DESIGN AND IMPLEMENTATION OF DIRECT ACCESS PROGRAMS

A Report of the Direct Access Working Group

In Response to the
California Public Utilities Commission
Decision 96-03-022

August 30, 1996

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EXECUTIVE SUMMARY

ES-1. Process Followed by the Direct Access Working Group

The origins of the Direct Access Working Group ("DAWG") lie in the CPUC's Policy Decision on electric industry restructuring (D.95-12-063, as modified by D.96-01-09 ("Policy Decision")). There the CPUC announced that a pre-existing Working Group which addressed restructuring issues would "be integral to the roadmap" to be adopted. (Policy Decision, p. 182.)

The CPUC issued the referenced "roadmap" on March 13, 1996 (D.96-03-022 ("Roadmap")). The Roadmap called for the formation and CPUC recognition of a number of "working groups", consisting of interested stakeholders, to assist the CPUC in conducting the transition to the new market envisioned in the Policy Decision. These working groups were to address issues within major groupings established in the Roadmap. (Roadmap, at pp. 7-12.) One such grouping encompassed issues related to consumer choice, which included direct access, consumer safeguards, and public purpose programs. (*Id.* at p. 20.) This grouping of issues led to formation of DAWG.

On April 4, 1996, Commissioners Knight and Neeper, who had been assigned separately oversight of consumer choice and public purpose issues, released a Joint Assigned Commissioners' Ruling, which scheduled a Scoping Workshop for April 22, 1996, to discuss these issues, timelines, interaction with the CPUC, and related matters. (JACR of 4/4/96, at p. 2.) The JACR also requested interested stakeholders to submit statements of issues related to consumer choice and public purpose programs in preparation for the Scoping Workshop. (*Id.*, at pp. 7-9.)

Even before attending the Scoping Workshop, numerous stakeholders gathered in San Francisco on April 17 to begin organizing DAWG. This organizational meeting resulted in the adoption of a mission statement and structuring of DAWG into technical teams to be overseen by a coordinating committee. Four technical teams were established:

Team A	Implementation
Team B	Market Rules
Team C	Metering and Communications Systems
Team D	Consumer Education and Protection

The eventual composition of the coordinating committee and all four technical teams reflected the eligibility of all stakeholders to participate in their work. In total over 200 individuals representing a large number and variety of stakeholders contributed to the DAWG process.

(Attached in Appendix A is a list of all entities who participated in at least one meeting of DAWG or any of the four technical committees.)

On April 22, 1996, stakeholders met for the Scoping Workshop and addressed the issues announced in the JACR of April 4. This was followed on April 30 and May 1 by the first meetings of the DAWG technical committees, who further organized issues within their purview. A meeting of all DAWG members able to attend thereafter occurred in Los Angeles on May 7, 1996. At that meeting, technical committee chairs volunteered and were approved. Like the composition of the teams themselves, the chairs reflected various stakeholder interests:

Team A	Randy Britt, Robinsons-May Dan Carroll, California Industrial Users
Team B	Carolyn Kehrein, California Manufacturers Association and Enron Capital & Trade Resources Malcolm McCay, San Diego Gas & Electric
Team C	Nancy Gault, Southern California Edison
Team D	Lynn Maack, Division of Ratepayer Advocates Michael Shames, Utility Consumers Action Network

The group also approved a tentative schedule for further DAWG team activities. This aggressive schedule established both team and full DAWG meetings weekly or bi-weekly from mid-May through the end of August to be held throughout the state in order to increase the opportunity for geographically diverse stakeholders to attend at least some if not all meetings. (Appendix C contains the schedule of DAWG and technical team meetings.) DAWG and its technical teams also tried to post all meeting agendas, locations, and minutes on the DAWG web site maintained by DRA.

The critical work of DAWG then commenced in earnest, as the scheduled technical team and full DAWG meetings progressed over the next two and a half months. Each technical team discussed and debated substantive issues within its charge. Minutes of each meeting were taken and distributed. Outside speakers with information specific to team activities attended some team meetings. For example, Team C sponsored attendance at the National Meter Reading Conference in Sacramento in June, after which meter vendors from throughout the metering industry conducted a metering workshop open to all interested stakeholders. DAWG participants circulated drafts of and comments on position papers via fax, e-mail, and the WorldWide Web, after which further discussion and debate frequently followed.

Each technical team made significant efforts to reach consensus on key issues. Where consensus eluded stakeholders (which was often the case), the teams resolved to present alternatives in the final report with "Pros"and "Cons" for each alternative. After a full DAWG meeting in early

June, the coordinating committee also suggested that all positions in this report be presented without attribution, a suggestion which DAWG adopted.

As this work progressed, Assigned Commissioners Knight and Neeper provided further guidance and support in several ways. Commissioner Neeper attended meetings in San Diego and Los Angeles. The Assigned Commissioners issued another Joint Assigned Commissioners' Ruling on May 17, 1996. This JACR expanded on and clarified a number of issues, including the expectation that this report would be filed by the Direct Access Working Group, with the result that the investor owned utilities were not required to file separate direct access proposals. (JACR of 5/17, at p. 8.) The JACR also stated the intent to hold a "checkpoint" meeting to ensure that DAWG would meet the first report due date. (*Id.*) At that meeting, held on July 9 in the CPUC Auditorium in San Francisco, the chairs of each technical team reported on the progress of their teams and responded to questions and entertained suggestions from those in attendance. Commissioners Knight and Neeper also provided further guidance to DAWG during the checkpoint meeting.

After weeks of meetings, discussion, debate, and drafting, the full DAWG met in Burbank on August 1, 1996. Participants in that meeting selected an editorial team by consensus and adopted principles to guide that team's efforts. Drafting team leaders had brought chapters for which they were responsible to the meeting. During the meeting the chapters were assembled and copied, and copies of the resulting initial draft of this report were distributed at the end of meeting, with copies being sent by overnight delivery to those on the DAWG master list who did not attend the meeting. DRA also posted the draft on the DAWG WorldWide Web site.

The editorial team consisted of the following persons, and again reflected the diversity of the stakeholders who participated in DAWG from April through August:

Randy Britt	Robinsons-May
Michael Jaske	California Energy Commission
David Kaplan	PG&E
Lorenzo Kristov	California Energy Commission
Anthony Mazy	Division of Ratepayer Advocates
Malcolm McCay	SDG&E
Megan Scott-Kakures	Southern California Edison

The editorial team's initial charge was to organize, clarify, and fine-tune the initial report draft and generate a new draft by August 19, after receiving and taking account of comments from stakeholders, which were due to the editorial team by August 12. After distribution of the second draft, the editorial team held a meeting on August 23, where stakeholders had an opportunity to make final comments. The editorial team then completed this report.

ES-2. Major Elements of Direct Access Programs, Phase-In and Eligibility to Participate

ES-2.1 Introduction

ES-2.1.1 Market Participants

There will be a number of players, each filling a different role, in the restructured marketplace. Chapter 3 summarizes the roles to be played and tasks to be undertaken by each.

The Independent System Operator (ISO) will be responsible for ensuring reliable operation of the power grid, controlling dispatch of electricity through the grid from generators ultimately to customers.

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

The Utility Distribution Companies (UDCs) will succeed the current investor owned utilities, continuing to provide regulated services for the distribution of electricity to customers. As regulated entities, the UDCs will still be subject to CPUC oversight.

Scheduling Coordinators (SCs) will be certified entities that act as a "go-between" with the ISO on behalf of generators, supply aggregators (wholesale marketers), retailers, and customers to schedule distribution of electricity.

Supply aggregators (wholesale marketers) will act on behalf of generators to arrange and implement commercial transactions in the competitive generation supply market.

Retailers will act as agents for buyers of power in procuring generation supply and related energy services.

Generators will design, construct, own, operate, and maintain generation assets to supply energy and ancillary services to the competitive market. Owners of such assets will include not only the current IOUs but in all likelihood existing and future generators of power both in and outside California.

Consumers are the end-users of electricity, and may be served either by UDCs as default purchasers of bundled service, or by the competitive market as direct access customers.

Readers interested in the technical interaction of market participants in the new marketplace should read all of Chapter 3, much of which is quite technical and defies ready summary.

ES-2.1.2 Key Steps for Development and Implementation

The DAWG process identified the following key steps for development and implementation of a direct access program:

2 Market transformation requirements;
2 Program design and regulatory approvals;
2 Consumer education;
2 Consumer decision to exercise choice;
2 System verification prior to commencement; and
2 Program operation and monitoring.

These steps are discussed in broad outline in subsequent sections of this summary and in Chapter 1 of the Report.

ES-2.2 Achieving Meaningful Customer Choice

Direct access is one of the first aspects of electricity allowing customer choice. Chapter 2 proposes certain principles to ensure that the opportunity to exercise choice is meaningful for all customer classes. These principles suggest meeting the following customer needs:

- Ready access to affordable accurate multi-lingual information about electricity providers so customers can compare price, quality, service record, and terms of service.

- Ability to aggregate load efficiently on a non-discriminatory basis, and to have barriers to competition removed.

- Rules to require fair dealing, including penalties for market abuses, unresponsiveness, and discrimination, and provisions for similarity of rates throughout the state.

- Mechanisms to redress complaints. (See further discussion at Section ES-5.3.)

- Ability to participate in regulatory oversight of the restructured industry.

- Ability to control release of personal information and freedom from intrusive marketing. (See further discussion at Section ES-3.2.)

- Safe service with access to differentiated levels of service without imposing service limiters on low-income customers.

- Enforcement of a code of conduct on service providers.

- Access to savings from direct access for all customers regardless of the number of options they may have.

- A market which avoids unnecessary transaction costs, has low barriers to entry, and provides equitable sharing of restructuring costs.

- Continuing support of social and environmental policies, including "lifeline" rates and safeguards for customers who are low-income, elderly, or disabled.

At this general level most parties can support these principles, but debate over their detailed interpretation and implementation provoked major disagreements. Some further development can be expected as DAWG continues its efforts on consumer education and protection and provides another report to the CPUC on these subjects.

ES-2.3 Phase-In and Eligibility Requirements

Many DAWG participants viewed phase-in (if any) of direct access and eligibility to participate as among the most if not the most critical matters within DAWG's charge. These subjects are at the heart of restructuring, since it is generally believed that direct access will provide the competition necessary to drive California's electricity prices lower for all consumers.

Here, as in many areas, the DAWG Implementation Team (Team A) did not reach consensus. As a review of the report will disclose, however, extensive, detailed, and substantive discussion and debate transpired, both in meetings and in circulated written position papers and comments. Chapter 4 contains the product of that effort.

The debate concerning phase-in and eligibility requirements encompasses six principal issues.

ES-2.3.1 Is Phase-In Necessary?

The first and perhaps most vigorously debated issue is whether phase-in is necessary at all. Proponents of universal availability of direct access on January 1, 1998 emphasize successful pilots in other states and nations and a belief that oversubscription in all customer classes may well not occur. These advocates also question whether concerns about technical barriers raised by phase-in proponents are overstated, pointing out that many larger industrial and commercial customers already possess necessary metering equipment and contending that participation of other customers may be transitioned through load profiling.

Those advancing the necessity of a transition period note that the Policy Decision specifically calls for a minimum one year phase-in, and indeed contemplates that it may take as long as five

years to transition to the new market. They also reject the minimization of technical issues, noting that the question of universal metering is only one of the technical hurdles to be overcome. Others include development, testing, and implementation of the ISO's interim command and control system and other computer communications systems, and the need for a "shakedown" period for these systems; current limitations on the computing power needed to settle ISO imbalance costs; and the volume of information which may be processed by the utilities' billing systems, especially in the presence of contemplated complete unbundling of billing information.

ES-2.3.2 How Long a Phase-In?

Analysis of the remaining issues assumes, as it must to proceed, that some transitional period will occur. Assuming a phase-in, the natural next question is how long it will be. Some proposed only a year, while others suggested multi-year periods from three to five years. Several proposed that a mid-course evaluation should occur at some point during the phase-in to determine whether further phasing was necessary and if so, how much longer it would continue.

ES-2.3.3 What is the "Gatekeeper"?

The third overall issue concerns the identity of the gatekeeper (or "descriptor") on each stage of phase-in. Some stakeholders disagree with the megawatt-based stepping of eligibility announced in the Policy Decision. They observe that most phase-in rationales have in common the difficulties in dealing with numbers of customers. These participants urge that the true bottleneck for eligibility is therefore the number of transactions that the utilities can process and suggest adoption of a transaction-based gatekeeper. Others agree with the Policy Decision, indicating the only issue to be decided in this regard is what those megawatt limitations describe: peak demand of participating customers or energy consumption of participating customers. Still others suggest that these two approaches need not be mutually exclusive, recommending that the ultimate determination of the gatekeeper(s) be delayed until overall customer characteristics concerning geographic distribution, energy consumption, and billing are better known.

ES-2.3.4 Who Is Eligible?

The fourth issue, which pertains to customer eligibility for each step of the phase-in period, is to a certain extent necessarily conjoined with the gatekeeper discussion, since the identity of the gatekeeper will affect customer eligibility. This issue also poses many subissues.

One subissue again springs from the Policy Decision, which not only staged phase-in by megawatt availability but also by customer size. The Memorandum of Understanding that preceded the Policy Decision posed a minimum megawatt limit for a single customer to meet in order to bilaterally contract, and a maximum limit on the megawatts that could be provided through customer aggregation. Each of these limits would change over time. However, a number of parties urged that there be no such size constraints during any transition period, noting that this alternative does not artificially limit the number who may participate in direct access and

that some of the transaction processing concerns have been alleviated with the creation of the ISO's scheduling coordinator concept.

A second subissue emanates from the Policy Decision's mandate that all customer classes have an opportunity to participate in each stage of phase-in. Not surprisingly, given the interest of many DAWG contributors in either selling or buying direct power as soon as possible, this area generated many alternatives. They include suggestions for proportional representation, triggered by percentage of the number of customers in the class, percentage of load, or percentage of those expressing interest in direct access; retention of the megawatt-based limitations on each phase, with an exclusion of residential customers from eligibility for the available megawatts but with inclusion of residential customers via load profiling; determination of participation each year as a matter of policy by the CPUC; organization of phase-in by industry or business type in order to take account of competitive industry parity concerns; and elimination of customer class participation rules in favor of reliance on customer education to divine those in each class who are interested.

