16] (See Preferred Policy Decision, pp. 78-79, fn 27.)

We will allow customers whose accounts have a maximum demand of less than 20 kW, to participate in direct access through statistical load profiling, as discussed below. They can also choose to have a meter installed which can provide hourly

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[13] The ALJ's proposed decision had originally recommended that customers with a maximum demand equal to or greater than 50 kW be required to have a meter capable of hourly metering in order to participate in direct access. Several of the parties' comments to the ALJ's proposed decision recommended that this cut-off be lowered to 20 kW to correlate with AB 1890's definition of a small commercial customer, to more closely reflect the current tariff schedules of customer classes, and to lessen the potential for cost shifting that could occur if customers whose maximum demand was 20 kW to 50 kW were able to use load profiles. For those reasons, we have reduced the cutoff point to 20 kW. We will also consider whether load profiles for certain customers whose maximum demand is equal to or greater than 20 kW, but less than 50 kW should be permitted. The possibility of those kinds of exceptions should be addressed in the load profiling workshop discussed later in this decision.

[14] Our reference to the term "hourly metering" or "hourly interval meter" is intended to include existing meters that can be retrofitted to record usage on an hourly basis, hourly meters that can be read monthly or daily, hourly meters capable of being read remotely, hourly meters with two-way communications capabilities, and other metering technologies that might develop.

[15] The issue of master meters and direct access facilities will be addressed in a subsequent decision.

[16] We note that this does not prevent a retailer or other direct access provider from picking up all or part of this cost.

metering.[17] Although it is our intent that statistical load profiling be an interim step towards customers utilizing metering technology that best reflects their consumption, we believe that it is premature to conclude today that load profiles for customers under 20 kW will not accurately reflect consumption. Accordingly, we will not require hourly meters for direct access customers under 20 kW by January 1, 2002 until we have gained some experience with the use of statistical load profiles. We will reevaluate the use of statistical load profiles in the year 2000.

For those customers whose maximum demand is between 20 kW and 50 kW, we will explore possible exemptions from the requirement of having hourly meters. We are concerned that the 20 kW restriction may be too much of a "bright line" and that some degree of flexibility is merited here. Rather than prohibit all customers with a maximum between 20 kW and 50 kW from relying on statistical load profiles, we will consider allowing the development of specific load profiles to include some customers whose maximum demand is at or above 20 kW but below 50 kW. These issues should be explored in the statistical load profiling workshop described below.

Metering Requirements For The Hourly PX Rate Option

The Preferred Policy Decision ordered the utilities to offer the hourly PX rate option, i.e., virtual direct access, by January 1, 1998 and recognized that the availability of this option is dependent on the type of meters that are in place. The hourly PX rate option called for by the Preferred Policy Decision requires the utility to offer to customers a rate option that allows them to purchase electricity at the prevailing PX price. Such a rate option allows individual consumers to participate in the PX market by providing them with the opportunity to reduce their electricity bills by responding to real time prices. For this to occur, hourly interval meters are required.

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[17] A customer whose account has a maximum demand of less than 20 kW may choose to install an hourly meter to take advantage of direct access. In order to participate in virtual direct access, now referred to as the "hourly PX rate option," such customers shall be required to have an hourly meter. The hourly PX rate option allows such customers to purchase electricity on a

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Load profiling cannot be implemented for customers on this rate option because the actual hourly usage must be measured and hourly prices of consumption must be known. That is, if a customer is able to shift its electricity demand to a time period when the hourly PX price is cheaper, such a shift could produce savings for this customer.[18] This change in consumption patterns is the objective of the hourly PX rate option.

Consistent with ALJ Weissman's ruling of January 31, 1997 in the consolidated ratesetting applications, we will defer the development of the hourly PX rate option tariff to that proceeding.

Utility Meter Installation Schedule

In the Preferred Policy Decision, the Commission adopted a five year plan for installing the necessary meters for customers other than those in the categories of Domestic, GS-1, and TC-1.[19] The installation schedule was designed to provide for an orderly approach to installation, and was consistent with the phase-in schedule for direct access. (Preferred Policy Decision, pp. 78-79.) The installation schedule is as follows:

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

Under this schedule, all customers are individually responsible for the cost of the meter installation and the meter. The Preferred Policy Decision also provides that those customers who are not yet scheduled for utility meter installation may purchase and

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rate schedule that is reflective of their usage in real time or time of use increments based on the PX price.

[18] One of the pending issues in the consolidated ratesetting applications, A.96-12-009, A.96-12-001, and A.96-12-019, commonly referred to as the unbundling proceeding, is whether the rate freeze prohibits any actual bill savings from occurring.

[19] The Preferred Policy Decision allowed these three customer groups to voluntarily install such meters if they elect to participate in direct access, or avail themselves of the virtual direct access billing option. (Preferred Policy Decision, p. 78.)

install such meters at their own expense, and could opt to have the meters installed by others. (Preferred Policy Decision, p. 79.)

The metering installation schedule that we outlined in the Preferred Policy Decision should be deferred. The issue of whether the utilities should be required to install all of the meters is central to much of the discussion in the so called "revenue cycle unbundling" proceeding. If metering is allowed to be unbundled in that proceeding, the issues of who will install these meters, and the ownership of such meters, will have to be addressed in another decision. In addition, all non-load profile customers who want to participate in direct access, or who want to avail themselves of the hourly PX rate option, i.e., virtual direct access, are required by this decision to install hourly interval meters. This should accelerate the installation of hourly meters.

We note that Section 378 provides:

> "The commission shall authorize new optional rate schedules and tariffs, including new service offerings, that accurately reflect the loads, locations, conditions of service, cost of service, and market opportunities of customer classes and subclasses." (Emphasis added.)

Section 378, as added by AB 1890, prevents us from requiring all customers to shift to an hourly rate. We can only require that utilities offer this as an option to their customers. Under the meter installation schedule of the Preferred Policy Decision, those customers who decide to stay on the UDC flat rate option would be forced to pay for a meter that they do not need.

We are also concerned that the Preferred Policy Decision's mandate that each customer must have an hourly meter could run afoul of Section 368(a) which prohibits rates to consumers from being raised. The Preferred Policy Decision would require that customers pay for the meters that the Commission mandated be installed. Customers that do not choose either direct access or the hourly PX rate option would be paying for a meter and function that they do not need. Some could argue that this constitutes a rate increase which is prohibited under Section 368.

Given the many questions raised by the Preferred Policy Decision's mandate regarding meter installation, and the policies of today's decision which mandates that all direct access customers with a demand greater than or equal to 20 kW have hourly meters and that all hourly PX rate customers have hourly meters, the reasonableness of requiring the utilities to install hourly meters for all 500 kW and above customers by January 1, 1998 is questionable. Therefore, we shall suspend the mandatory metering requirements of the Preferred Policy Decision until the Commission can further assess the need for mandatory hourly meters for customers. Before deciding whether mandatory metering should be reinstated, the Commission should examine the rate at which hourly meters are being installed, the participation rate for direct access, and the participation rate in the hourly PX rate option. These market forces may eliminate the need to impose any mandatory meter installation schedule.

Metering Standards

Irrespective of whether the Commission approves unbundling and the competitive provisioning of metering and metering services, it is prudent for us to require parties to meet to discuss open architecture standards. Metering standards are necessary to ensure that the customer's meter is capable of interfacing with the meter reading equipment of the UDC, or if such service is unbundled, that it is capable of being read by another meter reading provider. Standards are also needed to ensure the efficiency, reliability, compatibility, and safety of these metering systems. These include such things as standards for meter reading accuracy and timeliness, and the transferring of meter data to other parties.

We will direct the Energy Division staff to ensure that a workshop with the UDCs and interested parties is held within 45 days of the effective date of this decision. The workshop shall address technical specifications for metering and metering communication standards, as well as protocols, and any necessary certification requirements and procedures. As discussed in D.96-10-074, we favor an open architecture standard that leaves room for technological advances.

A workshop report shall be prepared by the UDCs, in conjunction with the other workshop participants, along with their recommendations, and filed with the Commission within 70 days of the effective date of this decision. That workshop report shall be served only on the participants attending the workshop, on the assigned Commissioners and ALJ, and anyone else requesting a copy. Comments to this report may be filed within 85 days of the decision's effective date, and served on the same parties.[20] Depending on the workshop report's recommendations, the Commission shall either issue a decision or the assigned Commissioners may issue a ruling on the issues raised in this report.

Statistical Load Profiling

A statistical load profile is an estimate of a group of customers' (usually by customer class) hourly consumption over a given period of time. This is a statistical sampling technique which allows customers with load variances to be represented by a single measurement. The load profile will be used by the scheduling coordinator or marketer to determine the customer's hourly consumption. The load profile will also be used by the ISO to determine the generation the scheduling coordinator must provide. Essentially, the load profiles affect the accuracy and fairness of the settlement process, which is within the purview of the ISO.

We will allow residential customers, small and medium size commercial and agricultural customers, and other customers, whose accounts have a maximum demand of less than 20 kW to engage in direct access transactions through use of statistical load profiles.[21] The ability to use statistical load profiles to estimate the hourly consumption of small accounts, instead of requiring hourly interval meters for all direct access contracts, will facilitate the aggregation of small accounts and small customers. Aggregation may be an effective method of providing residential and small to medium size commercial customers with direct access service.

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[20] Unless otherwise noted, the same limited service requirement shall apply to all the other workshop reports and comments to the workshop reports that have been ordered in this decision.

[21] As stated in footnote 13, we will also consider whether load profiles for certain customers whose maximum demand is equal to or greater than 20 kW, but less than 50 kW should be permitted.

The use of statistical load profiles will enable retail providers to accommodate residential and small commercial direct access customers that have traditional monthly meters. Instead of being billed on the customer's actual electric consumption during the month, the customer will be billed based on an authorized statistical load profile for that type of customer.

Although most parties support the concept of statistical load profiling, there are differences of opinion regarding how the statistical load profiles should be designed. Statistical load profiles are estimates of the loads of a group of customers. Those estimates can be fairly accurate if they are based on an appropriate statistical sampling of customers, actual interval metering of some representative portion of the members of the group, and updated frequently. They can be less accurate if they are based solely on literature studies and are not adjusted to reflect actual usage from members of the group in question.

On balance, we believe the use of load profiling will greatly enhance the opportunities for customers to participate in the direct access market. While inaccuracies are inevitable, the marketplace should incorporate the risks and provide an incentive for direct access aggregators to improve data collection.

In order to provide residential, small commercial and agricultural customers, and other customers, whose accounts have a maximum demand of less than 20 kW with the ability to select direct access, the Energy Division staff should ensure that a workshop is held in conjunction with the UDCs and interested participants, including members of the DAWG and the Ratesetting/Unbundling Working Group, and the parties to the unbundling proceeding, to develop statistical load profile methodologies. The workshop should also address whether load profiles should be developed for certain kinds of customers whose maximum demand is equal to or greater than 20 kW but less than 50 kW, a process for updating and revising the statistical load profiles, and ways in which the effects of inaccurate load profiling can be mitigated. We realize that these issues may be contentious. A ruling may be issued before the workshop to help narrow the focus of the workshop, and to request written comments on certain topics. The workshop should be held within 30 days from the effective date of this decision.

The workshop should attempt to come to an agreement on undisputed load profiling issues, as well as disputed issues.

A workshop report shall be prepared by the UDCs in conjunction with the other workshop participants that discusses the areas of agreement and disagreement, what issues require evidentiary hearings, and the parties' recommendations. That workshop report shall be filed with the Docket Office within 40 days of the effective date of this decision. Comments to the workshop report shall be filed within 55 days of the decision's effective date. If evidentiary hearings are requested, the comments shall include a proposed evidentiary hearing schedule and the number of witnesses the party intends to call. If hearings are needed, a ruling on the schedule will be issued the week of June 16, 1997.[22]

Due to the January 1, 1998, implementation date, if hearings are needed, they should take place either during the week of July 21, 1997, or July 28, 1997. Prepared testimony on the load profiling issues would be due sometime during the week of June 30, 1997, and reply testimony during the week of July 14, 1997.

Some of the parties who commented on the ALJ's proposed decision suggest that load profiles be used only on an interim basis. They contend that if load profiling is made permanent, that this will discourage efficient energy consumption because customers will not be changing their usage in response to price signals. In addition, the permanent use of load profiling results in cost shifting among customers and customer groups.

We intend to study how load profiling works out over time. Should adjustments be needed for this aspect of direct access, we will make those adjustments. It is premature at this time to state that load profiling should be limited to an interim period only.

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[22] No evidentiary hearing will be held unless the party requesting such a hearing can demonstrate that a material issue of fact needs to be resolved by the Commission.

Aggregation Of Customer Loads

Access to aggregation may be the only feasible way in which small customers can participate in, and benefit from, direct access. Aggregation also allows a customer with multiple locations to aggregate all of their own loads. A typical aggregation arrangement is likely to involve the provider arranging the following for all of its aggregated customers: generation, distribution services, ancillary services, and, potentially, revenue cycle services. Through aggregation, the transaction costs of direct access can be reduced. In addition, aggregation may allow individual customers to increase their market leverage by aggregating their total demand.