Another customer eligibility subissue addresses the procedures to follow in the presence of either over- or under-subscription to direct access during any level of phase-in. Concluding that undersubscription should lead immediately to universal eligibility would be hasty, according to some stakeholders. They express concerns that such undersubscription may be the product of incomplete or ineffective customer education, leading to the specter of universal eligibility resulting in sudden oversubscription if new education finds the "hot button" issue for potential direct access consumers. This concern leads to a number of potential responses to undersubscription besides immediate universal eligibility.

Several solutions also surfaced to deal with oversubscription. One suggested that any customer with the required equipment and contractual arrangements be allowed to participate immediately upon implementation. Use of a lottery within oversubscribed customer classes was suggested, as was simply allowing participation on a first-come, first-served basis. A blended alternative of these two would allow first-come, first-served to be the initial test, using a lottery as a tie breaker. The final proposal would allow everyone who subscribes to participate, ratcheting the load served downward in proportion to the number or load of participants in the class.

The final customer eligibility subissue addresses whether customers who have been picked once to participate in direct access may lose their place in later stages. This subissue arises because some suggest that there should be a revisitation of eligibility at some or all stages of the transition, to give those not already selected a greater chance of being selected for the next phase. In such a circumstance, customers then participating might not be selected for the next phase. Two alternatives are posed: once selected, always selected, or re-selection before each stage.

ES-2.3.5 Education and Solicitation

The fifth issue concerns customer education and solicitation for each step of the transition period. Various alternatives concerning who will be responsible for education were proposed in DAWG deliberations: the CPUC, the utilities (both now and after they become UDCs), market participants, or the Consumer Education Trust. Participants also suggested a number of alternatives concerning the conduct of customer solicitations for participation during the phase-in. The differences in approach in this area concerned whether utilities or others would solicit customer interest before marketer contacts with potential customers, and whether non-utility energy suppliers would obtain customer data for use in their marketing activities before initiating contact. (This issue is discussed further in this summary at Section E.2 below.)

ES-2.3.6 Changes in Service

A final phase-in issue is whether and how direct access customers can change energy suppliers. DAWG participants seem to agree that unlimited changes should be allowed with appropriate notice to the supplier and the UDC. The length of notice to commence direct access or change providers varies depending upon any need to change or install metering equipment and the type of equipment installed, which affects when the meter can be read before the service change is effective. This option provides maximum customer flexibility, but it could lead to service issues if customers switch faster than UDC systems can react or there are information exchange problems between the UDC and energy supplier.

A subissue in connection with potential limitations on service changes during phase-in concerns imposing a requirement that a customer who returns to bundled UDC service from direct access remain with the UDC for a set time period. One alternative solution would require an agreement upon return to remain a bundled UDC customer for a year. The other requires only waiting until the next period of open season enrollment, if any.

ES-3. Market Rules

ES-3.1 Rules for Market Participants

ES-3.1.1 General Summary of Issues

DAWG participants debated what, if any, rules should be instituted to govern the behavior of players in the new marketplace. Three sets of activities which may require specific market rules surfaced: system operations (technical needs to ensure safety, reliability and management of system-wide effects); fair competition (to prevent market power abuse, minimize barriers to entry and facilitate sustainable, efficient competition); and consumer protection (fair dealing and protection of privacy.)

The parties differed over which of these categories of rules should apply to which types of market participants. Contributors seemed to agree that rules to ensure system operations should

apply to all those whose actions may affect the electric system. Parties did not agree, however, on the extent to which private, competitive firms should be subject to industry-specific rules dealing with competitive behavior or contracts with customers, with views ranging from proponents of a laissez faire approach to those arguing for broad application of market rules to ensure fair competition. There were also proposals for rules governing relations between competitive firms and regulated monopolies to ensure a level playing field with no special advantages available to monopoly affiliates.

ES-3.1.2 Enforcement of Rules

Three different mechanisms were suggested to govern participation of retail service providers in the new marketplace. The first would require either governmental registration or industry certification of retail energy service providers. The second calls for governmental licensing of providers, which would require more of them than mere registration. The third alternative mandates bonding of providers or institution of some other requirement to demonstrate the provider's financial soundness.

A second enforcement issue is how the rules will be enforced. Private or public civil enforcement through the courts might apply to some grievances, while others might be handled through the CPUC or new enforcement organs to be established by industry participants.

ES-3.1.3 Scheduling Coordinator Requirements

It is expected that scheduling coordinators will require certification or licensing before they may submit schedules to the ISO, although who will grant such certification (the ISO, FERC, or the CPUC) is not yet known. To be certified, scheduling coordinators must ensure that they can meet their financial obligations and possess the technical capabilities to perform their expected functions.

Parties did not agree whether certification is expected for transactions between scheduling coordinators and other market participants. One proposal is that no such certification should be required. A second view would require some level of state regulation of these transactions.

ES-3.1.4 UDC Requirements

UDCs will have a new set of obligations in the new marketplace. DAWG did not reach consensus on the identity or scope of those obligations.

One issue concerns the obligation to connect and serve. The differences in two offered alternatives generally surround obligations of market players other than the UDC. Under both alternatives, the UDC’s obligations to customers are similar. They include connection of customers to and delivery of energy from providers over the distribution system, accepting the return to bundled service of direct access customers, and serving as the default provider for

customers not served by competing energy suppliers. The UDC has limited obligations to direct access customers.

The first alternative differs from the second in also addressing others in the marketplace. The UDC would be required to connect generators to and allow nondiscriminatory wheeling of energy over the transmission or distribution system, to provide competitors with customer-specific data with customer consent, and to bill competitors for their use of the distribution system.

The UDC will also be required to provide a system load forecast to the PX, and will retain the right and obligation to ensure the safety and security of the distribution system.

Two other issues in this area concern the UDC role as custodian of customer information and the question of billing for energy provider services. Issues in this area are summarized later in this summary at sections ES-3.2 and ES-4.2 respectively.

ES-3.1.5 Competitive Electric Service Provider Requirements

DAWG technical team D, which discussed issues related to consumer protection and education, will file a further and more detailed report on October 30, 1996. Some issues concerning requirements for competitive electric service providers ("ESPs") have been discussed, however, and are summarized here.

One area of discussion encompassed potential certification requirements for ESPs. One alternative proposes only minimal certification requirements. Those opposing such limited oversight point out that the unregulated telecommunication industry still requires regulatory oversight, and express concerns that smaller customers are unsophisticated in procuring electrical services. These parties advance a more stringent proposal calling for regulatory oversight of ESPs. This alternative would require that ESPs who interact with retail customers be registered, licensed, and bonded by the CPUC, to ensure ESP accountability and customer recourse for ESP failure to perform. It also would require ESPs to adopt and adhere to a minimum code of conduct, an example of which is appended to this report at Appendix D.5.

Debate also ensued concerning permissible retail territories for unregulated utility affiliates. One proposal would allow such affiliates to compete within their parent utility's service areas, pointing out this adds to the competitive mix. Opponents fear that such affiliate competition within the service area would tilt the playing field in favor of the incumbent monopoly utility by allowing opportunities for parent-subsidiary cross-subsidization. The competing alternative is to allow unregulated affiliates to compete only outside the parent utility's service area. Proponents see little potential for market abuse under this scenario. Opponents fear that incumbent monopoly market power would affect fair competition even outside the parent's service area and propose that affiliate competition be allowed only after the new competitive market is well established.

A final area of discussion addressed in the report concerns reciprocity for utilities and affiliates who conduct business outside CPUC jurisdiction. Only one proposal surfaced. It would require those outside CPUC jurisdiction who wish to compete for customers within current IOU service territories to allow current IOUs and affiliates to compete for their customers. Potential extra-jurisdictional competitors who did not agree to such reciprocity would be denied the opportunity to compete in the retail marketplace, although they could still do business in the wholesale market or with the PX. Parties supporting this option contend that a true competitive market requires competition not only within but also outside California and that requiring reciprocity furthers that goal. Those opposing this alternative express concerns over the CPUC's legal authority to require such reciprocity and that it would limit the supply of competitive electricity available to California consumers.

ES-3.1.6 Issues Concerning Franchise Fees and User Surcharges

Concerns surfaced during the DAWG process that electric restructuring could negatively impact the financial stability of local governments. A major concern is ability to identify payments due to local governments given future unbundling of bills. It is suggested that the CPUC protect full revenue collection by local governments. Specifically, some participants assert all energy providers must be required to remit franchise fees and utility user taxes, including not only current utilities but also future UDCs, energy service providers, and independent power producers. However, other parties urge that restructuring should not create new revenue generation opportunities for local governments that would allow collection of more revenue than at present, noting such a development could deter the ultimate goal of lower electricity cost.

ES-3.1.7 Master Metering Issues

Privately-owned distribution systems that are not public utilities currently serve some California electricity consumers. Power is delivered to a master meter, from which it is distributed. Although such private systems exist for mobilehome parks, apartment complexes, shopping centers, industrial parks, and military bases, DAWG discussion focused on mobilehome parks.

The intersection of direct access and private distribution systems poses a number of complexities. Such distribution facilities are located on private property without public utility easements, leading to questions of who will read meters and maintain the system. Landlord-tenant law may constrain service termination for non-payment of electricity bills. Billing would be even more complex than it already may be under direct access. Extra park-owner costs may arise in order to provide direct access to park residents, costs which may not be recoverable under current CPUC precedent.

ES-3.2 Access to Customer Information During Implementation

Access to customer information necessary to allow a level playing field during the transition to competition poses many issues. The following material summarizes issues which are vital to fair opportunity to compete for customer business, especially during any phase-in.

ES-3.2.1 Why is Information Needed?

Put simply, a competitive marketplace requires and thrives on information, including information about potential customers. From the seller's perspective, information is necessary not only to determine whom to solicit, but also to address how to serve customer needs both before and after the sale. Information that would prove useful to all competitors in the new electric marketplace includes customer names, addresses, telephone numbers, raw consumption data and history as well as analyses of this information, appliance and equipment characteristics and uses, record of participation in special programs affecting usage of electricity, and credit and payment histories. While all this information may be useful, however, it may not be automatically available for reasons discussed below.

ES-3.2.2 Who Should be Allowed to Obtain and Use Information?

Recognizing the major marketing advantage the incumbent monopoly utilities could reap from customer information in their possession, the Policy Decision required that customer specific information necessary for utility distribution functions be made available on fair terms to all competitors in the generation sector. The identity of those competitors is not further explicated, leading to debate concerning who is entitled to claim a right to receive what information. Although there was no debate over whether retailers having access to such information must be qualified to act as such, there was disagreement over whether all qualified retailers should receive all information. Some stakeholders asserted precisely that position. Others argued that generation retailers and energy service retailers using public goods charge funding to promote energy efficiency should receive different information.

A related question concerns information access by unregulated affiliates of the present incumbent utilities. Some DAWG participants maintain that UDC provision of equal access to all energy retailers is a sufficient rule of fair access to prevent abuses by affiliates. Others, however, urge that these affiliates should be immediately limited from access to and use of such information, to prevent their gaining an early marketing advantage. They further contend that affiliates in the future should be able to obtain and use no more information than non-affiliate competitors. They finally urge the CPUC to expeditiously order the utilities to file statements of their policies and practices with respect to affiliate access to customer information.

ES-3.2.3 Which Information Can be Made Available?

This issue transfers the focus of the discourse from the utility and its potential competitors to customers. Among the issues is whether customer consent is required for release of all or only certain information, which necessarily includes discussion of who owns the data.

Categorization of customer information is useful before examining positions advanced concerning its use. Customer information is segregable into four general categories: information linked to a specific individual, some of which may be more sensitive than other such information (personal); information that cannot be linked to a distinct individual or group (non-personal); statistics describing a unique individual (individual descriptors); and statistics describing a group of individuals (aggregate descriptors).

Strong divisions exists concerning information ownership, since ownership may imply complete right to control. One position holds that information currently possessed by utilities was gathered by them as a necessary business expense, and therefore that it is proprietary to the utility. Another position states that information gathering was paid for by ratepayers and that the need to gather the information implies a fiduciary relationship with respect to the customer and the information, which ultimately the customer owns.

This division remains regardless of the category of information involved. As to personal information, some claim that the customer owns it, with the right to control its dissemination and receive value for its sale. These parties point out that unlike other industries, utilities have obtained such information as part of their regulated monopoly positions and at times only after being ordered to do so through government intervention. Others assert that personal customer information is owned by utilities. They explain that shareholders have borne the risk if expenses such as information gathering exceed authorized revenues. Some parties on both sides of this debate also point out that ownership issues need not be resolved for the CPUC to adopt reasonable public interest requirements concerning use of personal information.

A composite (but not consensus) position also surfaced. This position concludes that personal, customer-specific information (raw data) does belong to the customer, but any information which has been aggregated, compiled, or manipulated by a utility is proprietary to the utility.

The remaining issue concerns customer consent to release of information. This issue includes discussion of whether consent will not be required for release of certain information, and the mechanism used to obtain consent.

Parties seemed to agree that non-personal customer information, which by definition is not identifiable to an individual and therefore poses no risk of invasion of privacy or proprietary rights, should be releasable without customer consent. However, they parted ways over whether non-sensitive personal information (which by definition creates little potential for harm to the individual if released) may be released without customer consent.

There was agreement that consent should be required for release of sensitive personal information. Disagreements revolved around the manner of obtaining such consent. Some stakeholders would require that customers directly consent to information release by "opting in" upon being requested to consent. They point out that clear and direct consent should be shown

to release such information, and such consent can only be assured through an opt-in program. Others argued that assuming that customers consent if they do not refuse to do so upon notification ("opting out") is sufficient protection. Those advancing this position point out that unlisted telephone numbers may be the most sensitive information and that opting-out adequately protects such information. They also noted that more customer data would likely be available under an opt-out regime.