AB 1890 specifically permits the aggregation of customer load. Section 366 provides in pertinent part:

> "(a) The commission shall take actions as needed to facilitate direct transactions between electricity suppliers and end use customers. Customers shall be entitled to aggregate their electric loads on a voluntary basis, provided that each customer does so by a positive written declaration. If no positive declaration is made by a customer, that customer shall continue to be served by the existing electrical corporation or its successor in interest.
>
> "(b) Aggregation of customer electrical load shall be authorized by the commission for all customer classes, including, but not limited to small commercial or residential customers. Aggregation may be accomplished by private market aggregators, cities, counties, special districts or on any other basis made available by market opportunities and agreeable by positive written declaration by individual consumers.
>
> "(c) If a public agency seeks to serve as a community aggregator on behalf of residential customers, it shall be obligated to offer the opportunity to purchase electricity to all residential customers within its jurisdiction."

We will therefore permit all customers interested in participating in direct access transactions to aggregate their own loads or combine their load with other customers through an aggregator. The term "aggregator" is defined in Section 331(a) as:

> "any marketer, broker, public agency, city, county, or special district, that combines the loads of multiple end-use

> customers in facilitating the sale and purchase of electric energy, transmission, and other services on behalf of these customers."

As discussed in the registration portion of this decision, if these aggregators offer electrical service to residential and small commercial customers, they will have to register with the Commission. In addition, each customer must agree to the aggregation by providing a "positive written declaration" to the aggregator.[23]

The next issue with respect to aggregation is how should the aggregators be allowed to combine their customers' load. Several models have been proposed. The first allows for aggregation to be unrestrained in the geographic area served, or affiliation. The second model requires aggregators to be confined to specific service areas in order to solve data problems related to the allocation of settlement costs. The third suggestion is that aggregation be allowed based upon the affinity of the end-users. The fourth alternative is a two step process where the UDC acts as a market facilitator for other aggregators, and eventually, in the post-transition era, the UDC may act as a private aggregator, subject to certain rules and conditions that the Commission may impose on the UDCs to address potential market power issues. (See Affiliate Transactions section.)

We believe that all customers and retail providers should be allowed to aggregate their loads in whatever fashion they can arrange, so long as the settlement procedures are capable of accurately calculating who is responsible for what.[24] The details of those settlement procedures are best left to the parties to work out.[25]

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[23] We agree with TURN's comments to the ALJ's proposed decision that depending on how the "positive written declaration" requirement is worded, such a declaration could serve as the "document fully explaining the nature and effect of the change in service" described in Section 366(d)(3) for small commercial customers, or such a declaration can be used in conjunction with Section 366(e)(4) for residential customers.

[24] There is a need to ensure that aggregators cooperate with the UDCs and the scheduling coordinators since the aggregators and the UDCs will be sharing their loads on common transmission and distribution facilities.

[25] As noted below, a workshop will be held on the CEC's suggestion that a retail information management plan be adopted. Parties could address these kinds of issues at that workshop, or they can endeavor to resolve these issues earlier.

What Are Consumers' Choices?

Approval of direct access does not mean that all customers must participate in direct access. Nor does it mean that consumers have to elect direct access on or after January 1, 1998.

Those customers who want direct access will have to take affirmative steps to effectuate their direct access option. For large commercial and industrial customers that means entering into direct access contracts with various entities offering electric services. AB 1890 does not address the method by which these types of customers can initiate a change in provider. For large commercial and industrial customers, we will leave it up to the marketplace and the entities to decide what type of procedures end-use customers need to follow in order to exercise their direct access option. The methods and procedures for such a changeover from a utility to a direct access customer shall be spelled out in the direct access implementation plan discussed earlier.

With regard to small commercial customers and residential customers, Section 366 describes the procedures that must be followed before the customer's electricity provider can be changed.[26] For small commercial customers, the procedure is as follows:

> "(d) No electric utility, or any person, firm, corporation, or governmental entity shall make any change or authorize a different electric utility or electric marketer to make any change in the aggregator or provider of electric power for any small commercial customer until one of the following means of confirming the change has been completed:
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> > "(1) Independent third-party telephone verification.[27]
> >
> > "(2) Receipt of a written confirmation received in the mail from the consumer after the consumer has

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[26] In its comments to the ALJ's proposed decision, the Merced Irrigation District raised the question as to whether the procedures set forth in Section 366(d) and (e) apply to it if a small commercial or residential customer of PG&E elects to take electrical service from it. Those subdivisions do apply in such instances.

[27] Section 366(d)(1) is unclear whether the independent third-party verification was intended to refer to the independent third-party verification company referred to in Section 366(e). We assume that it did, and therefore the verification required under Section 366(d)(1) shall follow the procedures set forth in subdivisions (e)(1), (e)(2) and (e)(3) of Section 366.

received an information package confirming the telephone agreement.

"(3) The customer signs a document fully explaining the nature and effect of the change in service.

"(4) The customer's consent is obtained through electronic means, including but not limited to, computer transactions.

We expect all electrical corporations, and other entities offering electrical service, as well as their agents or employees to follow Section 366(d) when they encounter a small commercial customer who wants to change its provider of electric service. Failure to abide by this provision could lead to sanctions up to and including the revocation of the entity's registration number, as discussed later in this decision, or if it is an electrical corporation subject to our jurisdiction, to a revocation of the utility's certificate of public convenience and necessity, as well as any applicable fines and penalties.

Any change in a residential customer's aggregator or provider of electric power must follow the procedures set forth in Section 366(e):

> "(e) For residential customers no change in the aggregator or provider of electric power may be made until the change has been confirmed by an independent third-party verification company, as follows:
>
> "(1) The third-party verification company shall meet each of the following criteria:
>
> "(A) Be independent from the entity that seeks to provide the new service.
>
> "(B) Not be directly or indirectly managed, controlled, or directed, or owned wholly or in part, by an entity that seeks to provide the new service or by any corporation, firm, or person who directly or indirectly manages, controls, or directs, or owns more than 5 percent of the entity.
>
> "(C) Operate from facilities physically separate from those of the entity that seeks to provide the new service.
>
> "(D) Not derive commissions or compensation based upon the number of sales confirmed.

> "(2) The entity seeking to verify the sale shall do so by connecting the resident by telephone to the third-party verification company or by arranging for the third-party verification company to call the resident to confirm the sale.
>
> "(3) The third-party verification company shall obtain the resident's oral confirmation regarding the change, and shall record that confirmation by obtaining appropriate verification data. The record shall be available to the resident upon request. Information obtained from the subscriber through confirmation shall not be used for marketing purposes. Any unauthorized release of this information is grounds for a civil suit by the aggrieved resident against the entity or its employees who are responsible for the violation.
>
> "(4) Notwithstanding paragraphs (1), (2), and (3), a service provider shall not be required to comply with these provisions when the customer directly calls the service provider to make changes in service providers. However, a service provider shall not avoid the verification requirements by asking a customer to contact a service provider directly to make any change in the service provider. A service provider shall be required to comply with these verification requirements for its own competitive services. However, a service provider shall not be required to perform any verification requirements for any changes solicited by another service provider."

Our reading of Section 366(e) leads us to believe that the entity seeking to provide the service to a residential customer must have the change confirmed by an independent third party verification company before it can become the provider of electric service for a residential customer. (Section 366(e)(2) and (e)(4).) The residential customer can also call the existing service provider directly to request a change to a new service provider. In such a case, the existing service provider who is losing that customer need not confirm that change through the use of an independent third party verification company. (Section 366(e)(4).)

As noted above, we also expect all electrical corporations, and other entities offering electrical service, as well as their agents or employees to follow the provisions of Section 366(c) when dealing with residential customers who want to change their aggregator or electric power provider.

We do not intend to require registration of the independent third-party verification companies, or to get involved in a discussion of who should pay these companies. The service providers themselves need to ensure that the verification companies meet the criteria in Section 366(c)(1), and that they maintain the paperwork necessary to confirm that the customer did indeed verify a change of provider. Should problems arise over whether a residential customer or small commercial customer was switched by another company without the customer's consent, i.e., "slammed," we intend to focus our inquiry on whether the "new" electric service provider properly followed the provisions of Section 366.

Those customers who do not want to engage in a direct access transaction will not have to do anything on their part. The role of the UDC is to provide distribution services to all customers regardless of their choice of electricity supplier. (Preferred Policy Decision, p. 85.) In addition, the UDC will be required to supply electricity to those customers who choose to remain with their existing electric utility. During the four year transition period, the three largest UDCs must bid all their generation into the PX and purchase power on behalf of the utility service customers from the PX. (D.96-12-088, pp. 7, 42; Preferred Policy Decision, pp. 51, 57, 70.) As the distribution entity, the UDC shall be responsible for providing distribution services to customers, and shall also be responsible for service connection and disconnection.[23] The Commission will continue to regulate the rates, terms, and conditions of the distribution and electric services provided by the UDC including, their ability, if any, to engage in competitive market services and transactions in the post-transition era. (Preferred Policy Decision, pp. 70, 72,87.) We shall presume that a customer who does

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[23] The responsibility for service connection and disconnection may change if metering services are unbundled.

not initiate the process needed to change its provider will, by default, be provided power by the UDC with energy purchased from the PX.

Customers who choose the direct access option, as well as customers who do not choose direct access, have the obligation to pay the transition costs provided for in Sections 367, 368, 375, and 376.[29] These costs are to be paid to the electrical corporation providing electricity service in the area in which the consumer is located. To the extent that the customer does not use the electrical corporation's facilities for direct access, the electricity marketer must advise the customer to confirm in writing that the customer is obligated to pay these transition costs. (Section 370.)[30]

We next address the issue of whether the UDC is obligated to serve as the default provider for a customer formerly served by a non-UDC electric service provider.

The idea of the UDC serving as the default provider is to ensure that everyone is provided with electricity, because electricity is an essential commodity. Anyone who pays for the service should be allowed access to it. Accordingly, the UDC shall be obligated to serve any customer who no longer engages in direct access.

We will, however, require that the customer seeking a return to the UDC provide the UDC with adequate notice, if needed by the UDC. In addition, if it is a residential or small commercial customer, the provisions of Section 366 need to be met as well. Advance notice may be required so that the UDC can accommodate the return. We shall leave it up to the UDCs to decide whether their tariffs, which are subject to the Commission's approval, need to include a reasonable notice requirement. We would

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[29] AB 1890 specifically exempts certain kinds of transactions from the payment of any transition costs. For example, transition costs "shall not be recoverable for new customer load or incremental load of an existing customer where the load is being met through a direct transaction and the transaction does not otherwise require the use of transmission or distribution facilities owned by the utility." (Section 369.) Another exemption is provided for in Section 374, which exempts certain kinds of transactions with irrigation districts from the transition costs.

[30] The requirement that marketers inform customers of the written confirmation requirement terminates on January 1, 2002. (Section 370.)

expect that it would be no harder or easier to return to the UDC than to switch to direct access in the first place since the UDC can turn to the PX for all of its power needs.

Retail Information Management Plan

The CEC has suggested that a stakeholder group be formed to develop a retail information management plan (RIMP). The group's purpose would be to address the information flow needs of the restructured electric industry. In particular, the CEC believes that there needs to be a common understanding of the retail functions of the scheduling coordinator, and the type of information flow needed to support the settlement process between the scheduling coordinators, the UDCs, the electric service providers, and end-use customers. For example, the scheduling coordinator will need to be able to track individual hourly schedules at all energy receipt and delivery points it uses. The CEC contends that an awareness of these topics is essential to the operation of this new electric market structure.

We agree with the CEC that protocols are needed to govern how the retail side of the settlement process will interface with the scheduling coordinators. All of these parties, as well as the Commission, need to develop an understanding of the information flows needed, and agree upon how settlements will be conducted. The lack of such understanding can lead to commercial disputes, which may add unnecessary cost and delay to the implementation of direct access and restructuring in general.

Therefore, the Energy Division shall ensure that a workshop is held in conjunction with the UDCs, and other interested persons, within 60 days from the effective date of this decision, to address these retail settlement and information flow issues.[31] Parties should consider the settlement and information flow issues related to the ISO and SCs, and where appropriate, use consistent methods. The workshop should also examine how the settlement procedures can resolve problems that may occur with respect to aggregated loads. The workshop should also explore whether the use of

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[31] The direct access implementation plans of the UDCs could be integrated into the RIMP.

meters at the transmission and distribution nodes will help to lessen the settlement imbalances.

A workshop report shall be prepared by the UDCs, in conjunction with the other workshop participants, and filed with the Commission's Docket Office within 80 days of the decision's effective date. The report should discuss the settlement and information flow issues and any issues which require the Commission's further consideration. Comments to this report may be filed within 95 days of the decision's effective date. Depending on the issues raised in the workshop report, the Commission may issue a decision or the assigned Commissioners may issue a ruling on the issues raised in this report.

Market Rules

Introduction

As indicated at the beginning of the decision, the market rules described below are the threshold issues that need to be decided in a timely manner. We anticipate that in the next decision on direct access, which is to be issued shortly, a more comprehensive set of rules will be adopted.

Non-utility Electric Service Provider Registration Of Retail Providers

Position Of The Parties

Should the Commission adopt market rules for non-utility electric service providers? Opponents of such rules fear that this will subject them to the jurisdiction of this Commission. Proponents of such measures argue that market rules are needed to protect consumers. The Energy Producers and Users Coalition and the Cogeneration Association of California (EPUC/CAC) assert that this Commission does not have jurisdiction over non-utility electric service providers. They contend that AB 1890 makes clear that non-utility electric service providers are not public utilities, and therefore are not subject to the jurisdiction of this Commission. As a result, they assert that the DAWG recommendations regarding regulations should not apply to them. The comments by the other electric service providers echo the same arguments.

Assuming that the Commission has jurisdiction over non-utility electric service providers, EPUC/CAC argues that the Commission would have only limited oversight responsibilities. They contend that only AB 1890 gives the Commission responsibility in the following areas.

First, the Commission has responsibility for verification of service elections and discontinuations. (Section 366(d).) Second, Section 394(a) requires that non-utility service providers offering service to residential and small commercial customers register with the Commission. Third, Section 394(b) requires that each entity offering electric service to residential and small commercial customers provide those customers with a written notice about the price, terms, and conditions of service, an explanation of the competitive transition charge and its amount, and a notice describing the customer's right to rescind a contract. The Commission is given the authority to assist in developing such notices, and may suggest the inclusion of additional customer information. Fourth, Section 394(c) provides that the Commission accept, compile, and help resolve consumer complaints with registered service providers.[32] And fifth, AB 1890 allows customers to cancel their electric service contracts under specific circumstances.

The CEC asserts that prudent consumer safeguards do not stifle competition. Unless there are effective registration requirements, wary consumers will tend to stay with the familiar. The CEC believes that the Commission should adopt prudent regulatory measures to reduce the potential for obvious market abuses.

Edison acknowledges that electric service providers are not necessarily public utilities, and therefore not subject to the plenary ratemaking authority of the Commission. But given the legislature's intent that consumers be provided with mechanisms to protect them from marketing abuses, Edison recommends that the Commission presume that AB 1890 gives the Commission broad statutory authority for

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[32] EPUC/CAC also contend that AB 1890 does not provide the Commission with any authority to hear or resolve such complaints.

assuring consumer protection. Edison believes that registered electric service providers should be required to display a Commission registration number in their advertising and other customer communications.

The Office of Ratepayer Advocates (ORA) contends that the Commission can impose more stringent registration requirements than AB 1890 requires. ORA also believes that the Commission should clarify and exercise its authority over electric service providers in the area of customer complaints, and establish rules governing customer relations with respect to electric service providers.

SDG&E believes that AB 1890 gives the Commission the responsibility to implement a system to register retailers. Although the legislation does not define what comprises electrical service, SDG&E contends that it is reasonably clear that brokers, marketers, and aggregators should be required to register. SDG&E believes that this registration requirement should be interpreted to encompass a retailer providing not only direct access, but other electric services as well. For example, SDG&E believes that the legislature did not intend to distinguish between direct access and virtual direct access in defining registration requirements. Nor did the legislature intend to distinguish between those who supply electricity and those who supply energy efficiency programs only. SDG&E asserts that all of these entities are providing electrical service and all should be covered by the registration program.

SDG&E cautions, however, that many of the parties seek to use the Commission as a vehicle to impose additional regulation on jurisdictional utilities, and to place impermissible regulations on non-jurisdictional entities. SDG&E believes that consumer education is the most direct form of protection.

Discussion

We believe that there is a need to establish some kind of market rules regarding non-utility electric service providers. These market rules will be the ground rules that all similarly situated entities must adhere to if they wish to participate in the restructured electricity market. The creation of such market rules is authorized under AB 1890 to ensure that consumers are protected. (See Stats. 1996, ch. 854, Section 1(d), p.

4; Section 10, p. 51.) As we noted in the Preferred Policy Decision, "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." (Preferred Policy Decision, p. 188.) Some amount of regulatory oversight is needed over market participants to ensure that consumers are protected from unscrupulous operators. In deciding what sorts of rules we should impose on entities entering into the market, one thing is clear. AB 1890 requires that the Commission establish a registration system for "each entity offering electrical service to residential and small commercial customers within the service territory of an electrical corporation." (Section 394(a).)

The Legislature appears to have intended that only those entities offering electrical service to residential and small commercial customers need to register with the Commission.[33] There is no requirement in AB 1890 that those entities offering electrical service to large commercial customers and industrial customers need to register with the Commission. We can only surmise that the reason for this distinction is that the Legislature felt that these large commercial and industrial customers have the experience and the means of finding out who they are dealing with. Thus, in developing our registration rules, only those entities offering electrical service to residential and small commercial customers need to register with the Commission. Should the large commercial and industrial customers participating in this proceeding feel that there is a need for registration of the entities offering electrical service to them, they should consider seeking legislation to amend the applicable code sections.

In discussing the registration procedures, we raise one issue that the governing boards of the publicly owned electric utilities might want to consider. Section 394(a) provides that only those entities offering electrical service in the service territories of the electrical corporations subject to our jurisdiction are required to register with the

[33] The term "small commercial customer" is defined in Section 331(h) as "a customer that has a maximum peak demand of less than 20 kilowatts."

Commission. AB 1890 does not require registration with this Commission of electric service providers offering electrical service in the service territories of the publicly owned electric utility.

The next issue regarding registration is what kinds of entities are required to register. That is, what is meant by an "entity offering electrical service?" In order to determine this, we must look at the types of services that are likely to be offered in the restructured electricity market. Residential and small commercial customers are likely to encounter marketers of electricity, brokers who will arrange the sale and purchase of electricity, and the UDC.[34] They might also encounter an aggregator who is a marketer or broker. These customers might also encounter an entity offering only energy efficiency or load management services.

A "marketer," as defined in Section 331, is clearly an entity offering electrical service. Section 331(e) defines a marketer as "any entity that buys electric energy, transmission, and other services from traditional utilities and other suppliers, and then resells those services at wholesale or to an end-use customer."

Whether an "aggregator" and a "broker" are considered to be entities offering electrical service is a much tougher question to answer. An aggregator is defined to mean "any marketer, broker, public agency, city, county, or special district, that combines the loads of multiple end-use customers in facilitating the sale and purchase of electric energy, transmission, and other services on behalf of these customers." (Section 331(a).) A broker is defined as "an entity that arranges the sale and purchase of electric energy, transmission, and other services between buyers and sellers, but does not take title to any of the power sold." (Section 331(b).)

Subdivision (d) of Section 1 of AB 1890 states in pertinent part that "[i]t is the intent of the Legislature to protect the consumer by requiring registration of certain sellers, marketers, and aggregators of electricity service. . . ." Thus, an aggregator would be subject to the registration requirements of Section 394. Accordingly, any broker "that

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[34] The UDC is exempt from the registration procedures set forth in Section 394. (Section 394(a).)

combines the loads of multiple end-use customers" would be subject to the registration requirement as well. Basically, if you offer retail electric service to small commercial or residential customers you are required to register with the Commission.

In the event that there are brokers serving residential and small commercial customers who are not combining the loads of their customers, we believe that in order to protect these kinds of customers, those brokers should be subject to the registration requirements of Section 394 as well. As D.97-02-021 at page 46 recognizes:

> "Although marketers, brokers and aggregators are exempted from our jurisdiction as public utilities as defined by Public Utilities Code Section 218 . . . , AB 1890 has given the Commission jurisdiction over these entities as energy service providers for purposes of consumer protection. . . . Further, the Legislature believed that in order to protect the consumer, it was important to require that energy service providers be required to register."

The next issue we address is whether an entity that offers energy efficiency services, or similar types of services, to residential and small commercial customers is considered under Section 394(a) to be an entity offering electrical service.

Section 394(b) provides that an entity offering electrical service shall provide a written notice to its customers about the competition transition charge, and a notice regarding the customer's right to rescind a contract, among other things. This indicates to us that the Legislature intended that it meant to register only those entities offering end-use customers the commodity of electrical energy. Energy efficiency and load management services, as we currently view them, do not fall into that category. Accordingly, those types of entities do not have to register with the Commission pursuant to Section 394.[35]

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[35] We will continue to monitor the development of the market for services such as energy efficiency and load management, and similar types of services, and the relationship between the providers of such services and the electric service providers. The Commission may need to revisit this issue as the market for such services matures.

The next registration issue to address is what type of information the registrants have to provide. Section 394(a) provides that:

> "The registration shall include the following seller information:
> (1) Legal name.
>
> (2) Current telephone number.
>
> (3) Current address.
>
> (4) Agent for service of process."

One school of thought is that the Commission should only impose minimal registration requirements. This view would include only the four items mentioned in Section 394(a).

Another view takes the position that more stringent registration requirements should be imposed so as to protect consumers from marketing abuses. Some parties suggest that the registrants be required to adhere to an industry code of conduct. Another suggestion is to have the registrant post a bond in a sufficient amount to protect customers from financial exposure as a result of a default.

We believe we have the authority to impose additional reasonable conditions related to registration beyond the minimum requirements listed in Section 394(a). Section 394(a) contains the phrase "The registration shall include the following...." That language does not preclude us from including additional registration requirements. The phrase "shall include" should not be construed as words of limitation, but rather, should be viewed in light of the Legislature's intention. (See *Ornelas v. Randolph* (1993) 4 Cal.4th 1095, 1101; *Abbett Electric Corporation v. Storek* (1994) 22 Cal.App.4th 1460, 1470.) The Legislature's stated intent is to protect the consumer by requiring registration of certain sellers, marketers, and aggregators. (Stats. 1996, ch. 854, Section 1(d), p. 4.) Consumers should be provided with the mechanisms necessary to protect themselves from unfair or abusive marketing practices. (See Section 392(b).)

On the requirement of an agent for service of process, we shall require that the agent be located in California.

We will defer consideration as to whether an industry code of conduct and a bonding requirement should be imposed on those entities offering electrical services to residential and small commercial customers to the upcoming decision on consumer protection. With our other market rules, consumer protection rules, and the requirements of AB 1890, it may not be necessary to mandate a bonding requirement, or to develop a separate set of conduct rules.

In addition to the four listed items, we will require the following to be included on the registration form: (a) the type of entity; (b) if the registrant is a corporation, the state in which the registrant is incorporated, and the names and titles of the corporate officers; (c) if the registrant is a sole proprietorship or partnership, the county in which the fictitious business name statement has been filed, if applicable; (d) if a partnership, the names of all the general partners; (e) if a limited liability company, the names and titles of all the managers and/or officers; (f) the address and telephone number of the registrant's principal place of business, if different from the current address and telephone number; (g) the name, title, address and telephone number of the person to whom correspondence or communications regarding customer complaints are to be addressed, and if applicable, the facsimile number and e-mail address; (h) whether the entity has been certified as a renewable resource provider pursuant to Section 383; and (i) whether the registrant, or any of the general partners, or corporate officers, or managers, or officers of a limited liability company ever been convicted of any felony. The registration form shall also be verified as follows:

(1) If the registrant is an individual or sole proprietorship, by the individual or sole proprietor.

(2) If the party is a corporation, limited liability company, trust, or association, by an officer.

(3) If a party is a partnership or limited partnership, by a partner or general partner, respectively.

(4) If the party is a governmental entity, by an officer, agent, or authorized employee.

If the registration form is verified outside California, the verification must be made by an affidavit sworn or affirmed before a notary public.

The California Legislature is also considering some other bills which would require registrants to disclose other items on the registration form. Should these additional items be added in the future, the Commission may require registrants to supplement or update their registration form.

A sample registration form is attached to this decision as Appendix B. This form shall be reproduced by the Commission staff and disseminated to all persons requesting the form. This form shall be completed by all entities registering with the Commission pursuant to Section 394(a). We shall also impose a nominal registration fee of $100 upon each registrant to reimburse the Commission for part of its processing costs.[36] The registrant shall be obligated to inform the Commission in writing within 30 days of any changes to the registration form.

In order to protect residential and small commercial customers from unfair or abusive marketing practices, the additional registration requirements listed above should be imposed. These additional requirements on the registrants are outweighed by the public interest. These registration requirements will ensure accountability by these non-utility electric service providers, and ensure that residential and small commercial customers have adequate recourse in the event the provider fails to perform.

In accordance with Section 394, we will require all aggregators, brokers, marketers, and other entities offering electrical service to residential and small commercial end-use customers, to register with the Commission.[37] An electrical corporation, as defined in Section 218, is exempt from these registration requirements. In accordance with Section 396(d), this registration requirement shall terminate on January 1, 2002, unless extended by a later enacted statute.

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[36] The Commission currently charges an applicant fees ranging from $75 to $1000 depending on the type of authority the applicant is seeking.

[37] This registration requirement also applies to schedule coordinators acting as an aggregator, broker, marketer, or other entity offering electrical service to residential or small commercial end use customers.

The Commission's Energy Division will begin accepting the registration forms starting on July 1, 1997. If additional clarification of the registration process is needed, the Energy Division Director shall clarify the details and provide these details to the service list and others who request it, no later than June 1, 1997. These details should also be posted on the Commission's Internet web site.[38] Upon registration, the Energy Division shall issue a registration number to each registrant.

The Commission may revoke the registration number if the registrant fails to abide by any of the market rules or consumer protection rules adopted in this proceeding, or violates any other statutory provisions governing its conduct.[39] The Commission may also bring civil or criminal actions against the registrant pursuant to the provisions of Sections 2101, 2111, and 2112.[40] We raise this warning as a caution to any potential registrant who may be intent on "slamming" electric customers or engaging in other kinds of questionable behavior.

We shall direct the Executive Director to take all the necessary steps to ensure that the Commission staff has the necessary support mechanisms in place by July 1, 1997, to undertake this registration procedure. In developing these support mechanisms, the staff should keep in mind that this registration information should be readily accessible to the public. The Commission will also monitor whether the registration requirements imposed by AB 1890 result in a need for additional funding to carry out these provisions.

Written Notice Of The Price, Terms, And Conditions Of Service

Section 394(b) states:

> "Except for an electrical corporation as defined in Section 218, each entity offering electrical service to residential and small commercial customers with[in] the service territory of an electrical corporation shall, at the time of the offering,

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[38] The Commission's web site address is: www.cpuc.ca.gov.