A related issue concerns the role of utilities in administering information access. Some participants believed that utilities should merely be encouraged to administer access programs, while others urged a requirement for such participation.

ES-3.2.4 How Should Information be Distributed?

Numerous options surfaced concerning the manner of dissemination of customer information. An initial issue is whether data will be released one time before implementation or on a continuing basis. No strong positions for or against either position were established.

The options for manner of distribution include using an electronic bulletin board; releasing information in a standard form on computer disk; using an escrow holder called an "energy service fulfillment house"; or developing a combination approach depending on the category of information being released.

ES-3.2.5 What if Anything Must be Paid for the Information?

The Policy Decision also does not define what terms would be fair for provision of information to competitors, leading naturally to a debate over what could be charged for such information. Cost-based proposals would require provision of information at either the incremental cost of its production or no higher than fully allocated cost. Some stakeholders note a difference between information which consists of raw data such as customer-specific usage history and information which has been manipulated or compiled by the utility. As to the latter information, they assert that if such information is provided at all, it should be at a fee chosen by the utility.

Debate also ensued over the use of proceeds from the sale of data. Some asserted that the revenue should be returned to customers. Others proposed that it be retained by the utility, subject to net revenue sharing under performance based ratemaking.

ES-4. Technical and Organizational Challenges

The CPUC requested that DAWG address technical hurdles that must be overcome to implement its restructuring vision. The two principal areas of technical challenge that emerged are billing, and metering and communications. As elsewhere, participants advanced numerous opinions and consensus was elusive.

ES-4.1 Metering and Communications

The metering and communication system is vital to the restructured marketplace. Information that originates with end use and must flow to various market participants is critical to market success. Many issues arose in discussions about this system.

ES-4.1.1 Scope of Metering System Changes

Metering system changes must occur under direct access, because many more transactions must be recorded hourly for price signal and billing purposes. Such changes are required for both physical and virtual direct access customers, and under the Policy decision would apply to all customer classes. The issue here, ultimately for CPUC determination, is whether universal real time metering will be required. The report suggests the CPUC consider its policy approach to metering in light of the need to balance the benefits of competition with maximizing customer choice.

ES-4.1.2 Evaluating and Summarizing Technology Options

Many meters currently installed in California will not support direct access as defined in the policy decision. Twenty to fifty percent of industrial meters, ten percent of commercial, and fewer than ten percent of residential have such capability. Analysis of technology options and their applicability to current customer groups therefore is required.

Industrial customers will likely feel no significant impact. Commercial and residential customers, however, would have to deal in some way with installation of appropriate metering technology. Such technology exists in various forms, from telephone communication of metering data, to radio broadcast of data to moving vehicles, meter readers, or radio networks. It is likely that no single solution will predominate; rather, differing solutions will apply depending upon variables including frequency of data collection and geographic location and dispersion of direct access customers.

ES-4.1.3 Information Requirements

The technical team dealing with metering and communications concluded that the type of information required and its delivery frequency varied with size of load and class of customer. Hourly information is needed to support hourly settlements for ISO imbalance charges, but there is disagreement about the source of this information. Some insist it must be metered individual

customers while others believe sufficient accuracy can be developed with load profile estimates. There was also disagreement over whether the hourly information must be finalized daily or over a longer time period to achieve this purpose.

Data is also required for the UDC and retailers to forecast hourly load to the ISO through scheduling coordinators. Interval metering data may need to be retrievable quickly to support very short run energy forecasts.

Hourly internal information is also necessary for customer billing purposes, both for billing by a retailer and by the UDC. This will be true even if load profiling of some customer classes occurs. Such data also is critical for customers to control usage as envisioned in the Policy Decision.

The UDC will require specific types of data, including kilowatt-hour, kilowatt, and kilovar data, since billing for distribution services and perhaps other items such as taxes and fees will require such information.

The metering system may need to provide information used for customer service, such as outage detection/restoration and power quality, and to support efficient use of the distribution system, including demand side management and interruptible load.

ES-4.1.4 Assessment of Installation Schedules and Costs

Given the fundamental issue of universal metering, the Metering and Communications Technical Team chose to conduct a high level assessment of the costs that would be involved in deployment of meters throughout California, in order to provide the CPUC with a general impression of implementation costs related to metering and communications. The report details the process and various assumptions used for that assessment. Variables accounted for included manufacturing lead times, length of the installation window, features of metering and communication systems, and capability and flexibility of the system.

The team gave a series of installation scenarios to several meter providers, ranging from 100% deployment of real-time meters over a one to five year period, to 100% deployment only for end users with demand over 100 kilowatts over the same time period. Many responses were submitted, but not every supplier provided a response to every scenario. The cost estimates ranged from $120 per customer for universal deployment in a one year period (but only one response to this scenario was submitted) to $450 per customer for deployment to customers over 100 kilowatts over five years. Chapter 8 provides a series of conclusions drawn from the survey.

ES-4.1.5 System Structural Alternatives

Extensive discussion surrounded issues relating to the structure of the metering and communications system. Several related key structural questions concerned ownership, control and performance of work on the system.

Some participants proposed that customers own their meters. Proponents of this position emphasize that meter selection, ownership and control is fundamental to direct access. Detractors assert that UDC's can bargain for superior prices and since the meter is part of the distribution system, the UDC must own it to prevent injury and damage. Others claimed meters should be owned by the UDC, emphasizing that the meter is only part of the communication system, which the UDC should also own and the benefits of which all customers reap. Opponents note that the UDC is not perceived as retailer neutral and can stifle competition by controlling the meter market. A third perspective advanced energy service provider ownership. Supporters assert that this would allow retailers to control their own information and to offer meter-related inducements to prospective customers. Those against this position expressed concerns about system reliability and safety and the risk that economically non-desirable segments of the market might never be served.

Issues surrounding control contain several subissues. One concerns who will actually operate, maintain, and install the metering and communications systems. An alternative for UDC operation is supported by scale economies and the assertion that all customers benefit from the communications system. Contraindicators include potential stifling of competition and the fact that this function can be performed by third parties and thus there is no need for UDC monopoly.

Metering system maintenance by the UDC also was suggested. Supporters note the UDC's extant expertise and equipment, and system safety and reliability. Opponents again note that this is an area where it is perfectly feasible for third parties to do the work.

It was also suggested that the UDC should perform meter installation. The pros and cons mirrored those concerning UDC control and maintenance.

ES-4.1.6 System Service Structural Alternatives

A key issue for decision is who will exercise control over the complete set of metering and communications system activities. Three models emerged from discussion, the first two with various alternatives.

The first model calls for control by a regulated entity, either the UDC or a monopoly information services provider (an "INFOCO"). A UDC with such control would have the same responsibilities with respect to the metering and communications system as the current utilities do, and would recover costs through rates subject to performance based ratemaking. The

INFOCO would be a regulated monopoly separate from other industry players but which performed a similar job as a monopoly UDC with respect to metering and communications, but perhaps in conjunction with metering of natural gas and water usage utilizing a common communication system to deliver data for billing and analysis purposes.

The second model calls for control by competitive entities. Alternative entities suggested were energy service providers or multiple competitive (not regulated) INFOCOs.

Under the third model, an information clearing house, similar to the VISA bank card system, would be designed and funded by all stakeholders. Such a clearing house could control the specifications of the metering function but contract out the actual work if its stakeholder directors so desired.

ES-4.1.7 Developing Standards for the Systems

The metering and communications technical team was only able to start on one of its key tasks, the determination of metering and communications standards. The report contains some discussion of issues in this area, including certain technical barriers to use of universal meter connectors, concluding with the suggestion that the CPUC sponsor an Electric Metering and Communications Standards Working Group to further address standards, with a report due by the end of this year.

This is not an area which requires invention from whole cloth. Standards established by independent entities, utilities, and governmental units already exist for metering devices and meter protocol translation. The new market may bring about the necessity to adopt standards for new innovations, however. Parties disagreed as to who should certify new technology, the utilities or an independent third party.

There also is not universal agreement concerning the communication standard that will be used for communications from the meter to the data collection point. Some parties argue for an open standard for such communications, while others believe the competitive marketplace should determine whether such an open standard is needed.

ES-4.2 Customer Billing

Many issues were highlighted in discussions concerning customer billing. Some issues overlap with the work of the Ratesetting Working Group and are addressed only briefly, both in the report and in this summary. Others deal with customer protection in the billing arena.

The basic unbundling issue is who will bill for customer energy services. One option is that the future UDC will send bundled bills not only for its distribution services but also for all other

aspects of service, which could include charges from a third party energy provider. A second option calls for bundled third party billing under which all energy service charges are billed by neither the energy retailer nor a third party billing agent. The third option envisions delivery of split bills, the UDC billing for its charges (including distribution, public goods, and during transition CTC), while the energy retailer bills for the services it provides. The alternative includes the option of the UDC or energy retailer contracting with the other to do consolidated billing.

Another set of billing issues deal with payment. Many common principles overlap in this area. They include security for payment, resolving billing disputes, and termination of service.

It is suggested that UDC's should be allowed to impose creditworthiness standards on retailers and their customers, as well as requiring security for payment. Those in favor of this alternative point to necessary protection of the UDC, while those against claim such deposits would be burdensome and may entail customers assuming unknown risk for retailer activity. Another security alternative is use of a statewide insurance risk pool, which might be either voluntary or mandatory.

A common theme runs through a number of payment and termination subissues: What is a customer's responsibility if it pays UDC charges to its retailer but the retailer does not in turn pay the UDC? This question arises in relation to payment of bills, UDC resort to security, UDC administration of credit requirements, UDC/end user billing disputes, retailer/UDC disputes, and termination of service to the retailer or the end user. One alternative suggested in such situations is for payment to come from the retailer, then if necessary from security, and finally if necessary from the end user. Proponents note that such a system is presently in place in the gas market and thus would be in line with current CPUC policy. A variant on this alternative suggests one change: if an end user can prove (through some appropriate expedited mechanism) that it has already paid the UDC charges to its retailer, it is forgiven in the billing dispute and will not face termination. Supporters note that it is better that the risk of such nonpayment be spread across the entire UDC customer base than fall on an isolated innocent customer.

Many other billing issues were very briefly discussed and are addressed in Chapter 9. They include change of service rules, end user/retailer disputes, third party termination policy, late and delinquent payment policies, standardization of billing formats and procedures, potential billing enhancements in the new market, and billing inquiries.

ES-5. Ensuring Meaningful Customer Choices

ES-5.1 Aggregation of Customer Loads

In aggregation, the loads of two or more customers are grouped together and matched with one or more generation facilities. Access to aggregation may be vital in the new marketplace, since it may be the only vehicle through which small customers can participate in direct access. However, the availability and governance of aggregation are not without controversy.

One set of issues concerns the tension between the desire to keep aggregation costs down so that customers can use aggregation to gain direct access benefits, and the competing aspiration to avoid cost-shifting which might result from cost reduction strategies. Two principal cost-reduction strategies emerged: avoiding universal metering through load profiling of smaller customers and communications systems, and unbundling some portions of the metering and billing parts of UDC services to minimize duplicative costs. There were concerns expressed, however, that any cost reductions so achieved not result in shifting of costs to other customers who do not participate in direct access. Mechanisms suggested to avoid cost-shifting included requirement of upstream metering between a set of customers and the transmission system, requiring use of precise load profiles, and requiring universal metering (although use of the final alternative obviously eliminates load profiling as a cost reduction strategy).

DAWG participants also discussed proposed aggregation models concerning both competitive and local governmental providers.

Four competitive providers models were proposed. The first calls for a standard business pattern where competitive providers are unconstrained in geographic area served, affiliation, or membership in other organizations. The second would require providers to be confined to specific service areas in order to solve data problems related to allocation of settlement costs. The third recognizes that some aggregation groups may form based upon affinity of end users (for instance, professional associations or community organizations). The final alternative proposes a two step process under which utility affiliate aggregators would at first facilitate and later participate in the market, providing the UDC an incentive to promote development of the competitive retail market.

Three alternatives in local government provision of aggregation services emerged. The first would entail new legislation to allow local governmental units to act as the default aggregator within their boundaries, but perhaps without the same authority or distribution system of traditional utilities. Under the second approach, “municipal lite” utilities would be formed, owning little of the existing distribution system but eligible to purchase power wholesale. The third option involves formation of joint powers agencies to act as electricity providers.

The final aggregation issue involves market rules for aggregators in addition to other applicable market rules. One area concerns rules to put into place to ensure the accuracy of load profiling, if allowed. Another area addresses aggregator cooperation with UDCs and scheduling coordinators in order to gain a better understanding of transmission/distribution interface loads after the formation of the ISO and PX. This could require cooperation in the installation of upstream meters and access to resulting information. A third area addresses whether a written contract

specifying the obligations of aggregation customers is necessary and if so, the scope of its terms. The final aggregator market rules issue concerns whether issues may emerge if an aggregator provides both electricity and natural gas to a single customer.

ES-5.2 Consumer Education

Consumer education is essential in the transition to the new market, especially for smaller customers.

The CPUC may need to assume a central role in this area, as it did in telephone deregulation. It must require such education and monitor it for efficacy and threats of abuse. It should establish a system that will involve community-based organizations to assure appropriate message dissemination which is multi-lingual and culturally sensitive. The basic message involves five essential elements: alternative supplier availability; customer right to choose; need to assess risks and benefits; need to understand individual usage data to be provided by utilities; and use of energy shopping information to be provided by the CPUC and the market.

Not all agree that education should primarily be a CPUC responsibility, pointing out that expense for the CPUC could be quite large. Some such parties prefer to rely upon utilities, while others suggest all market participants have various appropriate roles. Utility participation is advanced on several bases. One is that customers will expect it and blame the utilities for failures regardless of their involvement. Another is that the utilities have the resources and experience to mount a major campaign.

Those in favor of relying on market participants raise questions about utility objectivity. They also point out that each market participant should be able to provide messages they perceive to be relevant and effective.

A final alternative is to rely upon the Consumer Education Trust to conduct customer education. Such a trust is discussed in the Policy Decision but does not yet exist. The report summarizes and compares two past trusts, the Telecommunication Education Trust and the Deaf Equipment Acquisition Fund. It is suggested that work on establishing the trust begin immediately.

ES-5.3 Consumer Protection: Effective Consumer Redress

Consumer protection will still be necessary in the new electricity marketplace. One key requirement will be the opportunity for consumers to have access to effective no-cost redress for complaint resolution. Such redress, which should accommodate limited and non-English speakers, should occur in a neutral forum, but mediation should be encouraged. Monetary and licensing penalties should be available, with monetary penalties imposed upon providers to be used for consumer education or advocacy.

ES-6. Monitoring and Oversight of Implementation

DAWG recognizes that since this report does not propose a single integrated solution to the challenges posed by the implementation of direct access, at some point a final implementation plan must be developed. Arriving at such a plan would require sifting the proposals advanced in this report and others that surface during the comment period to follow, arriving at a specific plan for at least the initial implementation period. This report suggests several alternatives to arrive at the final plan. These include continuation of working group efforts in the future, CPUC adoption of the final plan, or CPUC decision on certain enumerated key issues to provide direction for future working group activity.

This report recommends CPUC institution of a monitoring program to assess the progress of the implementation of direct access. Whether direct access is made available universally all at once or is phased in, monitoring will be vital to the success of the CPUC's vision of a fully competitive generation market in California.

Chapter 1. Introduction

1.1 Objectives and Theme of the Report

This Report from the Direct Access Working Group represents half a year's effort from scores of parties, focusing on the problem of how to implement consumer choice. Although the Report is a compendium of many ideas and not a consensus, there is general agreement on the issues that the Commission must address. The Report presents the key issues that require resolution to implement consumer choice, plus a range of alternatives for addressing each issue.

The CPUC's stated goal is to implement direct access for all consumers as rapidly and equitably as possible, while maintaining system reliability and safety, with prompt implementation of direct access for all consumers delayed only to the extent technical obstacles make it necessary (CPUC Decision 95-12-063, p. 69). No party to the working group has challenged this goal.

The parties do differ, however, on how quickly and thoroughly this goal can be met. Some believe that rapid movement to direct access and choice for all consumers is both feasible and essential, and that efforts to define or control the marketplace will only delay consumer choice and impede market-based solutions. Others argue for a slower implementation, based on the premise that potential problems need to be anticipated and resolved before full customer choice should be accommodated. This dichotomy underlies the array of alternatives that comprise most of the Report.

1.2 The Key Issues and Positions

Although the length of the Report and the number of alternatives may appear daunting, the existence of multiple alternatives should be viewed not as a roadblock to implementing customer choice, but as a range of options — a *tool kit* — that may be applied to specific issues once the Commission chooses the policy approach that it wants to govern implementation.

The comprehensive presentation of this Report is consistent with the direction the Commission provided at the July 9, 1996 checkpoint meeting, at which the presiding Commissioners asked that all views be reported. In the spirit of that request, the Report is in a *pro/con* format, where the statements were submitted by parties advocating the various alternatives. The Commission should understand that in many instances there may be no agreement that the contents of the pro/con statements are accurate or correctly explain the issues.

The present section identifies the issues that emerged during the working group process as most crucial for implementing direct access. This list is not intended to be exhaustive, and different parties may have different opinions on which ones are of greatest importance. These issues are,

however, the ones that received the greatest emphasis in the working group meetings. In later chapters the Report examines these issues and parties' positions on them, and tries to place the proposed solutions in the context of the underlying philosophical difference mentioned above.

The six key issues identified here are:

1. Phase-in of consumer choice and eligibility to participate;
2. Consumer access to market price signals and use of hourly metering;
3. Competition in the supply of services unbundled from distribution;
4. Aggregation;
5. Availability of market information; and
6. Consumer protection and education.

1.2.1 Phase-in of consumer choice and eligibility to participate

The primary issue that this Report addresses concerns whether customer choice should be limited initially and phased-in over a period of years. If the Commission concludes that it will implement less than full customer choice for some period, then the Report presents a broad range of alternatives for limiting that access. Under the Commission's Policy Decision, the crux of this issue is whether or not there are truly any insurmountable technical limitations that prevent full customer choice sooner than the decision's timetable.

The parties disagree substantially on the need for a phase-in period and the criteria that might be used for equitably rationing consumer choice (e.g. limiting consumer choice to a certain total amount of capacity, or a certain total number of transactions). Some parties are concerned that technical limitations may exist if many consumers desire to exercise choice. Others are concerned that the focus of the Commission's policy on consumer choice should be on how to provide that choice, not on rules to limit the exercise of choice. The Commission will need to examine the reasons given for limiting consumer choice and determine the extent to which such limitations may be necessary.

1.2.2 Consumer access to market price signals and use of hourly metering

The parties agree that hourly interval metering and real-time pricing via electronic communication systems provide the best information to consumers to enable them to make market decisions. Many parties believe that these meters and associated electronic communication systems should be universally deployed for all customers, and not just for the larger commercial and industrial customers for whom the CPUC has already made this decision. Parties are not in agreement, however, about the feasibility, timing and financing for deployment of metering.

In addition to a metering alternative, this Report offers alternatives to interval metering, including the use of load profiles, which rely on estimated patterns of use. Load profiles have the advantage of avoiding the cost of new meter installation, but the disadvantage of providing inaccurate information about actual customer usage, thus disabling consumers from taking advantage of price signals. Load profiles also place reliance on using regulators to ensure that the load profiles are accurate and do not shift costs unduly. On the other hand, the inaccuracy of load profiles may actually stimulate more rapid movement of consumers to the market to escape those profiles. The Commission will need to explore the alternatives for providing price signals to consumers that take best advantage of a competitive market.

1.2.3 Competition in the provision services unbundled from distribution

Although the Ratesetting Working Group is primarily addressing the unbundling of distribution services, that work directly affects several Direct Access Working Group issues, including the method of billing and metering available for consumers who want to exercise choice, the use of credit and security to protect consumers and the extent to which these services are available in the market instead of from regulated utilities. These issues are discussed at length in Chapters 8 and 9. For consumers, the key to resolving this issue is to ensure the same or better customer service and revenue processing efficiencies than exist today. For suppliers, billing for services directly represents an ongoing customer contact that is standard practice in most industries. The Commission will need to explore the alternatives presented here, consistent with its general policies on the extent to which it wants to provide consumers with choice and the extent to which it wants to continue regulated service in lieu of the competitive market.

1.2.4 Aggregation

Aggregation is nothing more than a supplier serving more than one consumer. Some call this retailing. It rises in policy importance because abbreviated, standardized contractual relationships may reduce overhead costs sufficiently to enable small customers to participate in direct access. Aggregation becomes more complicated by a variety of issues, including (i) whether customers can be involuntarily aggregated, (ii) who should be the default supplier and on what terms, and (iii) how is aggregation addressed when the customers being aggregated do not all have hourly metering. Again, the Commission's philosophy on the basic tensions discussed in Section 1.2.1 will permit it to address these aggregation issues. For example, if the Commission seeks to maximize consumer choices, forced aggregation may be inconsistent with Commission policy. To the extent that the Commission seeks to maximize price signals to consumers, aggregation of those without hourly meters may become a short-term, bridge issue. If the Commission wants to minimize regulatory intrusion into the competitive market, it might choose to minimize the types of services that a default supplier may provide, leaving the rest to the competitive market. The alternatives presented in Chapter 10 present the Commission with some choices in how to apply its general policies to specific aggregation issues.

1.2.5 Availability of market information

The competitive market is facilitated by ensuring the availability of trustworthy market information, both to consumers and to competing energy service providers. There are at least two forms of needed information: information about products and services and the companies offering them, and information about consumers and their interests for use in marketing. The less available (or more costly) this information is, the slower the market is likely to develop. Thus there is a tension between, on the one hand, the availability of customer information to competing marketers (thereby increasing the likelihood that consumers can take advantage of the market), and, on the other hand, concerns about consumer privacy protection. The Commission will need to address and balance this tension.

1.2.6 Consumer protection and education

The parties generally agree on the need for consumer protection measures. Consumer protection involves a tradeoff between facilitating a competitive market, on the one hand, and establishing greater regulation that may provide more consumer protection but might also interfere with viable marketing. The Commission will need to explore this tradeoff to find ways that consumers can be protected without turning the proposed competitive market for energy services into a regulated industry or deterring responsible marketing. Chapter 12 discusses alternative ways of addressing this tension.

Parties generally agree that some explicit consumer education program must be developed and implemented as part of the transition to direct access, and also for retail distribution unbundling if the Commission makes such a policy decision. Parties are less clear about what institutions should design and implement educational programs, although most would agreed the Commission is responsible for them. Parties are perhaps least clear about how market rules and practices themselves can be designed to support consumer learning and to facilitate meaningful choices and intelligent decision-making.

1.3 The Need for a Governing Policy Approach and a Conforming Implementation Plan

As noted above, the alternatives described in this Report are not presented as complete packages of solutions that would resolve all issues in a consistent way. The Report presents a series of discrete issue with alternative resolutions for each. There are a few unifying themes, however. As discussed in Section 1.1, each alternative arises from an underlying policy basis that is driven primarily by philosophical differences in two areas: (1) between a prompt implementation of consumer choice for all consumers and a more deliberative approach that anticipates and seeks to

minimize potential problems; and (2) on the range of regulatory involvement that should take place in a market that is being opened for competition. Resolution of these philosophical differences would therefore be a logical first step for the Commission in developing a coherent implementation plan.

The Commission would do well to begin its review of this Report by considering its basic policy approach. Then, having established its governing policy, the Commission will be able to assess, in detail and in a consistent manner, the alternatives presented for the various issues. We expect that many of the September 30, 1996 comments, provided by participants in the working group and other parties, will suggest ways to integrate the elements of this Report to create internally-consistent plans for implementing consumer choice. Again, having established a governing policy approach, the Commission will be able to use this Report as a reference to aid its understanding and evaluation of the alternatives that will surface in the coming months.

In addition to the direct decisions this process leaves for the Commission to make as a result of lack of agreement among DAWG participants, there are additional, closely connected decisions on rates, unbundling, and consumer protection and education, that must be coordinated so as to have the basis for issuing its final guidance for retail restructuring. The Ratesetting Working Group will present several alternatives about the scope and process for UDC distribution function unbundling. However the Commission resolves that dispute, rates for all customers need to be in place by Fall 1997 to permit direct access to begin. Furthermore, the remaining deliverables from the DAWG (consumer protection report on October 30, consumer education trust report on December 6, and proposed standards for metering and communication systems at some yet to be unidentified date) must all be adjudicated by the Commission and woven together into a coherent retail restructuring strategy by June 1997.

Finally, having decided its governing policy approach and its preferences regarding the various alternatives presented, as well as coordinating with other elements of the restructuring process that interact with direct access, the Commission will need to decide how to approach the problem of formulating its preferred conforming implementation plan. In the first pro/con presentation of this Report, we offer a number of possibilities the Commission may wish to consider.

1.3.1 ALTERNATIVE: Reconvene Working Group Efforts in June 1997

Some working group participants believe that the UDCs and other parties must collaborate in a working-group format in June, 1997, after a further set of decisions has been provided by the Commission and the Federal Energy Regulatory Commission. The purpose of such a working group effort would be to develop a final conforming implementation plan based on the DAWG report and the decisions made by the CPUC and FERC in the spring of 1997.

Alternative 1.3.1 PRO: There is concern among some parties that the CPUC may lack the necessary resources to develop all the details of such a final plan for each of the IOUs.

Alternative 1.3.1 CON: A working group of diverse stakeholders is unlikely to reach a consensus position on the specifics of an implementation plan, just as consensus was elusive in this report. In addition, continuing this work through working groups will create delays that may impair the Commission's ability to implement restructuring by January 1, 1998. Lack of consensus between members of the current working groups indicates that many issues will remain contentious, and will probably require hearings anyway.

1.3.2 ALTERNATIVE: A CPUC Decision Follows Review of This Report, Initial Comments, Reply Comments, and Possible Further Hearings

Some parties believe that, after considering the input provided by this report the CPUC must adopt and issue a final conforming implementation plan based on this report, the comments to it, and any related restructuring decisions made by the CPUC and the FERC, with a public comment period to follow issuance of a draft implementation plan.

Alternative 1.3.2 PRO: This approach would optimize the resources of many stakeholders who are already stretched near the breaking point and who would be even further frayed by the time any future implementation plan collaboration would occur. Parties with limited resources would likely be under-represented in a new collaborative effort, which is a concern that has been expressed by certain Commissioners regarding the current DAWG process. This approach is also the most expeditious.

Alternative 1.3.2 CON: Resources also are taxed at the CPUC.

1.3.3 ALTERNATIVE: The CPUC Reaches Implementation Decisions in Stages

Many parties believe that the Commission must reach a decision regarding certain issues before the commencement of any further working group collaboration. Without such decisions, a future collaboration would not aid in advancing implementation of direct access. Examples of key issues for possible initial resolution by the CPUC include:

1. Does there need to be a phase-in period of direct access eligibility, and if so, over what time frame?

2. If there is a phase-in period, what methodology will be used to determine customer eligibility?

3. Will every customer wishing to participate in direct access be required to make use of an hourly-interval meter, or can load profiles be used for certain customers in lieu of this metering capability?

4. Will utilities be able to recover implementation costs incurred as a result of restructuring, and if so, how?

5. Will the Commission move immediately to universal hourly-interval metering to take advantage of cost and efficiency advantages, or wait until some customers have installed them on their own?

6. Will distribution services be unbundled to enable retailers to offer a more varied set of service options, or will UDCs continue to have a monopoly over them?

Alternative 1.3.3 PRO: A sequenced set of decisions could enable a more thorough review and discussion of the most important elements of direct access implementation, thereby reducing the pressure for a single decision on all elements of implementation under a rushed schedule. Such a plan would balance further working group collaboration with specific CPUC guidance on key issues.