[39] As part of our consumer protection rules, we favor a requirement that registrants be required to list their registration number on any advertising or marketing information.

[40] The failure to register under Section 394 could also trigger the exercise of these provisions.

> provide the potential customer with a written notice describing the price, terms, and conditions of the service, an explanation of the applicability and amount of the competition transition charge, as determined pursuant to Sections 367 to 375, inclusive, and a notice describing the potential customer's right to rescind the contract. The commission shall assist these entities in developing the notice. The commission may suggest inclusion of additional information that would be useful to the customer."

As part of the market rules which we adopt today, each entity who is registered pursuant to Section 394 shall, at the time of offering the electrical service, provide the notice described in Section 394(b). The notice described in that subdivision actually refers to two different types of notice. The first is that the notice must describe the price, terms, and conditions of the service, as well as an explanation of the applicability and amount of the competition transition charge. The second notice referred to in Section 394(b) is "a notice describing the potential customer's right to rescind the contract." Thus, both notices must be provided to potential customers. It does not make any difference if the two notices are combined on one brochure, or if they are two different brochures, so long as both notices are provided simultaneously.

One of the requirements of the first notice is that there be "an explanation of the applicability and amount of the competition transition charge." We interpret this to mean that this also include a statement or footnote to the effect that "if the customer elects to purchase electricity from another provider that the customer will continue to be liable for payment of the competition transition charge." (See Section 392(c)(2).) Inclusion of such a statement or similar language will furnish potential customers with the information necessary to be able to compare and select among service providers.

With regard to the notice describing the potential customer's right to rescind the contract, it is our interpretation of Section 394(b) that this notice should contain all of the language contained in Section 395.[41] By having the notice incorporate all of the

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[41] Section 395 provides as follows:

Footnote continued on next page

language in Section 395, residential and small commercial customers will be informed of their right to rescind the contract and the specific procedure they need to follow in order to rescind the contract. The inclusion of the language in Section 395 is consistent with the Legislature's intent to protect consumers by requiring that information be provided to consumers, and that "consumers be provided with mechanisms to protect themselves from marketing practices that are unfair or abusive." (Stats. 1996, ch. 854, Section 1(d), p. 4, and Section 10, p. 50.)

The notice provided pursuant to Section 394(b) should contain the following phrase at the end of the brochure notice, including the entity's telephone number:

> "If you have any questions regarding any of the above, please call us at ______________________ (insert the telephone number of the entity offering the electrical service)."

This will ensure that the customer has the telephone number of the entity offering the service if any questions arise.

Section 394(b) also provides that the Commission shall assist these entities in developing the notice. We believe that it would be beneficial for the industry participants themselves to propose standard notices for the staff's review. Therefore, we

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"(a) In addition to any other right to revoke an offer, residential and small commercial customers of electrical service, as defined in subdivision (h) of Section 331, have the right to cancel a contract for electric service until midnight of the third business day after the day on which the buyer signs an agreement or offer to purchase.

"(b) Cancellation occurs when the buyer gives written notice of cancellation to the seller at the address specified in the agreement or offer.

"(c) Notice of cancellation, if given by mail, is effective when deposited in the mail properly addressed with postage prepaid.

"(d) Notice of cancellation given by the buyer need not take the particular form as provided with the contract or offer to purchase and, however expressed, is

Footnote continued on next page

will allow interested parties to file with the Docket Office comments regarding the types of standard notices that the market entrants are considering. Such comments shall be filed with the Docket Office and served within 60 days from the effective date of this decision. Reply comments shall be due within 75 days from the effective date of this decision. We encourage members of the DAWG, as well as other interested parties to meet to determine if general agreement on standard notices can be reached. We shall direct the Energy Division and the Consumer Services Division to review the proposed notices, and make recommendations to the Commission as to the standardized format of the Section 394(b) notice. The Commission shall then issue a decision regarding what notice format entities offering electrical service to residential and small commercial customers shall use.

In ordering paragraph 28 of the Preferred Policy Decision, the Commission directed that "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 mechanics of who should prepare this agreement and who should retain the agreement, is a subject that should be addressed in the direct access implementation plan discussed earlier.

Electrical Corporations

Bill Format

AB 1890 specifies the bill format for investor-owned electrical corporations. Section 392(c)(1) provides that the bills of the investor-owned electrical corporations shall disclose each component of the bill as follows:

> "(A) The total charges associated with transmission and distribution, including that portion comprising the research, environmental, and low-income funds.

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effective if it indicates the intention of the buyer not to be bound by the contract."

"(B) The total charges associated with generation, including the competition transition charge.

Each investor-owned electrical corporation shall ensure that its electrical bills contain the billing components specified by Section 392(c)(1).[12]

Section 392(c)(2) requires that: "Electrical corporations shall provide conspicuous notice that if the customer elects to purchase electricity from another provider that the customer will continue to be liable for payment of the competition transition charge." Given that the Legislature's intent was to provide electricity consumers "with sufficient and reliable information to be able to compare and select among products and services provided in the electricity market," and that "consumers be provided with mechanisms to protect themselves from marketing practices that are unfair or abusive," we believe that the Section 392(c)(2) notice should be included as part of each investor-owned electrical corporation's bill to its end-use customers. (See Section 392(b).) The notice can be included as a footnote to the competition transition charge component, or somewhere else on the bill.

Affiliate Transactions

The investor-owned electrical corporations have both regulated and unregulated affiliates. These affiliates may be targeting the same customers that the investor-owned utility is currently serving, or they might be offering services which the utility does not offer to the utility's customers. In this new competitive electric market, we need to look carefully at how the UDCs interact with their affiliates.

The presence of a UDC affiliate in the same service area as the regulated UDC raises market power concerns because of their common ownership ties and the preexisting market dominance of the monopoly utility. The development of competitive markets would be undermined if the utility were able to leverage its market power into the related markets in which their affiliates compete. It is undisputed that the UDC

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[12] This bill formatting requirement is in addition to any other bill format that the unbundling proceeding may adopt.

currently has significant market power in the distribution of electricity. The Commission was concerned about this and thus separated the investor-owned utilities' control of transmission and distribution. It did so through the creation of an ISO, the PX, and the UDC. However, the concern remains that the UDC can use its market power in the distribution market to frustrate competition in the retail market. The Commission recognized this in the Preferred Policy Decision at page 71, wherein the UDC was prohibited from entering into retail contracts to purchase the output of a generation facility that is owned by it, or any of its affiliates. The Commission also addressed this concern by requiring that the utilities buy and sell all of their power through the PX.

Some of the parties have recommended that the affiliates of the UDC be barred from competing in the utility's service area. The parties who favor such a prohibition argue that unless the affiliate is barred, it is likely that the affiliated marketer will dominate the direct access market, while its affiliated UDC will serve the remainder of the market. They argue that the affiliated marketer will be able to dominate the market because of the perception of customers that the marketer is part of the UDC, or because of information that the marketer may have gotten from the UDC.

Those opposed to such a prohibition contend that precluding affiliated marketers from competing in the same service territory as its affiliated UDC will limit customer choice. They argue that such a result is completely contrary to the objective of direct access, i.e., to provide electric customers with a choice of energy services as well as providers. In addition, they assert that such a prohibition will limit competition.

Edison Source argues that this Commission lacks jurisdiction over entities that are created as unregulated companies by the regulated utilities or companies regulated by the FERC. (See D.91-02-022, 39 CPUC2d 321, 324.) We agree that an affiliated marketer of a UDC who is organized as an unregulated company cannot be prohibited from offering its services in the service territory of the UDC merely on that basis. However, as Edison Source acknowledged, the Commission can regulate the transactions between the regulated utility and the unregulated affiliated marketer. For example, Sections 314(b) and 797 give the Commission authority to inspect and audit affiliates' records.

Therefore, we prohibit the investor-owned utilities subject to our jurisdiction from forming regulated affiliates to market electricity to end-users or to engage in direct transactions as defined by AB 1890. However, we lack jurisdiction over entities created either as an unregulated company or a company that is regulated solely by the FERC, and cannot prohibit their entry into the retail electric market.

We will not prohibit affiliated marketers of a UDC, or other retailers, from competing in a UDC's service area. While such a prohibition would prevent the affiliated marketer of the UDC from leveraging the market power of the UDC to its advantage, the fact that we are not adopting a phase-in of direct access will limit to some extent the market power of the UDC. By permitting all customers the ability to choose direct access, all competitors can offer their services to these customers. Allowing full implementation makes it less likely that the affiliated marketer, together with the UDC, can dominate the market.

Such a scenario is supported by the change in position of one of the proponents of such an affiliate ban. In its opening comments to the August 30, 1996 DAWG Report, New Energy Ventures, Inc. (NEV) expressed a strong desire to impose such a prohibition on affiliated marketers. But in its reply comments to the same report, NEV recommended, that if no phase-in is required, then the utility affiliates should be allowed to participate in the utility's service territory beginning on January 1, 1998.

We note that we have opened the direct access market to all customers. Therefore, we are not as concerned that utility affiliates would be able to "crowd out" other competitors in the direct access market. If we had limited the first year of direct access to a specific number of customers, or limited the amount of megawatts eligible for direct access, we would have been concerned that the utility affiliate would gain an advantage and would lock up the available market. Such a strategy will not be as effective because we choose in this decision to allow full direct access beginning January 1, 1998. We will also require that the utility affiliate be treated the same as any other energy service provider when it comes to the handling of direct access transactions.

In adopting holding company structures for the investor-owned electrical corporations in the past, we have relied upon the corporate separation of the regulated and unregulated entities to protect against anticompetitive behavior within the new markets. The shared use of a utility's name is but one example of the need for the utilities and their unregulated affiliates to demonstrate that the operations of the affiliate is sufficiently and genuinely separate from that of the utility to prevent the use of utility resources and its attendant market advantages. Our responsibility of overseeing utility/affiliate transactions takes on added significance with the full implementation of direct access. We are concerned that the utilities' market power in their own service territories should not foreclose the entrance of electric service providers who are not affiliates of the utilities.

The Commission can impose conditions or regulations to ensure that the transactions between the affiliated marketer and the utility remain at arm's length. We will impose regulations on the transactions that can take place between the regulated entity and the affiliate offering direct transactions. The ten affiliate transaction rules that were proposed in the ALJ's proposed decision provoked reaction from the opponents and proponents of such rules. We have amended the rules in light of those competing interests. Investor-owned utilities which have affiliates offering direct access within its service territory will be required to adhere to the following affiliate transaction guidelines:

1. There shall be no shared employees, expenses or assets between these two structurally separated entities other than costs billed back by the holding company in compliance with existing affiliate transaction requirements.

2. Transactions between the regulated UDC and the unregulated affiliated provider shall be limited to the purchase of tariffed items generally available to other similarly situated electric service providers.

3. The regulated UDC shall not discriminate in the treatment of the affiliated and the non-affiliated electric service providers in the processing of direct access requests or other transactions.

4. Customer information held by the regulated UDC shall be made available to the affiliated energy service provider only with customer consent and using the same procedures for disseminating such information as is made available to unaffiliated energy service providers.

5. The affiliated entity offering electric service shall operate independently of the investor-owned utility.

6. If a customer requests information about direct access providers, the UDC shall provide a list of all energy service providers providing direct access services in its service territory, including its affiliate. The UDC shall not promote its affiliate.

7. The affiliated entity shall maintain its own books of accounts, have separate offices and utilize separate personnel, separate computer systems, and other equipment.

8. The UDC shall track the transfer of employees between the UDC and the affiliated entity.

9. The UDC shall have no transactions with an affiliated entity offering direct access transactions that also engages in FERC regulated wholesale transactions unless that entity has been authorized by the FERC to engage in wholesale transactions within the service territory of the UDC. Nothing in this rule would prohibit a UDC from engaging in transactions with an affiliate that provides only retail services and hence would not be subject to regulation by the FERC.

10. Joint marketing of electrical services shall be prohibited.

11. The UDC shall not require as a condition of any offer to, or agreement with, a customer, that the customer agree to engage an affiliated entity of the UDC or give preference to an affiliated entity's business proposal.

Each investor-owned utility shall file comments on how it intends to comply with the above affiliate transaction guidelines. In addition, we will require the utilities to demonstrate in this filing their compliance with the terms and conditions of each utility's holding company authority. This filing should contain the level of detail that is required by R.92-08-008. These comments shall be filed within 45 days from the effective date of this decision, and served on all parties to this proceeding. Reply comments may be filed by any interested party and shall be filed within 60 days from the effective date of this decision.

The above rules are modeled after the affiliate transaction rules established for the telecommunications industry regarding the affiliates of the Bell Operating Companies (BOCs) that offered cellular service in the BOCs' service territories. (See 47 CFR § 22.903) We believe that these rules have served the cellular and the local telephone industry well and allowed the unaffiliated competitors to successfully compete in the market.

In adopting the above safeguards, our objective is to let those rules govern the interaction between the utility and its affiliate so that the affiliate can operate its business with minimal government interference. We remain committed to the policy that we first articulated in R.94-04-031, the "Blue Book," that regulation should focus on those areas that remain monopolistic or where providers have significant market power. Where competition exists, or the potential for competition exists, economic regulation should be replaced with the discipline of the market place.

The fewer the transactions there are between the UDC and its affiliates, the greater the confidence we have that the affiliate lacks market power. In an ideal world the affiliate would be treated no differently by the UDC than other providers. Hence, there would be no reason for any government oversight that differs significantly from that exercised over non-affiliated providers.