Alternative 1.3.3 CON: It may be difficult to prioritize issues for decision and could delay the timetable proposed at the April 22, 1996 Scoping workshop. In addition, any delay in deciding key issues will delay implementation of opportunities dependent on those outcomes.

1.4 The Elements of a Comprehensive Direct Access Implementation Plan

Through its discussion of alternatives, this Report presents the key steps necessary to implement consumer choice. As an additional way of reviewing the issues that affect consumer choice, it is also useful to look at the steps that must be taken to permit consumer choice. These steps may be grouped into six categories:

1. Market transformation requirements;
2. Program design and regulatory approvals;
3. Customer education;
4. Consumer decision to exercise choice;
5. System verification prior to commencement; and
6. Program operation and monitoring.

Many of these steps may require utility resources to be devoted to direct access facilitation, resulting in costs that need to be recovered through some means as yet undetermined. It may be appropriate for the "trust" arrangements now being finalized for ISO and PX development costs to also encompass retail restructuring expenditures.

As a practical matter, both the length of time and the resources required to conduct some of these efforts will depend on the volume of customers choosing to engage in direct access. In addition,

there may be unforeseen complications that necessitate adjustments once implementation of these efforts is underway.

1.4.1 Market Transformation

The CPUC's proposed reform requires transforming centrally planned electric systems to a competitive market structure and the unbundling of industry structure and services. To accomplish this successfully, it is necessary to address a number of key issues, most of which are the subject of this Report, including the potential for customer confusion, poor market information, and unequal access to the market. (Such transformation also requires putting in place the necessary upstream structures to ensure a well functioning market that permits customers to make meaningful choices and leads to least-cost outcomes. Those upstream issues are being addressed by different working groups and are not subjects of this Report.)

For purposes of this Report, the primary aspects of market transformation are:

1. Enabling customers to overcome the transaction costs barriers to participation in markets;
2. Customer education programs that assist in reducing market barriers and that provide an understanding of the procurement and unbundling of services;
3. Unbundling of transmission, distribution, generation, and customer services, and pricing, metering, and billing mechanisms for all unbundled services;
4. Differentiating the services that will be regulated and unregulated; and
5. Providing consumers with meaningful choice, i.e. the potential to achieve significant value-added services, through price or quality differences, in the selection of market options.

1.4.2 Program Design and Regulatory Approvals

To effect consumer choice, the Commission needs to put in place the regulatory structures that accommodate that choice. The essential steps in this process include:

1. The CPUC must issue decisions on direct access procedures (including, if the Commission determines it to be necessary, eligibility criteria, phase-in schedules, customer class representation requirements, over-subscription allocation procedures, and metering requirements);
2. The CPUC must approve revised tariffs for direct access customers setting forth those procedures and segregating generation and transmission services from distribution services, and must develop a mechanism to collect CTC revenues which is compatible with direct access;
3. The FERC must issue complementary approvals to allow various features like the ISO and Power Exchange to be relied upon for direct access; and
4. Utilities, customers, retailers, marketers, suppliers and other market participants should attempt to collaborate on the implementation of the decisions made by the CPUC and FERC.

1.4.3 Consumer Education

Consumer education is a necessary prerequisite to effecting direct access that provides customers with meaningful opportunities. This education process will require the creation of an Independent Education Trust Fund to be used for customer education. As discussed in Chapter 11, the key steps in consumer education are:

1. Identifying the scope and content of desired customer education and notification requirements;
2. Creating the Independent Education Trust, clarifying its responsibilities versus those of other parties, and beginning its operations;
3. Supplementing the customer service functions of the utility distribution companies to address a wide range of market structure, rate, and direct access inquiries; and
4. Initiating programs involving education through individual customer mailings and/or media presentations.

1.4.4 Consumer Decision to Exercise Choice

Beginning some time before direct access is actually available, and continuously thereafter, consumers will have the opportunity to elect to exercise choice. This will require the consumer to take certain specific steps:

1. Provide proper written and verified notification to the distribution company;
2. Sign any agreements necessary with respect to obligations to pay transition costs;
3. Provide for changes in metering, where necessary or desired;
4. Enter into appropriate commercial transaction with other energy service providers.

Additionally, the distribution company may have some steps it is required to take, including:

1. Verify that the metering and communication system meet standards and perform properly (where applicable);
2. Ensure that appropriate billing system entries are made to enable billing as desired by consumer;
3. Adjust load forecasting assumptions where necessary to reflect a different energy service provider; and
4. Provide a system to allow a customer to change to utility distribution company default service or to another service provider smoothly and efficiently.

1.4.5 Systems Verification Prior to Commencement

Before direct access can begin, it will be necessary to ensure that the various hardware and software systems are in place for billing, metering and ISO/PX operation and interface. This pre-operational checkpoint should include ensuring that:

1. ISO-based scheduling, settlement, and ancillary service procedures are operational, including completion of computer software development, testing, and hardware installation to perform functions;
2. Scheduling coordinator procedures are operational, including completion of software development, testing, and hardware installation to perform functions;
3. Billing system procedures that permit direct access and consumer choice are operational; and
4. Load forecasting system procedures and responsibilities are operational.

1.4.6 Program Operation and Monitoring

Once the program is initiated, the CPUC will monitor its operation to assess necessary changes to the system, and, if not all consumers are eligible for direct access, to determine whether any scheduled phase-in should be modified. Additionally, the CPUC will monitor the success of adopted consumer protection measures, the utility distribution company's performance of its default supply responsibilities and the UDC's activities in promoting consumer choice. The CPUC's monitoring plan discussed in detail in Chapter 13.

1.5 Assessment of Consumer Interest in Direct Access

Design of a direct access program is being addressed in the absence of fundamental information about the degree of consumer interest in participating in either physical direct access, virtual direct access, or contracts for differences. Although we have anecdotal information of substantial interest in direct access for industrial and large commercial consumers, we cannot extrapolate their interests to the consumer population at large. Stated simply, we will not know the scope of consumer interest in direct access opportunities until the program is actually underway. Moreover, irrespective of consumer interest, we have little understanding of the whether marketing and energy service providers will be interested in providing services under the conditions established by the structure of the decisions made by FERC, the CPUC, scheduling coordinators, and the UDCs.

While there are many alternative proposals involving numerous specific design elements, most participants agree that one cannot expect large proportions of consumers to elect to participate in direct access in the initial year. Some believe that it is unrealistic to assume that large numbers of consumers are willing and prepared to elect direct access in light of the many uncertainties of the costs and benefits this might provide for them. Others believe that the necessary systems of metering and communication, billing, submission of balanced loads and generator nominations,

and ISO imbalance cost settlement procedures cannot be in place with sufficient capacity to support large numbers of consumers, even were they to be interested.

This disagreement and uncertainty about the degree of consumer interest in direct access is at the heart of the philosophical disagreement that has generated the disparate views on the speed and scope of implementation of consumer choice. For example, as a consequence of the belief that demand for choice could be high from the outset, some propose elaborate safeguards and restrictions on eligibility to exercise choice.

It is desirable to have the best understanding we can gain about consumer interest in exercising choice. Meaningful information probably cannot be obtained until a consumer education process is well underway and consumers have a better understanding of their options. However, even this information is likely to be marginally predictive of true consumer response once consumer choice is actually implemented and service providers develop packages of service options for consumers to choose from. Thus, although it is desirable to gather market information now, the information gathered should be used as a tool to guide policy, not as a prediction or a final determination.

The market research effort that this implies can involve varying degrees of stakeholder and regulatory involvement to develop the method and content of surveys, the level of consumer education in advance of the survey, the timing of any survey, the assessment of the survey results, and the financing of the costs of that work. The Direct Access Working Group encourages the Commission to consider whether such market assessment is desirable and the degree of stakeholder involvement that is desired in conducting such an assessment, which could range from a completely regulatory-sponsored assessment, to an assessment developed by a stakeholder advisory committee with regulatory oversight. This work should be considered in the context of the larger consumer education program discussed in Chapter 11.

1.6 Continuing Role of the Commission

The Commission's immediate role in developing policy to implement consumer choice is obvious. Its continuing role once consumer choice is in place is less obvious, but should be made clear. That role includes (i) monitoring the success and problems of the programs in order to identify changes that may be required (Chapter 13), (ii) developing and implementing continued consumer education activities as may be required to supplement what the competitive market makes available on its own (Chapter 11), (iii) assessing issues relating to continued system reliability, as it pertains to existing utility generating assets, and considering ongoing market power concerns relating to the transition to a competitive market (a subject of separate applications before the Commission), and (iv) participating in consumer protection measures to address the potential for wrongful conduct by market participants (Chapter 12).

1.7 About This Report

This Report provides background on most topics crucial to the implementation of Direct Access, and in many cases, presents specific alternatives advanced by particular parties. The Report thus offers the Commission numerous options from which it can select the features to develop many different Direct Access programs.

1.7.1 Role of Comments from Parties

This Report does not attribute positions to any particular party. Nor does it present integrated solutions. It is for the parties in their comments to tie together the various alternatives in this Report into a package that is internally consistent and provides the Commission with an understanding on how all of the pieces presented in this Report fit together.

Parties should be expected to advise the Commission on their recommendations and rationale on what a complete package of solutions to these issues should consist of in their September 30, 1996 comments on this Report. These comments will provide the Commission with the input necessary to permit it to evaluate the issues and are an essential tool for the Commission to reach any conclusion on the issues discussed in this Report.

1.7.2 Issues Not Addressed

The Direct Access Working Group discussed two items which were determined to be outside its purview. The question was raised as to whether direct access could or should proceed on 1/1/98 irrespective of the completion of various foundational underpinnings such as the Competition Transition Charge (CTC). Since this issue is already being actively addressed elsewhere and would have been a distraction from this Group's work, it was rejected. The question of "pilot programs" was also raised. This was rejected as diverting attention from the key issues of implementing direct access as widely as possible by January 1, 1998.

Chapter 2. Meaningful Choices for Consumers

This chapter addresses several areas that are important if consumers are to have meaningful choices. Simply having choices does not ensure that these represent actual differences which provide opportunities for customers to select lower cost options or higher value options according to their own tastes and preferences. Whether there is a good range and diversity of choices which customers are offered depends upon the structure of the market, including the requirements placed on suppliers of services. Even with good choices, however,there is no assurance that customers will understand or be able to easily exercise those choices; this is highly influenced by the information environment of the market. Designing markets that provide opportunities for choice to consumers, with plentiful options, and sufficient information about options and the capability to make intelligent choices is what makes choice meaningful.

This chapter contains three sections. Section 2.1 provides an overview of major policies to achieve consumer choice. Section 2.2 provides ten consumer principles that DAWG developed to guide much of the thinking of this forum. Section 2.3 describes a market transformation perspective to ensure that as markets evolve that they ultimately achieve their intended goals.

2.1 Policies to Achieve the Goal of Meaningful Consumer Choice

There are several policies that the CPUC has adopted in order to provide some of the benefits of restructuring to all customers. The intent of these policies can be interpreted as consistent with a comprehensive goal for all of electricity restructuring -- that the result of restructuring be a higher level of societal economic efficiency than could have been obtained in the traditional paradigm of utility structure and regulatory oversight.

2.1.1 Adopted CPUC Policies

The CPUC adopted several policy statements that clearly are intended to ensure that consumers achieve some of the benefits of restructuring. These include:

a. a five year rate freeze at 1/1/96 levels;

b. no cost shifting among customer classes;

c. representation from all customer classes in eligibility for direct access; and

d. ensuring that competition is genuine and that markets are open to competitive entrants;

e. ensuring that consumer choices are well understood and easily exercised;

f. shift in consumer responsibility from a utility ratepayer to an intelligent, self-interested customer;

g. dedication of the CPUC to creation and operation of consumer education and consumer protection programs.

Development of proposed activities and implementation mechanisms to achieve these policies was left to the working group processes, with the understanding that the CPUC would review and select appropriate policies from among the recommendations provided.

2.1.2 Societal Economic Efficiency

A framework for looking at these and other policies is the concept of societal economic efficiency to guide policy decision-making. This can be viewed in two parts.

First, the major structural decisions for the industry and the specific implementation details should be designed to accentuate economic efficiency compared to the old industry/regulatory structure. For example, the policy decision relies upon competition in wholesale supply of electricity to reduce these costs, but notes that concentrated ownership may lead to market power problems. Reductions in utility ownership of generating facilities and requirements that UDCs purchase from the PX are mitigating actions designed to achieve more efficient markets. Similarly, decisions to require equivalent access to customer information for marketing purposes stems from a desire to achieve competitive, and presumably efficient, retail markets. Substantive issues of market power in retail markets remain to be resolved.

Second, the "societal" prefix before economic efficiency denotes an interest to bring broadly shared societal values into this economic efficiency perspective. Generally this "societal" prefix is associated with economic justice, longer run time perspectives than competitive markets usually follow, concern for internalizing externalities for non-priced resource use or impacts from decision-making, etc. The introduction of competitive forces must support, rather than jeopardize, existing and evolving social values.

During this century, California has established certain social and equitable goals that it deemed as necessary components of electric restructuring. Among these are special "lifeline" rates and services and safeguards for low-income customers, the elderly and disabled. These goals should be preserved in a restructured environment even if the mechanisms are changed. The move to a competitive electric marketplace has been described as ensuring lower costs than the regulatory paradigm, as practiced by California, has been able to accomplish. However, social goals must be preserved, lest restructuring devolves into a pretense for abandoning 100 years of equitable policies established by the people of this state.

Determining how to apply this societal economic efficiency framework is difficult. An example of tradeoffs can be found in the indepth discussion of access to customer information in Chapter 7. Access to customer information reflects the tension between the pure economic efficiency arguments in support of providing customer information to enhance market development versus the social value of personal privacy.

A balancing of social values versus economic interests is implicit in using a societal economic efficiency framework to guide specific restructuring policy decisions. As retail market issues are examined, many other conflicts between social values and economic interests will be encountered, and a more explicit use of societal economic efficiency may be useful in guiding resolution. The challenge for all participants in these working groups is to help to design new mechanisms to achieve societal goals in a way that is compatible with competitive market structures and the major responsibilities of the market players as defined by the CPUC's policy decision.

2.2 CONSUMER PRINCIPLES FOR RESTRUCTURING

The broad policies of D.95-12-063 and the overarching goal of societal economic efficiency described above must be translated into more tangible operational principles if they are to provide practical guidance to the restructuring proceedings. DAWG participants developed ten principles which could be support by most participants. Each of them can be agreed upon in general terms, but efforts to interpret them by defining terms and elaborating the details led to controversy that could not be resolved.

This report provides a description of the generally accepted principle, provides additional interpretative language sponsored by one or more parties, and with "pros and cons" for this additional language. Further refinement of the interpretation of these principles and their motivation for proposed consumer education and protection programs will be made in the consumer protection report that is scheduled for submission on October 30th.

Despite lack of unanimity concerning the detailed implementation of these principles, they were forwarded to the various technical committees and used by them in developing specific proposals and options. These principles provide considerable guidance to the assessment of alternatives through the "pros and cons" discussion of each alternative throughout the report, but especially in the market rules chapter and in the final chapters of this report.

The remainder of this section will present each of the ten principles, any interpretative language that has been suggested, and then provide "pros and cons" to understand why that interpretation is supported or opposed.

2.2.1 Right to Know

Customers must be assured of access to affordable, accurate, and multilingual informational and educational materials which enable comparison of price, quality, service record and terms of service offered.

2.2.1.1 ALTERNATIVE: Suggested Interpretation

Such materials must be readily available to all customers, at no cost, and must be disseminated in various languages through multiple media intended to reach different customer groups. The materials must contain all basic information necessary for customers to make informed decisions about electricity suppliers, including different suppliers' previous experiences in the market and track records. The market offerings of all market participants should be included in these materials.

Alternative 2.2.1.1 PRO:

In order for a competitive market to function, customers must have adequate information upon which to make choices. This information must be readily accessible, understandable and adaptable for comparison purposes.

Alternative 2.2.1.1 CON:

1. Requiring that every customer has access to materials at “no cost” creates a potentially large burden on those responsible for funding informational and educational activities. Creating that burden at this time is unreasonable, without first understanding who will be burdened, and the extent of the Commission's informational and educational policy decisions. Instead, the Commission should recognize that the intent of the term “affordable” means that for those who cannot afford to pay for information and education, and where the Commission determines it to be necessary for all, "no cost" materials should be made available.

2. Materials developed to help customers (e.g. large industrials) make direct access decisions should be provided at affordable prices.

2.2.2 Right to Choice

Customers should have choices involving real tradeoffs of quality or quantity versus cost.

2.2.2.1 ALTERNATIVE: Suggested Interpretation

All customers should have the ability to aggregate efficiently on a non-discriminatory basis. Customers should have choices which offer substantial savings and identifiable value.

Alternative 2.2.1.1 PRO:

Choice must be meaningful, i.e. offering true differentiation and sufficient value for which making a choice is deemed desirable. For small customers, market choices will be limited unless they can exercise some market leverage. This leverage will come only through aggregation. Moreover, vigilant supervision of the nascent market will be necessary to ensure that barriers to competition have not been intentionally or inadvertently constructed by market players or by regulatory policy.

Alternative 2.2.2.1 CON:

1. Electric industry restructuring will not and should not be expected to provide substantial savings and identifiable value to all customers. For some, choices will be limited, with default service provided by the UDC quite possibly the best choice available. In fact, as inter- and intra-class subsidies are attacked by retailers, those who have traditionally received the greatest subsidies may well find an increase in service costs. The Commission should therefore not saddle itself with a principle requiring all customers to receive substantial savings and identifiable value. Instead, it should make policy decisions to improve the societal economic efficiency of the electric industry overall.

2. Aggregation is unlikely to result in better prices that those from the power exchange, and therefore savings beyond those from the power exchange market should not be anticipated.

2.2.2.2 ALTERNATIVE: Suggested Interpretation

It is insufficient that choice be provided to customers at large, because this excludes communities that are traditionally underserved. Where competitive services are not available to certain customer groups, barriers to competition that prevent access by these customers must be eliminated. This may require affirmative efforts outside of normal market forces. Monitoring mechanisms, analogous to the anti-redlining regulations currently in place for large insurance companies operating in California, should be instituted and analyzed annually for enforcement purposes. Discrimination by providers based on race, gender, ethnicity, and other unlawful categories must be discouraged through appropriate sanctions and penalties.

Alternative 2.2.2.2 PRO:

As opposed to outright discrimination, more subtle exclusions from a full range of choices may be made for various underserved communities. An affirmative effort to ensure that a full range of choices is offered throughout California should be undertaken.

Alternative 2.2.2.2 CON:

1. As discussed in several DAWG meetings, it is unrealistic to expect all competitive providers to offer services everywhere in the State. Providers will target customer groups that they seek to serve.

2. As with any new start up businesses, the initial market activity could be quite limited, therefore all customers will not be reached with new options.

3. Because of the metering and data communication issues, it may be substantially more expensive to serve customers on a piecemeal basis than on a geographic area basis.

4. Affirmative efforts suggest funding of programs which may divert attention from developing the market itself.

2.2.3. Fair Dealing

All classes of customers should have access to choices and pricing options without discrimination.

2.2.3.1 ALTERNATIVE: Suggested Interpretation

Affordable service options must be responsive to customer needs and performance must be verifiable. Slamming, excessive rates, over-billing and other marketing abuses which exist in the telecommunications area must be prohibited and met with severe sanctions, including license revocation, penalties, full restitution to the customer, and a fund for community education. Energy providers must be made responsible for the actions of their agents or representatives. Geographic rate deaveraging must be prevented, and tariff compliance certification should be required (i.e., rates in all parts of the state should be within a required range, such as 5%.) Credit terms, including compliance with the Equal Credit Opportunity Act and Fair Credit Reporting Act, must be required, and a provider of last resort, or default provider, should be mandated at fair and reasonable rates for all customers.

Alternative 2.2.3.1 PRO:

1. Current California statute requires nondiscriminatory pricing for electric service. There are reasons to suspect that unscrupulous operators will attempt to abuse some customers as has been the case in tele-communication deregulation.

2. Electric service, as a necessary commodity, must be available universally and equitably. Electric service is among the few necessary commodities, e.g. housing, water, basic foodstuffs, necessary for persons to participate in society. And, because electricity is a prerequisite for participating in the increasingly necessary information services sector, electricity must be affordable so that citizens can remain part of the nascent information network.

Alternative 2.2.3.1 CON:

1. Not all service choices need be affordable to all customers in a deregulated industry. For example, improved levels of service quality may be valued more highly by some customers than others. Those who value it highly should be willing to pay the premiums to offset costs retailers incur to provide it. Those who value it less should make purchase decisions not by comparing their expected value to a regulated, subsidized price created especially for them, but by comparing the value they will get to the true cost of service. For them, that cost of service may not be affordable. Instead, they should choose other alternatives which may be basic, regulated electric service.

2. Protecting against discrimination is sufficient to address "fair dealing" issues. Creating a new regulatory framework to establish acceptable bounds for competitive market prices will hamper the creation of new products and services, and limit the success of deregulation. The Commission should not establish policies that create barriers to the introduction of new and creative ideas. Instead, policies should be developed to monitor market activities, and implement strong corrective actions where retailers have acted against the Commission's express written conditions of market participation. The additional suggested language addressing discriminatory practices is therefore redundant, unnecessary, or overly burdensome for a competitive market.

2.2.4. Right to Redress

Regulatory oversight must continue to ensure that there is a neutral, prompt, no cost or low-cost and effective forum for receiving customer complaints against electricity providers.

2.2.4.1 ALTERNATIVE: Suggested Interpretation

The forum must be no cost, allow for instituting investigations where warranted, and provide complaint resolution and redress for all customers, including those from limited and non-English speaking communities. Regulatory powers must include enforcement, oversight and levying of penalties. Regulatory agencies must be able to suspend or revoke a provider's CPCN or license, and to impose monetary sanctions and full restitution to consumers, including penalties being paid into a fund for consumer education. Consumers must have the right to petition for enforcement actions. Pending resolution of Commission investigations against providers charged with slamming or defrauding large numbers of customers, the Commission may order the provider to post a bond sufficient to satisfy any likely judgment where the provider's place of incorporation or association is outside California or where there is evidence of fiscal instability.

Alternative 2.2.4.1 PRO:

1. The competitive market will not develop equitably or quickly unless there is a continuing regulatory presence. Regulators must support their commitment to a robust competitive market with oversight to ensure that complaints are addressed, abuses are prevented and barriers to entry

are minimized. Without enforcement power and adequate staff, effective enforcement will not be practical.

2. Rapidly escalating complaints of fraud and slamming in telecommunications in California since telephone deregulation have highlighted the necessity for effective and meaningful mechanisms for prompt, no cost consumer redress to be built in to any electric deregulation model. Both Pacific Bell and the CPUC's Safety and Enforcement report enormous increases in customer complaints, particularly with small, out-of-state newcomers to the market. Reputable companies should support consumer redress and protections which will discourage "quick buck" artists and fly-by-night scam operations from coming to California for ill-gotten profits.

3. While the CPUC appears to be the best entity to provide such consumer protections, augmented staffing and resources would be necessary to provide prompt investigation and resolution for California customers. Existing statutory language provides for significant penalties (P.U. Code section 2107), but there may be the need for specific statutory language analogous to the anti-slamming language of section 2889.5 for telecommunications carriers.

Alternative 2.2.4.1 CON:

1. Instituting a no cost forum for redress will over burden the system with malicious and mischievous complaints against retailers and UDCs. The Commission should want to avoid creating that environment to the detriment of fulfilling the balance of its responsibilities. Instead, a low-cost forum should be used. Customers who cannot afford the low-cost forum should be provided with redress at no cost, once they prove to an assigned Commission representative both (a) that they have a complaint which is not mischievous nor malicious, and (b) that they are not able to afford the normal forum costs.

2. These implementation suggestions would be very costly, and would suggest a major increase in the consumer protection activities of the CPUC and/or other government agencies.

2.2.5. Customer Participation in Industry Oversight

Customers must be able to participate in regulatory oversight of the restructured industry, which should be on-going during and after competition commences.

2.2.5.1 ALTERNATIVE: Suggested Extension

Participation should include the above specified right to petition the Commission for redress.

Alternative 2.2.5.1 PRO:

In order for regulators to establish policy and monitor the emerging electric marketplace, it must have continued input from organized consumers. This input should be solicited and should be on-going throughout the oversight period.

Alternative 2.2.5.1 CON:

Since the Right to Redress has already been addressed, it is redundant to include it here. To add clarity and simplicity to all principles, redundancy should be avoided.

2.2.6. Right to Privacy

Consumers should be able to control release and use of sensitive personal information and records. Marketing should not be unduly intrusive.

2.2.6.1 ALTERNATIVE: Suggested Interpretation

The qualifier "sensitive" should be construed liberally as a means to ensure protection of privacy. Further, this information in question should have limited distribution to UDCs, their affiliates, and qualified energy service retailers for marketing and delivery of electricity services. It should not be resold to other businesses for competitive, marketing purposes.

Alternative 2.2.6.1 PRO:

1. California state law places protection of personal information at a higher level than most other state or the Federal law. The emergence of competition in the telecommunications market has imposed significant privacy intrusions upon the California citizenry. Electric deregulation should guard against similar intrusions by placing release and use of personal information squarely in the hands of the customers, not the market competitors.

2. The information that the market will need to promote competition can be made available to competitors at low cost and in an aggregated form so that individual consumers cannot be revealed. Also, government can play a useful role of getting necessary information to the market so that competition can flourish while still preserving the privacy rights of Californians.

3. Customer information should be made available only to a limited set of qualified competitive parties. Perhaps businesses must be certified to be eligible to receive it. Violations of limited usage may be grounds for decertification.

Alternative 2.2.6.1 CON:

Resolution of the information access issue balances facilitating competition and minimizing transactions costs versus personal privacy. This topic is so crucial it has its own chapter 7 with a detailed discussion.

2.2.7 Quality of Service

All choices offered to customers must meet minimum safety and service criteria, and advertized terms and conditions.

2.2.7.1 ALTERNATIVE: Suggested Interpretation

Service must be safe and in accord with specified service criteria. Customers should be offered a choice of differentiated levels of service. Service limiters should not be imposed upon low-income customers.

Alternative 2.2.7.1 PRO:

1. Quality of service must be maintained at current levels to ensure that the expected price reductions from competition represent improved value to consumers. Also, the emergent information services upon which society increasingly relies requires high quality and reliable electric service. However, not all customers demand high reliability, so differentiated service levels should be made available. Those customers must knowingly choose among those different levels.

2. The use of service limiters or other technologies that ration service may not be imposed upon any customers as a precondition for providing service.

Alternative 2.2.7.1 CON:

1. Prevention of discrimination is addressed in the "Fair Dealing" principle and need not be added here.

2. The role of service limiters should be addressed in the context of mechanisms to achieve "Universal Access" and not tied to quality of service.

2.2.7.2 ALTERNATIVE: Suggested Interpretation

Competitive supply of generation services is the first of a series of changes in which bundled electricity will be unbundled and the service components offered to customers in degrees of quality and quantity from which the customer makes a choice of differentiated levels of service. To assure that this consumer choice paradigm operates, service providers must delivered the quality of service that they promised. Holding providers to their advertized terms and conditions of service is essential to ensure that a market based on trustworthy information can flourish.

Alternative 2.2.7.2 PRO:

Quality of service delivered by providers must closely match that which was advertized. Regulatory agencies should ensure that marketing information is accurate. Consumers can ultimately learn how to make choices if they are provided accurate, realistic information.

Alternative 2.2.7.2 CON:

Enforcement of this interpretation suggests substantial resources. Many truth in advertizing problems exist in other markets, so these negative aspects of competitive markets can never be fully avoided.