In addition to the above described safeguards, the UDC shall continue to follow the reporting requirements contained in the Order Instituting Rulemaking (OIR), R.92-08-008. In that OIR, the Commission imposed annual reporting requirements for the electric, gas, and telephone utilities regarding their affiliate transactions.

A violation of these prescribed affiliate transaction rules will be interpreted by this Commission as an attempt by the regulated utility to unfairly advantage its affiliate with the intent of leveraging its market power to monopolize the emerging direct access marketplace. In order to ensure that this does not occur, we will consider inspecting the accounts, books, papers, and documents of an electrical corporation's subsidiary or affiliate regarding any transaction between the entities that might adversely affect the interests of the ratepayers of the electrical corporation. (Section 314.) We will not hesitate to use this mechanism and any other available procedures if it appears that the electrical corporation and its affiliate continue to exercise significant market power. (See Section 330(l)(3).)

We note that the FERC is addressing the issue of market power in the electrical corporations' requests for market-based pricing. How the FERC resolves these market power issues may affect how we treat the affiliates in this proceeding.

Recently, Enron Capital & Trade Resources Corporation, NEV, The School Project For Utility Rate Reduction and the Regional Energy Management Coalition, The Utility Reform Network, Utility Consumers' Action Network, and Xenergy, Inc. were allowed to file a motion in this proceeding requesting that a rulemaking be opened to develop standards of conduct between regulated electric utilities, natural gas local distribution companies, and their affiliated unregulated marketing entities. (See December 9, 1996 ALJ Ruling.) That motion was granted in D.97-04-041. A rulemaking and investigation have been opened to address those issues. (R.97-04-011, I.97-04-012.) We would envision the rules established there to replace or modify the general rules described above. However, until such time, the UDCs shall limit the transactions they have with their affiliates in the manner described above.

The August 30, 1996 DAWG Report raised the issue as to whether this Commission should require reciprocal treatment from other jurisdictions before allowing an affiliate of an electric utility that is not under the Commission's jurisdiction to offer its services within a service area that is subject to the Commission's jurisdiction. We do not believe such a requirement is useful or feasible. One of the tenets of direct access is to promote customer choice. Prohibiting new market entrants will not achieve that goal. In addition, if the utility's affiliate is located outside California, such a prohibition could run afoul of federal interstate commerce provisions. Furthermore, AB 1890 addressed this reciprocity issue in Section 9601(c) with respect to local publicly owned electric utilities, but refrained from imposing any other reciprocal conditions in other situations. This Commission should follow the lead of the Legislature and refrain from imposing any reciprocal treatment conditions as well.

The last affiliate transaction issue that we address today is the question of whether or not the investor-owned UDC, or a regulated subsidiary of such, can offer direct access transactions to consumers in its service territory by arranging on behalf of the customer to provide electrical power from outside the PX and with non-UDC owned or controlled operations. As part of our efforts to strengthen competition, it is important to ensure that the utility not exercise market power in the direct access market. The potential for exercise of such market power could exist if the UDC or a regulated subsidiary was permitted to engage in the provisioning of direct access services to new or existing customers in its service area who expressed an interest in switching from the UDC as the default provider in favor of a direct access contract.

The Preferred Policy Decision requires that the UDC sell all of its power into the PX and buy all of its power from the PX. The Preferred Policy Decision also discusses whether a utility should be allowed to engage in bilateral contracts, such as direct access. The Proposed Policy Decision reaches the conclusion that this would enable the provider with "the most concentrated market power" to enter into such contracts. The preferred policy decision states that:

> "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 though the Power Exchange." (Preferred Policy Decision, p. 72.)

We do not seek to remove this requirement in this decision. We remain committed to the Preferred Policy Decision's requirement that there be a mandatory buy/sell into and out of the PX for the utility. However, we clarify that the UDC may not provide or arrange for direct access contracts on behalf of its customers, although as indicated earlier, an unregulated affiliate may do so.

Access To Customer Information During Implementation

The Preferred Policy Decision recognized that the utilities have access to considerable information about their customers. This creates a potential marketing advantage because if a utility-affiliated electric service provider were to obtain this information, it could target and sign up preferred customers before its competitors could. (Preferred Policy Decision, pp. 71, 108.)

To neutralize that advantage, the Commission ordered that customer-specific information necessary for the distribution functions of the utility be made available to all competitors, on terms that are fair to all competitors. This is consistent with the affiliate transaction rules described above. Affiliates of the UDC should not be granted preferential treatment with respect to customer information. Any information made available to the UDC affiliate should also be made available in the same form and manner to other unaffiliated electric service providers. Before the UDC affiliate or an electric service provider can access any of this information about a particular customer, the electric service provider must obtain the customer's consent. (Preferred Policy Decision, p. 224.)

The Preferred Policy Decision left open the question of whether other electric service providers should be entitled to other types of customer information. From the seller's perspective, access to information is needed to determine whom to solicit, and how to serve customer needs before and after the sale. Competitors would like to obtain all of the following information if they could: customer names, addresses, telephone numbers, consumption data and history, appliance and equipment characteristics and uses, participation in special programs affecting use of electricity, and credit and payment histories.

In establishing the rules and mechanisms governing access to customer information, the August 30, 1996 DAWG Report provides a helpful guide for resolving issues about access to customer information issues. The report suggests that we answer the following questions:

- What kinds of customer information should be made available?
- Which parties should be eligible for access to customer information?
- What mechanism should be used to make the information equally available to all qualified parties?

- How can we prevent privileged access by some competitors?
- How much will information access cost, on which entities will those costs be imposed, and how should costs be recovered?
- How should informed customer consent to release the information be obtained?
- What rules should govern appropriate use of customer information by retailers?
- How can rules be enforced and complaints be quickly and fairly resolved?

PG&E and Edison state that basic customer information consists of the customer's name, service and billing address, telephone number if available, account number, and historical metered usage. PG&E and Edison agree that this type of information should be released to the customer or the customer's agent upon request of the customer. PG&E and Edison propose to make this information available in a standardized format. This information could be requested up to two times a year at no cost to the requesting party. The utilities, however, would seek recovery of this cost as a direct access implementation cost under Section 376. If the electric service providers are provided with a list of customers who have submitted consent forms to release the information, the utilities could provide such information in a standardized computer format at a regulated price set no higher than the fully allocated cost.

PG&E and Edison contend that although the utilities have the raw data about their customers, they do not have personalized energy use profiles for each customer in their databases. To obtain this information would entail construction of personalized profiles which PG&E and Edison assert would be expensive and time consuming to produce.

PG&E and Edison also contend that the utilities should not be required to provide data aggregation services to the electric service providers. PG&E and Edison are concerned about the costs of doing this data manipulation, as well as possible privacy or commercial sensitivity concerns. They agree that it might be appropriate to provide market participants with a data base of customer-specific usage information with the identity of the customer removed, along with associated locational and Standard Industrial Code (SIC) information. PG&E and Edison propose that the cost for such information would be determined by the Commission.

We believe the suggestions by PG&E and Edison are practical and reasonable solutions in the near term for releasing customer information. Although this type of information is very useful to new entrants, we suspect that many of the potential competitors may not have a need for this kind of information. These competitors probably already have much of this customer information in one form or the other, and know which large industrial and commercial customers they want to pursue. The large industrial and large commercial customers are also acutely aware of their energy costs. These customers can probably supply most of the information that the electric service providers are interested in.

We will require the UDCs to offer the type of information that PG&E and Edison have described. However, the consumer whose information is being sought must first provide the UDC with written authorization to release the information to either: each electric service provider, or, to all providers which seek this information. This written authorization should contain customer-specific information, such as the account number, that assures the UDC that the consumer giving the authorization is indeed the same customer whose information is being released.

We will also adopt PG&E and Edison's suggestion that this type of information can be released by the customer up to two times per year without cost to the customer. We will permit the UDCs to recover the cost of providing such information as a cost of implementing direct access.[43] However, as TURN pointed out in its comments to the ALJ's proposed decision, recovery of such costs should be limited to those costs which exceed the currently authorized revenues for similar activities.

[43] See discussion regarding "Other Direct Access Implementation Costs."

We also agree with PG&E and Edison that data manipulated profiles, or data aggregation studies, should not have to be offered by the UDCs. We will require, though, that the UDCs offer a data base containing customer-specific usage information and locational and SIC information, with the identity of the customer removed. A workshop to address the specifics of this data base, such as making the data base useful without disclosing who the customer is, the cost of providing such information, and the timing of providing such information, shall be facilitated by representatives from PG&E, Edison, and SDG&E. The workshop should consider whether other useful information such as seasonal load, and time-of-use, should be made part of this database. The workshop shall be held within 75 days from the effective date of this decision. A workshop report shall be prepared by the UDCs, and filed with the Docket Office within 100 days from the effective date of this decision. Comments to the report shall be within 115 days from the effective date of this decision.

If the metering function is unbundled at some point, the Commission will need to reevaluate its policies and rules concerning metering information. Unbundled metering opens the door to new kinds of metering services and the likelihood that the metering information can be gathered by someone other than just the UDC. Should metering be unbundled, the Commission will need to consider what safeguards and permitted uses will be allowed, and whether these metering service providers should be permitted to allow others to access this information. A useful guide toward crafting some of these rules could come from Section 2891.

Other Direct Access Implementation Costs

In the various pleadings, PG&E, SDG&E, and Edison request that the Commission identify the mechanisms for the UDCs to recover their restructuring costs. We have in another decision discussed the implementation costs associated with the joint customer education program (CEP), as well as any separate CEP that the investor-owned electrical corporations might seek to offer. We also indicated in the access to customer information section that we will permit the UDCs to recover the cost of providing the customer information.

The utilities have also expressed the desire to establish other memorandum accounts as well to track other costs they believe are being incurred to accommodate the implementation of direct access. In our cost recovery plan decision, D.96-12-077, we addressed the earlier requests by the utilities to establish a subaccount under the Industry Restructuring Memorandum Account (IRMA) to track the costs of implementing direct access. When that decision was voted upon, we regarded those requests as premature. At that time we had not yet addressed the policy issues surrounding direct access that might be critical in determining the types of costs that should be included in such a subaccount. (D.96-12-077, p. 23.) In this decision we have decided many of the missing policy parameters. However, the utilities have not yet provided us with a comprehensive scope of costs that they propose to include as direct access implementation costs. As pointed out by PG&E and Edison in their joint comments to the August 30, 1996 DAWG Report, these activities would include but may not be limited to the following:

- Consumer education/protection efforts and customer information costs
- UDC Systems development, implementation, and testing for new capabilities required to interface with the ISO, Power Exchange and others.
- installation and reading of real-time pricing meters
- UDC billing system modifications required to interface with the ISO, Power Exchange and others.

The above categories of activities are too broad to distinguish which of them specifically can be attributed to the implementation of direct access. We recognize, however, that it is important that the utilities timely expend the appropriate amounts to ensure that direct access, and other restructuring activities, are implemented quickly and smoothly. In order to accomplish that, we will authorize the investor-owned electrical corporations to immediately establish an interim, 90-day memorandum account to track all of the costs for the categories identified above, as well as for the costs which exceed the currently authorized revenues of processing customer information requests.

At the same time, we direct the utilities to file within 21 days of the effective date of this decision advice letters to establish appropriate IRMA subaccounts, into which all of the costs in the interim memorandum account will be reallocated, and future costs tracked. The utilities should seek to establish the following memorandum subaccounts:

- direct access implementation costs
- ISO/PX and other wholesale market interface costs
- Hourly-interval meter installation and reading costs
- UDC Billing system modification costs
- Customer information release systems costs

We direct the investor-owned electrical corporations to serve their advice letters on all parties to this proceeding. Pursuant to GO 96-A, interested parties will have 20 days within which to protest those advice letters should they choose to do so. The advice letters of the utilities should include proposed tariff language regarding the subaccounts, and they should provide clear and sufficient criteria to demonstrate how the utilities intend to allocate the costs of such activities to each subaccount category. In addition, the advice letters should clearly provide for the recording of offsetting revenues where appropriate. Once the Commission has approved the form of the IRMA subaccounts, the utilities may begin transferring the amounts tracked in the interim memorandum account into the appropriate IRMA subaccount, and to track all future costs associated with those subaccounts.

The establishment of the interim memorandum account and the IRMA subaccounts only permit the investor-owned electrical corporations with the opportunity to seek recovery of the recorded costs at a later date. The establishment of such accounts do not guarantee the recovery of those costs. The transition cost proceeding shall establish the procedures to examine whether these tracked costs should be recovered, the reasonableness of these costs, and if deemed appropriate, the recovery of such costs.

Findings of Fact

1. The Preferred Policy Decision adopted a framework for competition in which customers have the right to choose their supplier of electricity.

2. The Preferred Policy Decision transformed California's electricity systems from a bundled electric service system to a set of segmented functions including generation, transmission, and distribution.

3. The ISO is responsible for operating the transmission system.

4. The purpose of the PX is to develop a spot market for electricity.

5. Direct access allows direct and indirect sales of electric services to retail, end-use customers.

6. The UDC will provide nondiscriminatory distribution services to all customers within its service territory, and will continue to procure power for those customers who do not want to arrange their own retail contracts with non-utility suppliers.

7. The Roadmap Decision called for the formation and recognition of various working groups to aid in the resolution of the many implementation concerns.

8. The DAWG was recognized in the Coordinating Commissioner's letter of June 21, 1996.

9. The August 30, 1996 DAWG Report contains a compendium of ideas from the DAWG members on the various consumer choice issues.

10. On November 26, 1996, the FERC issued an order which conditionally approved the ISO and the PX.

11. A JACR was issued on December 9, 1996, which directed PG&E, SDG&E, and Edison to meet with interested participants concerning the coordination of the communications and data systems needed for the ISO, PX, UDC, SCs, and direct access providers, and to discuss whether these systems would result in any technical limitation on allowing direct access for all customers.

12. AB 1890 was signed into law on September 23, 1996.

13. AB 1890 declared that it is the Legislature's intent to protect the consumer by requiring registration of certain sellers, marketers, and aggregators of electricity service,

requiring information to be provided to consumers, and providing for the compilation and investigation of complaints.

14. CellNet served copies of its opening comments to the August 30, 1996 DAWG Report, but did not file them with the Docket Office.

15. The Preferred Policy Decision envisioned that direct access would only apply to the service territories of PG&E, SDG&E and Edison.

16. The Preferred Policy Decision did not address how customers in the service territories of other Commission regulated electrical corporations would be treated.

17. The Commission's electric industry restructuring initiative is based on the creation of a competitive marketplace for electric energy and its derivative products and services.

18. The Commission must guard against any abuse of market power in the emerging direct access market, as well as in the PX.

19. Direct access involves the provisioning of electric service to retail customers.

20. A retailer is any electric service provider that enters into a direct transaction with an end use customer.

21. Although the Preferred Policy Decision adopted a phase-in schedule for direct access, it also solicited comment on whether a phase-in schedule was even necessary, and whether eligibility could be opened to all electricity consumers before the five year period or even after the twelve month initial phase.

22. In D.97-02-021, the Commission stated that the phase-in schedule set forth in the Preferred Policy Decision was no longer appropriate, or even necessary.

23. Section 365 provides in part that any phase-in of customer eligibility for direct transactions shall be equitable to all customer classes, and accomplished as soon as practicable, consistent with operational and other technological considerations.

24. An extensive record in this rulemaking and investigation has focused on whether there are any operational and other technological constraints to direct access.

25. The January 17, 1997 Report concluded that there are no technical limitations to direct access based on the ISO systems as presently designed or on the UDC systems as the utilities anticipate they will be adopted.

26. The January 17, 1997 Report contained a letter from the ISO Trustee which stated that the limitation of the number of SCs is not, in and of itself, a limit on the number of direct access customers that can be accommodated.

27. Technical constraints are technology-based limitations which impede or harm the reliable operation of the electrical system.

28. The January 17, 1997 Report stated that no matter what the Commission's decision on phase-in is, there will be no impact on the physical reliability of electricity service.

29. Operational constraints are those things which affect the operation of a system, such that the element or integration of elements would impact the physical reliability and integrity of the electrical system.

30. The role of the SCs will reduce the transactions processing burden on the ISO because the SCs will aggregate the various direct access transactions prior to submitting the schedules to the ISO.

31. Since the ISO does not require a minimum load for the schedules to be submitted by the SCs, there is no reason to limit direct access only to those whose aggregated load totals 8 MW.

32. There are no operational and other technological considerations which requires us to limit a consumer's ability to elect direct access.

33. Providing all customer classes with the choice of direct access on day one will stimulate the competitive forces and provide the competition necessary to drive down California's electricity prices.

34. Availability of direct access for all consumers does not mean that every customer who desires direct access will have it immediately.

35. The direct access implementation plans allow the Commission to closely monitor developments regarding the processing of direct access requests and to intervene if necessary.

36. Direct access affects the type of metering that customers need to have in place.

37. For direct access to work in conjunction with the ISO, the market requires the ability to account for consumption on a periodic, hourly basis.

38. There are approximately 10 million metering locations in California.

39. Of the industrial meters, approximately 50% are capable of supporting the data requirements for direct access, i.e., hourly recording of energy usage, and of the commercial meters, about 10% are capable of supporting the data requirements for direct access.

40. Installation of hourly interval meters for all 10 million electricity customers in California would require a multi-year effort.

41. Consideration as to whether load profiles should be developed for certain customers whose maximum demand is equal to or greater than 20 kW, but less than 50 kW should be addressed in the load profiling workshop.

42. Customers whose accounts have a maximum demand of less than 20 kW may choose to install an hourly meter to take advantage of direct access.

43. The hourly PX rate option, also referred to as virtual direct access, allows customers to purchase electricity that is reflective of their usage in real time or time-of-use increments based on the PX price.

44. The Preferred Policy Decision ordered the utilities to offer the hourly PX rate option by January 1, 1998, and recognized that the availability of the hourly PX pricing option is dependent on the type of meters that are in place.

45. The Preferred Policy Decision adopted a five year plan for installing the necessary meters for customers other than those in the categories of Domestic, GS-1, and TC-1.

46. Requiring hourly interval meters to participate in direct access or the hourly PX rate option is likely to accelerate the meter installation schedule, or eliminate the need to impose a meter installation schedule altogether.

47. Metering standards are necessary to ensure that the customer's meter is capable of interfacing with the meter reading equipment of the UDC, or if such service is unbundled, with the equipment of another meter reading provider, as well as to ensure the efficiency, reliability, compatibility, and safety of the metering systems.

48. A statistical load profile is an estimate of customers' hourly consumption over a given period of time.

49. The use of statistical load profiles to estimate the hourly consumption of small accounts will facilitate the aggregation of small accounts and small customers, and will enable retail providers to accommodate those customers who have standard monthly meters.

50. The use of load profiling will enhance the opportunities for customers to participate in the direct access market.

51. Access to aggregation may be the only feasible way in which small customers can participate in, and benefit from, direct access.

52. Aggregation allows a customer with multiple locations to aggregate all of their own loads.

53. Aggregation can reduce the transaction costs of direct access, and may allow customers to increase their market leverage by aggregating their demand.

54. Section 366 specifically permits the aggregation of customer load.

55. The term aggregator is defined in Section 331(a).

56. AB 1890 does not address the method by which large commercial and industrial customers can initiate a change in provider.

57. Section 366(d) and (e) describes the procedures that must be followed before the electricity provider for a small commercial or residential customer can be changed.

58. The UDC will provide distribution services to all customers regardless of their choice of electricity supplier, and will be required to supply electricity to those customers who choose to remain with their existing electric utility.

59. During the four year transition period, the three largest UDCs must bid all their generation into the PX, and purchase power from the PX on behalf of the utility's customers.

60. As the distribution entity, the UDC shall be responsible for service connection and disconnection.

61. Customers who choose the direct access option, as well as customers who do not choose direct access, have the obligation to pay the transition costs provided for in Sections 367, 368, 375, and 376.

62. An understanding of the protocols necessary to support the settlement process between the scheduling coordinators, the UDCs, the electric service providers, and end-use customers can be facilitated by developing the RIMP.

63. Section 394(a) requires that the Commission establish a registration system for each entity offering electrical service to residential and small commercial customers within the service territory of an electrical corporation.

64. The term small commercial customer is defined in Section 331(h) as a customer that has a maximum peak demand of less than 20 kW.

65. There is no requirement in AB 1890 that those entities offering electrical service to large commercial and industrial customers need to register with the Commission.

66. There is no requirement in AB 1890 that those electric service providers offering electrical service in the service territories of the publicly owned electric utility need to register with the Commission.

67. Section 394(b) refers to two different notice requirements, the first is that there be a notice of the price, terms, and conditions of the service, as well as an explanation of the applicability and amount of the competition transition charge, and second, that there be a notice describing the potential customer's right to rescind the contract.

68. Section 392(c)(2) requires that electrical corporations shall provide conspicuous notice that if the customer elects to purchase electricity from another provider that the customer will continue to be liable for payment of the competition transition charge.

69. Ordering paragraph 28 of the Preferred Policy Decision directed that each direct access customer shall sign an agreement to pay their share of the transition costs and thereby waive any jurisdictional objection they might otherwise raise in any forum.

70. In this new competitive electric market, the Commission needs to look carefully at how the UDCs interact with their affiliates.

71. The presence of a UDC affiliate in the same service area as the regulated UDC raises market power concerns because of their common ownership and the preexisting market dominance of the monopoly utility.

72. Allowing full implementation of direct access makes it less likely that the affiliated marketer can dominate the market, together with the UDC.

73. The Commission has processes and procedures to monitor and regulate affiliate transactions of the UDC.

74. The Preferred Policy Decision left open the question of whether other electric service providers should be entitled to customer information.

75. In D.96-12-077, the Commission addressed the earlier requests by the investor-owned electrical corporations to establish a subaccount under the IRMA to track the costs of implementing direct access.

Conclusions of Law

1. AB 1890 directs the Commission to authorize direct transactions between electricity suppliers and end use customers, and that such transactions are to commence simultaneously with the start of the ISO and PX, which is to occur as soon as practicable but no later than January 1, 1998.

2. The motion to intervene of Payless should be granted.

3. Should CellNet decide to file its opening comments to the August 30, 1996 DAWG Report, the Docket Office should accept the late filing.

4. The motion of CLECA and CMA for leave to file their reply comments to the August 30, 1996 DAWG Report one day late should be granted.

5. Cinergy's motion to supplement its October 15, 1996 reply comments to the August 30, 1996 DAWG Report should be granted.

6. Since AB 1890 does not appear to limit the legislation's applicability to the state's three largest electrical corporations, the rules adopted in this decision should apply to all investor-owned electrical corporations.

7. Market power concerns will need to be addressed in our own proceedings, as well as at the FERC.

8. To address market power concerns in both the PX and the emerging direct access markets, the direct access option must be a fully developed and viable option.

9. The availability of direct access may limit the exercise of market power in the PX.

10. For direct access to be a real alternative, it must be widely available, accessible, and convenient.

11. In the absence of any showing of operational or other technical constraints, no phase-in is required.

12. The 8 MW limitation contained in the Preferred Policy Decision is inconsistent with Section 366(a) because it arbitrarily limits how and with whom customers can aggregate.

13. Direct access should be made available to all California electricity consumers on January 1, 1998, regardless of customer class or size of load.

14. In order to reasonably manage the implementation of direct access, the investor-owned electrical corporations should be required to file a direct access implementation plan for the Commission's review and action.

15. The investor-owned electrical corporations should convene a meeting with interested parties to develop the direct access implementation plans.

16. In implementing full direct access, the Section 365(b)(2) preference should be preserved, and requests from such customers should go to the front of any queue in processing direct access requests.

17. The standards and procedures set forth in this decision regarding the processing of the direct access transaction requests should be adopted.

18. In the event that the restructured electricity environment cannot handle the volume of direct access transactions, or if the success of the marketplace is threatened in the first 12 months of operation, the ISO governing board, with the approval of the Oversight Board, should have the ability to declare an emergency, and notify the Commission that an emergency exists.

19. In the event the ISO declares an emergency, no contingency plan limiting a customer's participation in direct access will be implemented without this Commission's express approval.

20. In the event a contingency plan is needed, such a plan should preserve the preference under Section 365(b)(2).

21. Other market participants should be allowed to petition the Commission to implement a TEMP should the need arise.

22. Universal metering is a direct access constraint only if there is no reasonable, available substitute for hourly interval meters.

23. As a condition precedent to allowing a customer to participate in a direct access transaction, a customer whose account has a maximum demand equal to or greater than 20 kW shall have in place a meter which provides, at a minimum, hourly metering.

24. Customers with accounts that have a maximum demand of less than 20 kW may participate in direct access through use of statistical load profiles, or they can choose to pay for the cost and installation of a meter which can provide hourly metering.

25. The development of the tariff for the hourly PX rate option shall occur in the consolidated ratesetting proceeding.

26. The metering installation schedule that we outlined in the Preferred Policy Decision should be suspended because the issue of whether metering should be unbundled is unresolved, and because the non-load profile customers who want to participate in direct access or avail themselves of the hourly PX rate option will be required to install hourly interval meters.

27. Those customers who want to avail themselves of the hourly PX rate option will be required to install hourly interval meters.

28. Since Section 378 prevents us from requiring all customers to shift to an hourly rate, the meter installation schedule of the Preferred Policy Decision would force a customer who decides to stay on the UDC flat rate option to pay for a meter that the customer does not need.

29. The Energy Division should ensure that a workshop with the UDCs and other interested parties is held within 45 days of the effective date of this decision to address metering standards.

30. The Energy Division should ensure that a workshop is held with the UDCs and other interested parties, including members of the DAWG, and the Ratesetting/Unbundling Working Group, to develop statistical load profile methodologies.

31. A ruling may be issued before the workshop on load profiling to help narrow the focus of the workshop, and to possibly request written comments on certain topics.

32. All customers interested in participating in direct access may aggregate or combine their own loads individually, and may aggregate or combine their load with other customers through an aggregator.

33. All customers and retail providers should be allowed to aggregate their loads in whatever fashion they can arrange, so long as the settlement procedures are capable of accurately calculating who is responsible for what.

34. The methods and procedures for large commercial and industrial customers to initiate a change of provider shall be addressed in the direct access implementation plan.

35. The verification required under Section 366(d)(1) shall follow the procedures set forth in subdivisions (e)(1), (e)(2), and (e)(3) of Section 366.

36. We do not intend to require registration of the independent third-party verification companies, or to get involved in who should have to pay these companies.

37. The service providers need to ensure that the third-party verification companies meet the criteria in Section 366(e)(1), and that the companies maintain the paperwork necessary to confirm that a customer did indeed verify a change of provider.