2.2.8. Required Codes of Conduct and Oversight

All providers must meet minimum standards for certification or registration as a condition of entry.

2.2.8.1 ALTERNATIVE: Suggested Interpretation

As a condition of registration and continued service rights, all providers must either accept an industry standard code of conduct or offer a comparable alternative code specifying standards upon which their customer service policies and business practices will be based.

Alternative 2.2.8.1 PRO:

In the emerging energy services market, the expectations and responsibilities of providers and retail customers will be poorly defined absent some establishment of "game" rules by policy makers. Rather than establishing specific rules for all possible transaction scenarios and potential problems, the Commission should require adoption of a minimum code of conduct as a precondition for registration. These codes can serve as a basis for service design, for customer service practices and for regulatory oversight of those practices.

Alternative 2.2.8.1 CON:

An industry standard code of conduct is likely to be too weak and difficult to enforce. Stronger controls over businesses are likely to be required, as can be seen from tele-communication "slamming" practices.

2.2.8.2 ALTERNATIVE: Suggested Interpretation

All market providers must meet minimum fiscal responsibility standards or provide a bond, and top management and officers must disclose to the CPUC and keep updated at all times: (1) their legal name(s); (2) business address; (3) state where incorporated or associated, including the date of organization; (4) articles of incorporation or association; (5) the name, title and address of each officer and director; (6) name, title, and telephone number of customer contact personnel; (7) name, title, and telephone number of the regulatory contact person; (8) brief description of the nature of the business being conducted in California; and (9) disclosure of any past civil or criminal actions taken against the company or any officer or director of the company for illegal acts related to the operation of the business in the past ten years in any state or federal jurisdiction.

Alternative 2.2.8.2 PRO:

These details are necessary to pursue actions against companies and to provide an awareness on the part of companies that the CPUC is prepared to take action against the company or its officers if warranted.

Alternative 2.2.8.2 CON:

1. These details provide a basis for taking regulatory or legal action should they become necessary, but they do not instill in the company a positive incentive to do right.

2. Industry codes of conduct can be used in conjunction with "Better Business Bureau" methods of providing information to customers about whether companies adhere to such codes of conduct, whether actions have been taken against them, and the nature of dispute resolution available.

2.2.9 Right to Universal Electric Service

Electricity is a universal service which government must ensure is accessible to all residents of California.

2.2.9.1 ALTERNATIVE: Suggested Interpretation

Because electricity is a necessary service, electric restructuring must result in no significant cost increases for any identifiable group of customers. To the extent that savings result from the restructured market, customer classes with relatively fewer options should still reap comparable savings to those with more options.

Alternative 2.2.9.1 PRO:

As a necessary commodity, the price and availability of electricity will prove to be primary focal points for policy makers. The premise of restructuring is to bring lower prices through market-based efficiencies. However, customer classes with fewer options (which

represent the majority of electricity users) will lose the market leverage that they enjoyed as monopoly-aggregated customers. Thus, a goal of restructuring must be to bring market efficiencies to those customers who are likely to be overlooked by the competitive market. Otherwise, restructuring will result simply in windfall price reductions for a select number of large electric consumers at the expense of the majority of Californians.

Alternative 2.2.9.1 CON:

1. Electric restructuring may result in cost reductions to some customers, and perhaps cost increases to others. Those who have traditionally been subsidized through price averaging will see bill increases as lower cost customers drop off the UDC full service system.

2. It is unrealistic to discuss "price" of electricity since CPUC policy decisions divide electricity service costs into segments which cannot be readily reassembled and discussed in terms of "price." Taking D.95-12-063 literally requires UDCs to separately itemize on the bill PX energy from distribution services even for full service UDC customers.

3. Adopting this proposed principle will tie the hands of the Commission either by (a) significantly reducing the list of good policy alternatives available to the Commission to enact restructuring; or (b) placing a huge financial burden on the utilities to subsidize remaining full service customers, thereby undermining the financial integrity of the California electricity industry. The Commission must therefore determine in advance whether or not it wishes to protect the status quo for those few customers who have been heretofore greatly subsidized by all others. That decision will significantly impact all other decisions.

2.2.9.2 ALTERNATIVE: Suggested Interpretation

Government is responsible to design programs that can provide universal access to electricity services for those whose income or personal circumstances make market participation alone a hardship.

Alternative 2.2.9.2 PRO:

1. Separation of integrated utilities into distinct entities probably requires customers to pay identifiable amounts for generation, distribution services, and other authorized expenses collected by UDCs. It is possible that the traditional approaches of baseline rates and supplemental usage allowances with minor income assistance programs are unworkable in the structure of the industry.

2. Direct cost subsidy programs may be a more workable approach to ensure universal access to necessary electricity services, whether energy or connection to the distribution system.

3. Government should be responsible for this universal access, not electricity ratepayers.

Alternative 2.2.9.2 CON:

It may be theoretically preferable to have general taxes support universal access, but government revenues are extremely limited.

2.2.10 Transaction Costs

Market processes should be designed to avoid unnecessary transaction costs. Regulatory policy should be focused upon lowering barriers for market entry by new firms and to intelligent consumer choice.

2.2.10.1 ALTERNATIVE: Suggested Interpretation

Market processes should be designed to avoid unnecessary transaction costs. Regulatory policy should be focused upon lowering barriers for market entry. Essential elements of electric service should be non-proprietary and customers without or with modest market choice should be responsible for no more than an equitable share of costs arising from restructuring.

Alternative 2.2.10.1 PRO:

Transaction costs, or the avoidance of them, will prove to be a determining factor in whether competition develops for the majority of California consumers. They represent a market barrier that could undo regulatory efforts to promote competition. Where transaction costs are incurred for anything other than promoting market information, protecting customer privacy, or preserving social equity objectives, then they should be discouraged by the Commission. Discouraging proprietary systems and guarding against interclass cross-subsidies are important means of limiting unwarranted transaction costs.

Alternative 2.2.10.1 CON:

None yet identified.

2.2.10.2 ALTERNATIVE: Suggested Interpretation

The complexities of the restructured electricity industry will place major burdens on consumers which requires that they obtain and assimilate general background information about "new" products and services, as well as make specific decisions. All of this contributes to socalled transactions costs, and really cannot be avoided. What can and should be avoided is the further step of evaluating the merits of the information itself. Is it accurate? Is it complete? Regulatory policy and enforcement action should be designed to ensure that consumers have market information which is trustworthy, so that the transactions cost burden is not expanded

unnecessarily. Accuracy of information should be ensured by a standard of veracity. Marketers and other market participants that violate accuracy standards should be punished severely.

Alternative 2.2.10.2 PRO:

1. Trust is difficult to obtain, and mistrust in one perpetrator can be readily extended to other market participants, even when unwarranted. The loss of trust will reduce market participation and reduce benefits of competitive choice.

2. Regulatory agencies should be visible in asserting that market information is trustworthy.

Alternative 2.2.10.2 CON:

1. Developing complete and accurate information about market offerings will be difficult and must be repeated frequently. This will cause it to be expensive.

2. Innate skepticism leads many to a laissez-faire attitude, which will be hard to overcome.

2.3 Design of Strategic Market Transformation

The CPUC's existing policy decisions move California from regional, centrally planned electricity systems with integrated utilities to a set of three entities segmented by function (generation, transmission, and distribution). Generation is to be a competitive market, while transmission operation and distribution remain monopolies under FERC and CPUC regulation, respectively. The large integrated utility of California's past and present will not exist in the future. Direct access, of course, fragments the monopoly distribution function by permitting direct sales of generation services to retail, end-use consumers. In addition, the CPUC has directed the investigation of further unbundling of the distribution function and reliance upon competitive forces for even more of its component services. All of these actions contribute to a market transformation toward a consumer choice paradigm. Many of the details of this transformation remain unclear, and while this report attempts to contribute to greater clarity, there are many steps yet to travel.

This section briefly outlines something of the appropriate market transformation strategies, and the appropriate institutions, that will both be required to achieve the objective of a fundamental transformation of the market.

2.3.1 Market Transformation Strategies

An overt market transformation strategy must be developed and implemented in order for this fundamental change in the planning and delivery of services to be successful. This change can be simply viewed as one of moving from use of more centralized resource decision making, made on

customer's behalf by utilities and regulators, to decentralized decisions based upon individual consumer choices. This change requires a well functioning market that permits customers to make "meaningful choices" from among reasonable alternatives. Absent such a strategy, the CPUC risks customer confusion, poor market information, disparate choice, disproportionate market power, and political backlash resulting from an undeveloped and poorly performing competitive market.

Since consumer choice is the paradigm denoting these new markets and additional ones, the market transformation strategy should be oriented to consumer empowerment and achieving workable competition in various market segments. In order to provide the market transformation necessary to achieve workable competition it is generally believed that consumers must have "meaningful choice" from among competitive market options. Meaningful choice is the potential to achieve significant improvements in value received from expenditures made, by permitting individual customers to select from market options with quantity or quality differences.

Three primary aspects of a market transformation strategy that need to be assessed and effectively implemented include:

a. Reduction of transaction costs of participation in markets by developing standardized terms and conditions of service options, by facilitating comparison of choices, by developing conditions conducive to the provision of trustworthy market information, and by developing mechanisms in which small customers can pool their demands into more effective blocks to offset the enormous size range among electricity consumers.

b. Institutionalizing customer education processes and transitional programs that assist in reducing market barriers and that facilitate development of an understanding of the procurement of unbundled energy services.

c. Consumer protection programs to resolve disputes and provide redress for systematic problems that develop.

Each of these three areas will be addressed in a separate chapter later in this report. (Chapters 10, 11, and 12).

2.3.2 A Market Transformation Institution

The CPUC has identified the need for monitoring the progress of direct access programs. If they are originally designed to be phased, market success (or failure) may be an important indicator that further phasing should proceed on track (or be slowed down). The CPUC should realize that further changes in the structure of the market, such as distribution function unbundling, will

require a more comprehensive oversight and monitoring function by government. Rather than periodic authorization of rates, with some scrutiny of costs and proposed expenditures, government may need to design new activities that permit it to gauge the successes and failures of market structures and assess options and merits of "tweakings" of the market rules to achieve improved market performance, make consumer choice more meaningful, and increase incremental improvements of societal economic efficiency.

An initial description of a market monitoring effort required to transform from the current integrated utilities into the three functional entities with direct access for generation services is addressed in the final chapter of this report. Beyond these limited observations, the further steps required to create both a market transformation strategy as well as the oversight institution(s) required to make it happen remain to be determined in another forum.

Chapter 3. ISO/PX/Schedule Coordinator

This section provides an overview of the market model for California's restructured electric services industry. It defines the market participants in the new industry structure, describes their roles and responsibilities, and discusses the interactions that will occur among them. The categorizations and descriptions of market participants are intended as a nomenclature to facilitate the discussion of market rules and other issues. This section is not intended to provide an exhaustive and precise listing of all the potential activities and entities that may participate in the new industry structure, nor to provide detailed descriptions of the protocols that will govern interactions among these market participants. Rather, the purpose is to provide a general description of the market model as a foundation for considering the many issues addressed elsewhere in this report.

Near the end of the WEPEX discussions leading to the FERC filing, the group determined the need for a functional position different and distinct from the Independent System Operator, (ISO), that would, in concept, relieve the ISO from the burden of executing all the millions of potential transactions related to scheduling, settlements, and billing tasks entirely on its own.

WEPEX identified the need for the position, and defined its basic obligations, i.e. submission of balanced schedules and responsibility for whole loads and generators. The details of the position were left for further development. One purpose of this chapter is to provide a description of the position and its responsibilities within the context of the Direct Access environment.

Any existing Schedule Coordinator / ISO Protocols were developed by WEPEX, are subject to FERC jurisdiction, and therefore could be altered by FERC actions. The DAWG has not provided pros and cons for most of this section. We would submit that any inquiries regarding this section should be directed to WEPEX.

3.1 Marketplace Functions of the Independent System Operator (ISO)

The ISO will be a non-profit California corporation regulated by FERC, that will provide open, non-discriminatory services and access to the transmission grid for all users of the system.

The ISO receives schedules, monitors control area operations and communicates status of each to all market participants except customers.

The ISO is responsible to provide Schedule Coordinators with grid information, including conditions that impact routing, any accepted schedules and prices on a daily by hour basis, and any specific operating instructions for the day ahead. The ISO will also provide settlement

information to the Schedule Coordinator for imbalances, transmission congestion, and ancillary services.

The ISO receives preferred schedules and any required meter data from Schedule Coordinators. (Please see 3.6 for additional detail).

The ISO provides Transmission System Information and Communication, as well as Transmission Access and Pricing to Generators, Aggregators, and Retailers. (Please refer to the FERC filing of 4/29/96 for a complete description of the ISO).

3.2 The Power Exchange

The Power Exchange will establish a competitive spot market for electric power through a day-ahead and hour-ahead auction of generation and demand bids using transparent rules and protocols. This auction will bring together buyers and sellers who have not arranged all of their needs through bilateral contracts. This auction will also allow the Power Exchange to reveal day-ahead and hour-ahead market-clearing prices in coordination with the ISO.

The Power Exchange in the Direct Access context, will act as a Schedule Coordinator, with the ability to handle more transactions in greater numbers than those outside the Power Exchange, including settlement and billing functions.

(Refer to Section 4.6 "Role of the Schedule Coordinator," for the list of Schedule Coordinator responsibilities, and refer to the FERC filing of 4/29/96 for a complete description of the Power Exchange.)

3.3 The UDC

Each Utility Distribution Company (UDC) will continue to provide regulated distribution services to customers. They will design, construct, own, operate, and maintain the distribution assets necessary to ensure safe and reliable delivery of electric energy to all customers connected to the distribution system.

The UDC's will be responsible for connecting new customers to the distribution system, restoring service in the event outages result from storms and other occurrences, and turning off services for customers that relocate or fail to comply with CPUC approved credit and collections policies yet to be determined.