38. Should problems arise over whether a residential or small commercial customer was switched by another company without the customer's consent, we intend to focus our inquiry on whether the new electric service provider properly followed the provisions of Section 366.

39. The Commission will continue to regulate the rates, terms, and conditions of the distribution and electric services provided by the UDC, including their ability, if any, to engage in competitive market services and transactions in the post-transition era.

40. It shall be presumed that a customer who does not initiate the process needed to change providers will, by default, be provided with power by the UDC.

41. In accordance with Section 370, to the extent the customer does not use the electrical corporation's facilities for direct access, the electricity marketer must advise the customer to confirm in writing that the customer is obligated to pay the transition costs.

42. The UDC shall be obligated to serve any customer who no longer engages in direct access so long as adequate notice is provided to the UDC, and the customer pays for the electric service.

43. The Energy Division should ensure that a workshop with the UDCs and other interested parties is held within 60 days of the effective date of this decision to address retail settlement and information flow issues.

44. Market rules regarding non-utility electric service providers are authorized under AB 1890 to ensure that consumers are protected.

45. The UDC is exempt from the registration procedures set forth in Section 394.

46. Any retailer offering electric service to small commercial or residential customers is required to register with the Commission.

47. D.97-02-021 recognizes that AB 1890 has given the Commission jurisdiction over aggregators, brokers, and marketers for purposes of consumer protection.

48. The Legislature only intended that those entities offering end-use customers the commodity of electrical energy be required to register, and that energy efficiency and load management services are not required to register.

49. The Commission has the authority to impose additional reasonable conditions related to registration beyond the minimum requirements listed in Section 394(a) because the Legislature has stated an intent to protect consumers.

50. Imposition of the additional registration requirements are outweighed by the public interest, and will help to ensure the provider's accountability in the event the provider fails to perform.

51. The registration requirement adopted in this decision shall terminate on January 1, 2002, unless extended by a later enacted statute.

52. The Commission may revoke the registration number of the registrant if the registrant fails to abide by any of the market rules or consumer protection rules adopted in this proceeding, or if the registrant violates any other statutory provisions governing its conduct.

53. The Commission may bring civil or criminal actions against the registrant or non-registrant pursuant to Sections 2101, 2111, and 2112.

54. Each entity who is registered pursuant to Section 394 shall, at the time of offering the electrical service, provide the notices described in Section 394(b).

55. We interpret the Section 394(b) requirement to mean that a statement should be included to the effect that if the customer elects to purchase electricity from another provider, that the customer will continue to be liable for payment of the competition transition charge.

56. We interpret the Section 394(b) requirement that there be a notice describing the potential customer's right to rescind the contract to mean that this notice should contain all of the language contained in Section 395.

57. The notice provided pursuant to Section 394(b) shall also contain the following phrase at the end of the brochure notice: "If you have any questions regarding any of the above, please call us at ________________________ (insert the telephone number of the entity offering the electrical service)."

58. Interested parties should file comments regarding the types of standard notices that they believe market entrants should use.

59. The mechanics of who should prepare the agreement to pay the direct access customer's share of the transition costs and waiver of any jurisdictional objection is a subject that should be addressed in the direct access implementation plan.

60. Each investor-owned electrical corporation shall ensure that its electrical bills contain the billing components specified by Section 392(c)(1).

61. The Section 392(c)(2) notice shall be included as part of each investor-owned electrical corporation's bill to its end-use customers as a footnote to the competition transition charge component, or somewhere else on the bill.

62. Since the Commission lacks jurisdiction over entities that are created as unregulated companies by the regulated companies or companies regulated by the FERC, the Commission cannot prohibit an affiliated marketer of a UDC, which is organized as an unregulated company, from offering its services in the service territory of the UDC merely on that basis.

63. The Commission has the power to regulate the transactions between the regulated utility and the unregulated affiliated marketer to ensure that the transactions remain at arm's length.

64. We will not prohibit affiliated marketers from competing in their affiliated UDC's service area.

65. The investor-owned utilities shall be required to adhere to the affiliate transaction guidelines when dealing with their affiliates.

66. Each investor-owned utility shall file comments on how it intends to comply with the affiliate transaction guidelines.

67. The Commission should refrain from requiring reciprocal treatment from other jurisdictions before allowing an affiliate of an electric utility that is not under the Commission's jurisdiction from entering into a service area that is subject to the Commission's jurisdiction.

68. Upon written authorization by the customer, every UDC shall be required to offer electric service providers the basic customer information consisting of the customer's name, service and billing address, telephone number if available, account number, and historical metered usage.

69. The UDCs shall be permitted to recover the cost of providing basic customer information as a cost of implementing direct access to the extent such costs exceed the currently authorized revenues for similar activities.

70. The UDCs shall be required to provide electric service providers, at a cost to be determined, a data base containing customer-specific usage information and locational and SIC information, with any customer-specific identifying information removed.

71. Should metering be unbundled, the Commission will need to reevaluate its policies and rules concerning the collection, use, and dissemination of metering information.

72. The investor-owned electrical corporations should be permitted to establish memorandum accounts to track their expenditures related to the costs of processing requests for customer information.

73. The investor-owned electrical corporations should be authorized to establish an interim, 90-day memorandum account to track the expenditures incurred for the activities discussed in this order, and to file advice letters to establish the appropriate IRMA subaccounts into which the amounts in the interim memorandum account shall be transferred upon approval of the advice letters.

SECOND INTERIM ORDER

IT IS ORDERED that:

1. The September 25, 1996 motion to intervene filed by Payless ShoeSource, Inc. is granted.

2. Should CellNet Data Systems, Inc. (CellNet) desire to file its opening comments to the August 30, 1996 Direct Access Working Group (DAWG) Report, CellNet shall be permitted to late file its comments with the Docket Office. Any such filing shall comply with the applicable filing rules provided for in Article 2 of the Commission's Rules of Practice and Procedure. If the filing is in compliance with the Commission's rules, CellNet's opening comments shall be filed as of the date the document is tendered for filing.

3. The October 16, 1996 motion filed by the California Large Energy Consumers Association and the California Manufacturers Association for leave to file their reply comments to the August 30, 1996 DAWG Report one day late is granted. The Docket Office is directed to file their reply comments that were attached to the motion as of October 16, 1996.

4. The November 19, 1996 motion of Cinergy Services, Inc. (Cinergy) to supplement its reply comments to the August 30, 1996 DAWG Report is granted. The supplemental comments contained in the body of Cinergy's November 19, 1996 motion shall be treated as though it was a part of Cinergy's October 15, 1996 reply comments.

5. The following rules are adopted, and shall apply to all investor-owned electrical corporations:

   a. Direct access should be made available to all California electricity consumers on January 1, 1998, regardless of customer class or size of load.

b. In order to participate in a direct access transaction, those customers with a maximum demand equal to or greater than 20 kilowatts (kW) shall have in place a meter which provides, at a minimum, hourly usage measurement. The customer shall be responsible for the cost of the meter and the cost of meter installation. Those customers with a load of less than 20 kW may participate in direct access through load profiling, or they can choose to have an hourly interval meter purchased and installed at their own cost. We shall also consider whether circumstances warrant that load profiles be developed for some customers whose loads are equal to or greater than 20 kW, but less than 50 kW.

c. In order to participate in the hourly power exchange (PX) rate option, customers are required to have an hourly interval meter.

d. All customers interested in participating in direct access transactions shall be permitted to aggregate or combine their load with other customers through an aggregator by providing the aggregator with a positive written declaration of such intent.

e. The standards and procedures set forth in this decision governing the processing of the direct access transaction requests are adopted, and shall be followed by all the utility distribution companies (UDCs).

(1) In order to reasonably manage the implementation of direct access, the investor-owned electrical corporations, as the UDCs, shall be required to file a direct access implementation plan for the Commission's review and action. The direct access implementation plan shall include the pro forma tariffs for the terms and conditions of direct access.

(a) A process to address the issues associated with the pro forma tariffs will be established in an assigned Commissioners' ruling or in an Administrative Law Judge's (ALJ) ruling.

(2) In formulating their direct access implementation plans, the UDCs shall work with interested parties by convening a meeting within 30 days from the effective date of this decision.

(3) The direct access implementation plans shall be filed on or before July 1, 1997 with the Docket Office, and served on all parties to this proceeding. Comments on the plan shall be filed and served on or before July 18, 1997.

(4) Each UDC shall begin accepting direct access requests on November 1, 1997, which shall become effective on or after January 1, 1998.

(5) Beginning November 15, 1997, the UDCs shall submit to the Director of the Energy Division and to other interested parties a report containing the information described in this decision regarding the previous month's direct access implementation activities. This reporting requirement shall terminate with the report ending for the month of June 30, 1999.

(a) Parties interested in receiving such reports should contact the UDCs directly.

f. In the event the restructured electric environment cannot handle the volume of direct access transactions, or if the success of the marketplace is threatened in the first 12 months of operation, the independent system operator (ISO) may declare an "emergency".

(1) In the event of such a declaration, the ISO should notify the Commission that an emergency exists, and recommend what actions the Commission can take to assist the ISO and other participants in alleviating the emergency.

(2) If the ISO declares an emergency, the UDCs, if requested by the ISO, shall institute a 10 day moratorium on processing requests for direct access. This moratorium can be extended by a ruling of the President of the Commission or his designee.

(3) Upon the declaration of an emergency by the ISO, the Energy Division shall ensure that a workshop is held within five days from such a declaration, in conjunction with the UDCs, the ISO, and all other interested parties to discuss and develop a contingency plan. A

workshop report shall be prepared by the UDCs, in conjunction with the other workshop participants, and filed with the Docket Office no later than five days after the workshop.

(4) The Executive Director, subject to later ratification by the Commission, may implement any emergency contingency plan.

g. Other market participants may petition the Commission to implement a transition emergency mitigation plan if the volume of direct access requests cannot be handled.

h. The UDC shall provide nondiscriminatory distribution services on equivalent terms and conditions to all customers in its service territory regardless of their choice of electricity supplier, and furthermore, shall be required to supply electricity to those customers who choose to remain with their existing electric utility.

(1) During the four year transition period, the three largest UDCs must bid all their generation into the PX, and purchase power on behalf of the utility's customers from the PX.

(2) As the distribution entity, the UDC shall be responsible for service connection and disconnection until such time the Commission may otherwise decide.

(3) The Commission will continue to regulate the rates, terms, and conditions of the distribution and electric services provided by the UDCs, including their ability, if any, to engage in competitive market services and transactions in the post-transition era.

(4) It shall be presumed that a customer who does not initiate the process needed to change providers will, by default, be provided with power by the UDC.

(5) The UDC shall be obligated to serve any customer who no longer engages in direct access so long as adequate notice is provided to the UDC, and the customer pays for the electricity.

i. Any retailer offering electric service to small commercial or residential customers is required to register with the Commission by completing and forwarding a registration form identical to the one attached hereto as Appendix B, a copy of which shall be made available by the Commission upon request and which shall also be made available on the Commission's Internet Web site, verifying the form in accordance with the text of this decision, and paying the $100 registration fee.

(1) Each registrant shall be obligated to inform the Commission in writing within 30 days of any changes to the registration form.

(2) Registration forms will be accepted by the Commission's Energy Division beginning July 1, 1997.

(3) Upon registration, the Energy Division shall issue a registration number to each registrant.

(4) This registration requirement shall terminate on January 1, 2002 unless it is extended by a later enacted statute.

(5) The Executive Director shall take all necessary steps to ensure that the Commission staff has the necessary support mechanisms in place by July 1, 1997, to undertake this registration procedure.

(6) Each entity who is registered pursuant to Public Utilities (PU) Code Section 394 shall, at the time of offering the electrical service, provide the notices described in PU Code Section 394(b), and in this decision, and shall abide by whatever consumer protection rules the Commission may adopt in the future.

j. Each investor-owned electrical corporation shall ensure that its electrical bills contain the billing components specified by PU Code Section 392(c)(1), and the PU Code Section 392(c)(2) notice as described in the text of this decision.

k. In accordance with PU Code Section 370, to the extent the customer does not use the electrical corporation's facilities for direct access, the electricity marketer must advise the customer to confirm in writing that the customer is obligated to pay the transition costs.

l. Upon written authorization by a customer, every UDC shall be required to disclose to the designated electric service provider the customer's basic customer information. Access to this type of information shall be provided up to two times per year free of charge to the customer or the recipient of such information.

(1) The UDCs shall be required to offer to all electric service providers a data base containing customer-specific usage information and locational and Standard Industrial Code information, with the customer's identity removed.

m. The eleven affiliate transaction guidelines listed in this decision shall be adhered to by the investor-owned electrical corporations in any transactions with their affiliates.

6. The metering installation schedule called for in the Preferred Policy Decision is suspended until further notice.

7. The Energy Division shall ensure that the following workshops are held:

a. A workshop shall be held with the UDCs and other interested parties to address the technical specifications for metering and metering communication standards.

(1) This workshop shall be held within 45 days of the effective date of this decision. A workshop report shall be jointly prepared by the UDCs in conjunction with the other workshop participants, and filed with the Commission's Docket Office within 70 days of the decision's effective date. The workshop report shall be served only on those participants attending the workshop, on the assigned Commissioners and ALJ, and anyone else requesting a copy before the workshop report is filed. A copy of the workshop report, together with a computer diskette of the workshop report, shall be served on the Energy Division. Comments to this report shall be filed within 85 days of the decision's effective date.

b. A workshop shall be held with the UDCs and other interested parties to develop statistical load profile methodologies.

(1) This workshop shall be held within 30 days of the effective date of this decision. A workshop report shall be jointly prepared by the UDCs in conjunction with the other workshop participants, and filed with the Docket Office within 40 days of the effective date of this decision, and served as described in Ordering Paragraph 7.a. Comments to this report shall be filed within 55 days of the decision's effective date.

(2) If evidentiary hearings are needed for load profiling issues, these hearings will tentatively take place during the week of July 21, 1997 or July 28, 1997, and prepared testimony shall be due sometime during the week of June 30, 1997, and reply testimony during the week of July 14, 1997.

c. A workshop shall be held with the UDCs and other interested parties to address the settlement and information flow issues. This workshop shall be held within 60 days of the effective date of this decision. A workshop report shall be jointly prepared by the UDCs in conjunction with the other workshop participants, and filed with the Docket Office within 80 days of the decision's effective date, and served as described in Ordering Paragraph 7.a. Comments to this report shall be filed within 95 days of the decision's effective date.

d. A workshop shall be held with the UDCs and with other interested parties within 75 days from the effective date of this decision to address the specifics of the customer information data base, the cost of providing such information, and the timing for providing such information. A workshop report shall be jointly prepared by the UDCs in conjunction with the other workshop participants. The workshop report shall be filed with the Docket Office within 100 days from the effective date of this decision, and served as described in Ordering Paragraph 7.a. Comments to this report shall be filed within 115 days from the effective date of this decision.

e. The Energy Division staff shall have the discretion to combine each of the workshops ordered above with any of the other workshops to facilitate the resolution of common issues. If the workshops are combined, the Energy Division staff shall notify the assigned Commissioners and ALJ and recommend a schedule for the filing of the combined workshop reports and comments.

8. The investor-owned electrical corporations are authorized immediately to establish an interim, 90-day memorandum account to track the costs incurred for the activities pointed out by Edison and PG&E in the August 30, 1996 DAWG Report and summarized in this decision. The investor-owned electrical corporations shall file advice letters within 21 days from the effective date of this decision to establish this interim memorandum account.

9. Within 21 days from the effective date of this decision, the investor-owned electrical corporations shall file advice letters to establish the subaccounts described in this decision under the Industry Restructuring Memorandum Account (IRMA). Upon approval of these advice letters, all of the amounts recorded in the interim memorandum account described in the ordering paragraph above will be transferred into the appropriate subaccounts, and such subaccounts shall track all future costs associated with such subaccounts until terminated by the Commission. The subaccount advice letters shall contain proposed tariff language and shall clearly specify the criteria for allocating the kinds of activities to each appropriate IRMA subaccount.

10. Each investor-owned electrical corporation shall file comments on how it intends to comply with the affiliate transaction guidelines adopted in this decision. These comments shall be filed with the Docket Office within 45 days from the effective date of this decision, and served on all parties to this proceeding. Reply comments may be filed by any interested party and shall be filed within 60 days from the effective date of this decision.

11. The assigned Commissioners or the ALJ, acting on their behalf, may issue rulings to amend the schedule as necessary to accomplish the objectives set forth in the ordering paragraphs above.

This order is effective today.

Dated May 6, 1997, at San Francisco, California.

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

I will file a concurring opinion.

/s/ P. GREGORY CONLON
President

Appendix A

Parties Filing Opening and/or Reply Comments To The 8/30/96 DAWG Report

1. California City-County Street Light Association
2. California Department of General Services; University of California; California State University
3. California Energy Commission
4. California Farm Bureau Federation
5. California Industrial Users
6. California Large Energy Consumers Association; California Manufacturers Association[44]
7. California Mobilehome Resource and Action Association
8. California Retailers Association
9. CellNet Data Systems, Inc.[45]
10. Center For Energy Efficiency and Renewable Technologies
11. Cinergy Services, Inc.
12. Coalition of California Utility Employees
13. County of Los Angeles
14. Direct Access Now: California Retailers Association; School Project for Utility Rate Reduction/Regional Energy Management Coalition; California League of Food Processors; California City-County Street Light Association; Robinsons-May Department Stores; PayLess ShoeSource, Inc.; San Diego Gas & Electric Company; Enron Capital & Trade Resources; and U.S. Department of Defense
15. Edison Source
16. Electric Clearinghouse, Inc.
17. Energy Producers and Users Coalition
18. Enova Energy Inc.
19. Enron Capital & Trade Resources
20. Federated Department Stores: Macy's West; Bloomingdales
21. Greenlining Institute; Latino Issues Forum
22. Itron, Inc.
23. Los Angeles Department of Water and Power
24. Lucent Technology
25. Metropolitan Water District of Southern California
26. New Energy Ventures, Inc.
27. Office of Ratepayer Advocates
28. Office of Ratepayer Advocates; Eastern Pacific; Utility Partnership Solutions
29. Pacific Gas & Electric Company

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[44] See decision text for resolution of the motion of CLECA/CMA for leave to late file their reply comments to the August 30, 1996 DAWG Report.

[45] See decision text for resolution of Cellnet's opening comments to the 8/30/96 DAWG Report.

30. Pacific Gas & Electric Company; Southern California Edison Company
31. PayLess ShoeSource, Inc.
32. San Diego Gas & Electric Company
33. School Project for Utility Rate Reduction; Regional Energy Management Coalition
34. SESCO, Inc.; Residential Energy Services Companies' United Effort
35. Southern California Gas Company
36. Southern California Edison Company
37. Utility Consumers' Action Network
38. Utility Systems Corporation
39. Vantus Energy Corporation; Vantus Power Services
40. Western Mobilehome Parkowners Association
41. Western Mobilehome Parkowners Association; California Mobilehome Resources and Action Association
42. Working Assets Green Power, Inc.

REGISTRATION APPLICATION FOR NON-UTILITY SERVICE PROVIDERS

ESP No. ______
Date Granted ______

PLEASE PRINT OR TYPE

1. Exact Legal Name of Registrant: ______

   Doing Business As (DBA): ______

2. Current Address:

   ______
   Street Address

   ______
   City State Zip Code

3. Current Telephone Number: ______

4. Type of Ownership:

   ______ Individual ______ Partnership ______ Corporation
   ______ Limited Liability Company

5. a. If registrant is a corporation, the state in which the registrant is incorporated:
   ______ (State of Incorporation)

   b. List names and titles of corporate officers. (Attach additional page if necessary):

   ______
   ______
   ______

6. a. If a sole proprietorship or partnership, the county in which the fictitious business name statement has been filed, if applicable.

   ______(Name of County)

   b. If a partnership list all general partners. (Attach additional page if necessary.)

   ______
   ______
   ______

Complete and mail this form along with $100.00 check or money order to:
State of California
Public Utilities Commission
Energy Division - ESP Registration
505 Van Ness Avenue
San Francisco, CA 94102-3298

INCOMPLETE APPLICATIONS CANNOT BE PROCESSED

FOR CPUC USE ONLY

Application Processed by: ______

Date: ______

7. If a limited liability company list all managers and/or officers and their titles. (Attach additional page if necessary.)

____

____

____

8. The address and telephone number of the registrant's principal place of business if different from current address telephone number listed in line numbers 2 and 3:

Street Address

City State Zip Code

Telephone Number

9. The name, title, address and telephone number of the person to whom correspondence or communication regarding customer complaints are to be addressed:

Name Title

Street Address

City State Zip Code

Telephone Number FAX Number (If Available) E-Mail Address (If Available)

10. Are you a certified renewable resource provider pursuant to Public Utilities Code Section 383?

_____Yes ________________Certification Number _____No

11. Name and Address of Agent for Service of Process:
(Must Be Located In California)

Name:________________________________

Street Address:____________________________

City and State:____________________ Zip Code:________

12. Criminal Record Clearance: Has the registrant or any of the general partners or corporate officers or limited liability company managers or officers ever been convicted of any felony?

_____No _____Yes If yes, please explain on a separate page.

DECLARATION

I, (print name and title) ____________________________ declare under the penalty of perjury that the above statements are true and correct.

Dated this ________ (day) day of) ________ (month) 19___ (year) at ________________ (place of execution)

Signature:________________________________

Glossary

AB 1890: Assembly Bill 1890 which was signed into law on September 23, 1996 as Chapter 854 of the Statutes of 1996. AB 1890 provides the legislative guidance for restructuring of the electric industry in California.

Aggregator: any marketer, broker, public agency, city, county, or special district, that combines the loads of multiple end-use customers in facilitating the sale and purchase of electric energy, transmission, and other services on behalf of these customers.

Broker: an entity that arranges the sale and purchase of electric energy, transmission, and other services between buyers and sellers, but does not take title to any of the power sold.

CEP: the customer education program.

Competitive Transition Charge (CTC): a nonbypassable charge on each customer of the distribution utility, including those who are served under contracts with nonutility suppliers, for recovery of the utility's transition costs.

Consumers: the end-users of electricity, who may be served either by the utility distribution company or by a non-utility, retail electric service provider.

Customer Education Program (CEP): the educational effort required under Public Utilities Code Section 392, which requires electric corporations, in conjunction with the CPUC, to devise and implement an education program that informs customers of the changes to the electric industry.

Direct Access Transaction: a contract between any one or more electrical generators, marketers, or brokers of electric power and one or more retail customers providing for the purchase and sale of electric power or any ancillary services.

Electric Service Provider: an entity which provides electric service to a retail or end-use customer, but which does not fall within the definition of an electrical corporation under Section 218.

Generators: those entities which will design, construct, own, operate, and maintain generation assets to supply energy and ancillary services to the competitive market.

Independent System Operator (ISO): The ISO is responsible for the operation and control of the statewide transmission grid.

Marketer: any entity that buys electric energy, transmission, and other services from traditional utilities and other suppliers, and then resells those services at wholesale or to an end-use customer.

Power Exchange (PX): the entity that will establish a competitive spot market for electric power through day and hour ahead auction of generation and demand bids.

Public Goods Charge (PGC): a nonbypassable surcharge imposed on all retail sales to fund public goods research, development and demonstration, and energy efficiency activities, and possibly to support low income assistance programs.

Retailers: an electric service provider who enters into a direct access transaction with an end-use customer, i.e., aggregators, brokers, and marketers.

Scheduling Coordinators (SCs): entities certified by the Federal Energy Regulatory Commission that act as a go-between with the ISO on behalf of generators, supply aggregators (wholesale marketers), retailers, and customers to schedule the distribution of electricity.

Supply Aggregators: also known as wholesale marketers. These entities act on behalf of generators to arrange and implement commercial transactions in the competitive generation supply market.

Small Commercial Customer: a customer that has a maximum peak demand of less than 20 kilowatts.

Virtual direct access: also known as the hourly PX rate option. This rate option allows customers to purchase electricity on a rate schedule that reflects their usage in real time or time of use increments based on the PX price.

Utility Distribution Companies (UDCs): the entities which will continue to provide regulated services for the distribution of electricity to customers and serve customers who do not choose direct access.

R94-04-031/I94-04-032
D97-05-040
Commissioner P. Gregory Conlon concurring:

This decision begins the important process of implementing our direct access program to bring the benefits of customer choice and competition to California's retail electricity consumers. Those benefits are too well known at this point to bear repeating. Their importance underscores the need to bring direct access to as many customers and as speedily as possible.

At the same time, we must be careful not to proceed too hastily. I have been concerned from the beginning that we not set up expectations for the customer that we cannot deliver on. As the proposed decision makes very clear, direct access for all customers does not necessarily mean there could not be delays in the first year in switching customers to direct access. The challenge is to manage carefully the transition so that we have a clear definition of the number of orders to switch that can be accommodated, and so that customers understand when they will be able to switch.

The Implementation Plans this decision directs the utilities to submit to us are the crucial first step in ensuring that the transition is managed carefully. Among other things, they will provide us with a critical piece of information that has been sorely lacking up to now, namely, the number of direct access requests the utilities are capable of processing each month. Based on that data, and the comments of parties, we will set standards for the processing of direct access requests. We will then monitor carefully the utilities' success in performing to those standards.

We will adopt the final implementation plans for processing direct access transactions this Fall. If there clearly are problems with expectations and availability, we will have to address them then. Even then, we will still be operating without the other critical element in the equation—how many customers are likely to *demand* direct access in the first year. At this point we have no way of knowing whether that number is going to be 50,000 or 500,000. In the context of that remaining--but important--uncertainty, we will face a formidable challenge in fashioning a direct access program that can live up to the expectations it creates.

This decision expands the requirements for hourly metering by lowering the maximum demand threshold above which direct access customers must have hourly meters from 50kW to 20kW, a change I heartily support. The decision to allow customers below that threshold to participate in direct access through load profiling possibly is a transition solution, and we will take up later whether a better longer-term policy is to require all direct access customers to have hourly consumption meters. As the decision notes, hourly metering can facilitate direct access transactions by providing data that result in more accurate settlements. It remains to be seen whether statistical load profiling will provide sufficient accuracy for that purpose.

Finally, I note that this decision suspends the mandatory metering requirements of the Preferred Policy Decision for utility customers above 100 kW maximum demand. Hourly meters provide the crucial consumption data that customers need to reshape their load profiles in order to lower their bills. When added together, these individual actions will shift demand away from peak periods, lowering the cost of electricity and providing environmental benefits. We will have to revisit whether these compelling benefits suggest we need to reinstate a utility meter installation schedule.

/s/ P. Gregory Conlon

P. Gregory Conlon, President

R94-04-031/I94-04-032
D97-05-040
Commissioner P. Gregory Conlon concurring:

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P. Gregory Conlon by JLS

P. Gregory Conlon, President