UDC's may own and operate their own generating facilities, bidding their generation into the Power Exchange during the first 5 years of the new market structure.

Each UDC may become a provider of choice for hourly meter data for Direct Access customers, as required for Schedule Coordinators and Retailers. Each UDC may become a provider for the collection of payments for Transmission and Distribution, access fees, as well as Competition Transition Charges.

Each UDC will act as a retailer as customers choose them or become the provider of last resort / default by relying on the Power Exchange as their provider.

Each UDC will schedule "must take" resources with the ISO.

3.4 Aggregators, Marketers/Retailers, Brokers, Generators, Ancillary Service Providers

The DAWG is not prescribing, and WEPEX will not prescribe rules and definitions for new market participants, unless specific requirements are determined to be necessary and are approved by regulators. What follows are illustrative definitions of potential new market participants. Schedule Coordinators will establish their own requirements for these market participants who wish to use their services.

3.4.1 Aggregators

Aggregators (including UDCs) will provide Unit Commitments, hourly schedule at each injection point, and bids for ancillary services, and congestion management to Schedule Coordinators. They will gather required meter information for Schedule Coordinators and Transmission Owners. They will also settle with Schedule Coordinators for imbalances and ancillary services, settle with other Aggregators, Marketers, and Brokers for energy, and settle with Generators for energy, imbalances, and ancillary services. They will respond to instructions or requests from the Schedule Coordinators for generation schedule changes, and may elect to arrange trades or sales with Marketers, other Aggregators, and Traders. They may also elect to act as Generators, Marketers and Customers. Each UDC will perform as a regulated supply aggregator for utility-owned generation and purchased power.

3.4.2 Marketers/Retailers

Marketers/Retailers will provide hourly aggregate load schedule forecast at each delivery point and demand curtailment bids, settle with Schedule Coordinators for imbalances and ancillary services, settle with Aggregators, other Marketers/Retailers, and Brokers for energy, and settle with customers for energy and all other charges. Marketers/Retailers will respond to instructions or requests from the Schedule Coordinators for changed load, curtailments and may elect to arrange trades or purchases with other Marketers/Retailers, Aggregators, Schedule Coordinators, and Traders. Marketers/Retailers will gather required meter information for Schedule

Coordinators and UDC. Marketers/Retailers may elect to act as Generators, Aggregators and Customers.

3.4.3 Brokers

Brokers will be allowed to arrange and settle financial transactions between Aggregators, Marketers, and other Brokers.

3.4.4 Generators

Generators will produce power, provide supply information and Generation Schedules to ISO and Aggregators, receive payment for energy and ancillary services, settle for imbalances, receive Operating Instructions from ISO and/or Aggregators, and provide required meter data to Aggregators.

3.4.5 Ancillary Service Providers

Ancillary Service Providers will include but not be limited to the ISO, Generators, Schedule Coordinators, Marketers, and Aggregators. Ancillary Service Providers will provide services that include but need not be limited to: Spinning Reserve, Non-Spinning Generation Reserve, Interruptible Load, Regulation, Replacement Reserves, Reactive Power and Voltage Control, and Black Start Capability.

3.5. The Schedule Coordinator (SC)

3.5.1 What is a Schedule Coordinator?

A Schedule Coordinator is an individual/group/partnership/corporation that accepts responsibility to interface with the ISO on behalf of Retailers, Aggregators, Customers/Consumers, Generators, Other Schedule Coordinators, and The Power Exchange. Schedule Coordinators should not be restricted or confined to a separate class of market participants; the function may be performed by other market participants.

The Schedule Coordinator will submit preferred balanced schedules to the ISO on an hour-ahead, day-ahead, same day basis. The Schedule Coordinator will provide only the required hourly metered data to the ISO. The Schedule Coordinator will be required to obtain grid information from the ISO, receive accepted schedules and prices from ISO, as well as on-going operating instructions from the ISO to pass on to clients / end-users.

The Schedule Coordinator will settle with the ISO for imbalances (deviations in generation and/or load), charges for ancillary services not self-provided, and charges for the use of congested transmission facilities.

The Schedule Coordinator will settle with Aggregators, Retailers, other Schedule Coordinators and Traders for imbalances, charges for ancillary services not self-provided, charges for the use of congested transmission facilities, and contracted energy.

The Schedule Coordinator provides bids to the ISO for congestion management and ancillary services, including demand curtailment, responds to ISO requests for changes in generation and load, pursuant to ancillary service bids or system reliability reasons, and issues billings and payments as needed to the ISO.

The Schedule Coordinator must be available on a 24-hour, 365 days a year basis to perform these functions.

3.5.2 What are the requirements to be a Schedule Coordinator?

3.5.2.1 Certification / Authorization to Perform

All Schedule Coordinators will be required to meet the objective, performance-based criteria adopted by the FERC. Such performance-based criteria may include the requirements to meet adopted communication protocols, satisfy creditworthiness standards, and abide by FERC approved ISO operating protocols. The ISO may be authorized by the FERC to review and approve Schedule Coordinator applications for certification. Applicants for Schedule Coordinator certification may petition FERC for review of ISO certification denial or revocation.

3.5.2.2 Limitations on the number of Schedule Coordinators

3.5.2.2.1 ALTERNATIVE

There should be no artificial or regulatory limitation on the number of Schedule Coordinators; the number will be determined by the marketplace.

3.5.2.2.2 ALTERNATIVE

WEPEX's proposal recommends a limitation by definition, in that Schedule Coordinators must represent the total load of one end user and/or the entire output of one generator.

Alternative 3.5.2.2.2 PRO

This is a technical limitation only, in that there could be as many Schedule Coordinators as there are end-users. If partial load scheduling is to be allowed, then settlement responsibility must be clearly defined and allocated.

Alternative 3.5.2.2.2 CON

This limitation would prevent customers from opting to have Schedule Coordinators schedule only part of their loads.

3.5.2.2.3 ALTERNATIVE

The number of certified Schedule Coordinators will be limited only if required to accommodate technical ISO limitations.

3.5.2.2.4 ALTERNATIVE

Limit the number Schedule Coordinators to be certified by the ISO. This may be reasonable if the ISO/Schedule Coordinator interface is made more efficient by such a restriction. These certificates could be made transferable to encourage an auction to the highest valued user.

3.5.3 What Information does a Scheduling Coordinator Provide to the ISO?

3.5.3.1 Preferred Schedules

The ISO needs to know the quantity of energy that is scheduled to be withdrawn from the transmission grid by location, the quantity of energy that is scheduled to be injected into the grid at each location, and the price bids associated with energy and ancillary services. It is not the scheduled coordinators responsibility to do load forecasts, but to submit balance to schedules. Price bids to the ISO are binding and may not be changed during the day-ahead scheduling process.

The Schedule Coordinator will provide aggregated data to the ISO sufficient for the ISO to compute imbalances, and not provide individual customer data except in support of auditing the Scheduling Coordinator's performance.

The Schedule Coordinator will provide this information on an hour-ahead/day-ahead basis.

3.5.3.2 Meter Data

The Schedule Coordinator will provide any required meter data for its load and supplies, in the standard format protocols to be transferred to the ISO for its loads that support actual usage; this information will then be used in the settlement process.

The Schedule Coordinator will provide aggregated data to the ISO sufficient for the ISO to compute imbalances, and not provide individual customer data except in support of auditing the Scheduling Coordinator's performance.

3.5.4 What Information does the ISO provide to the Schedule Coordinator?

3.5.4.1 Grid Information

On a day-ahead basis, the ISO will inform the Schedule Coordinator of system operating conditions for the next operating day that include potentially congested transmission paths based on current day system conditions, scheduled line outages for the following day, forecasted hourly major loop unscheduled flow over ISO inter-zone interfaces and connections, potential over-generation conditions, an hourly forecast of expected total load, and the ISO's hourly requirements for reserve and regulation ancillary services, expressed as a percentage of load.

3.5.4.2 Accepted Schedules and Prices

On a day-ahead basis, the ISO will transfer final accepted schedules into the settlement system. Accepted schedules will be consolidated into operating schedules to be transferred to the Real-Time Dispatch System, to be accessed by the Schedule Coordinator.

3.5.4.3 Operating Instructions

The accepted schedules will then be consolidated into operating schedules, and combined with other generation control information. This information will be transferred into the Real-Time Dispatch System, to be accessed by the Schedule Coordinator. The ISO will identify the need for and the total amount of over-generation mitigation necessary; which occurs before preferred schedules are submitted, and will direct each Schedule Coordinator to reduce their schedules according to the approved protocols.

3.5.4.4 Accessability to ISO information

The Schedule Coordinator must have access to its own data and that of it's clients. However, the Schedule Coordinator must not be allowed to access data not its own, or data of those it does not represent through standard ISO protocols.

Examples of the kinds of data to have restrictive access are: schedules, settlement information, metering data, and billing and payment information.

3.5.4.5 Settlement Information

3.5.4.5.1 Imbalances

Schedule Coordinators may continue to revise their day-ahead schedules subject to ISO approval, bearing the economic consequences associated with the deviation from their day-ahead schedules. Whenever the committed schedules are changed as a result of the hour-ahead scheduling system, the last committed schedules will be transferred to the Settlement system. The ISO will provide information to the Scheduling Coordinator that will become the basis for the settlement process, which will be based on variations between the committed schedule and the actual usage.

This information will consist of aggregated imbalances for the entire set of loads submitted by the Scheduling Coordinator for each T/D interface node, which will be used by the Scheduling Coordinator to allocate imbalance settlement costs to each of its customers.

Variations to the committed schedules will result in economic consequences based on the hour-ahead, day-ahead and real-time balanced market pricing established by the ISO for the day of the committed schedule. The Schedule Coordinator will be responsible for initial payments for imbalances, and billing its own customers for imbalances in turn.

3.5.4.5.2 Transmission Congestion

If there is no congestion, then the ISO will inform all Schedule Coordinators that their preferred day-ahead schedules for energy have been accepted. If there is congestion, then the ISO will use the price bids provided by the PX and Schedule Coordinators to determine an advisory re-dispatch to eliminate potential congestion at least cost.

The ISO will then provide Advisory Re-Dispatch Schedules, estimated transmission congestion prices charged to all power flows across congested interfaces, ancillary services pricing, and updated estimated transmission loss factors, to Schedule Coordinators.

Schedule Coordinators may adjust their Preferred Schedules in response to the ISO's advisory re-dispatch, and obtain final pricing for the use of congested interfaces. The resulting final schedules and pricing will be provided to the Schedule Coordinators.

3.5.4.5.3 Ancillary Services

The ISO provides and communicates pricing for ancillary services not self-provided.

3.5.5 What are the Hardware and Software Requirements for Schedule Coordinators to Communicate with the ISO?

3.5.5.1 Background

The ISO is obligated under FERC's Open Access Order to operate an Open Access Transmission System (OASIS), to post its transmission services and tariff information, and to provide market information to all market participants. The ISO will operate an Electronic Information Network (as distinct from OASIS) that allows Public Access to its data. A transmission operator is required to post available transmission capacity, transmission service products and pricing, ancillary service offerings and prices, transmission service requests and responses, transmission facility status, transmission service schedules on an OASIS for public access via the Internet.

The ISO will post market data that will include the ISO's advisory hourly forecast of expected total load, potential over-generation conditions, forecasted hourly major loop unscheduled flow over the ISO's power grid, the ISO's requirements for reserve and regulation ancillary services, congested transmission ratio information, scheduled transmission outages, and market clearing prices for energy and ancillary services.

3.5.5.2 Specific Hardware / Software Requirements

Please refer to appendix 4.a for the specific requirements of hardware and software proposed for the Schedule Coordinator’s communication with the ISO.

3.5.6 Information to be Supplied to the Schedule Coordinator from Market Participants

Schedule Coordinators will establish protocols regarding interactions with their own customers (aggregators, retailers, generators, end-users, and other Schedule Coordinators). The DAWG and WEPEX will not prescribe such rules. The following discussion is intended to be illustrative only.

3.5.6.1 Marketers/Retailers and Aggregators

Marketers/Retailers and Aggregators, if separate from a Schedule Coordinator, will provide hourly aggregate load schedules at each delivery point (includes demand curtailment bids), Settle with Schedule Coordinators for imbalances, ancillary services, and congestion, Respond to instructions or requests from Schedule Coordinators for changes in load requirements or curtailments (pursuant to individual agreements), and gather required metered data in standard ISO protocol for Schedule Coordinator.

3.5.6.2 Generators

Generators will provide supply information, and settle for imbalances.

3.5.6.3 Customers

Customers will provide usage data as requested to enable Schedule Coordinator to develop balanced schedules, settle for imbalances and congestion, and pay for energy and other charges, if not paid through retailer/aggregator/UDC/PX.

3.5.6.4 Other Schedule Coordinators

Schedule Coordinators will coordinate schedules with others as necessary, settle with other Schedule Coordinators for imbalances, congestion, and ancillary services, and settle with other Schedule Coordinators for contracted energy.

3.5.7 Information to be Supplied to Market Participants by the Schedule Coordinator

Schedule Coordinators will establish protocols regarding interactions with their own customers (aggregators, retailers, generators, end-users, and other Schedule Coordinators). The DAWG and WEPEX will not prescribe such rules. The following discussion is intended to be illustrative only.

3.5.7.1 Marketers/Retailers and Aggregators

Marketers/Retailers and Aggregators will receive communication of preferred and Committed load schedules at each delivery point (includes demand curtailment bids), billing for imbalances, ancillary services, and congestion, instructions or requests for changes in load requirements, or curtailments, and confirmation of metered data received to forecast load requirements.

3.5.7.2 Generators

Generators will receive settlement information for imbalances, payment for energy and ancillary services.

3.5.7.3 Customers

Customers acting as their own Schedule Coordinators will receive settlement information if not provided by retailer/aggregator/UDC/PX, and billing for services if not provided by retailer/aggregator/UDC/PX.

3.5.7.4 Other Schedule Coordinators

Schedule Coordinators will coordinate schedules with each other as necessary, and will settle with other Schedule Coordinators for imbalances, congestion, and ancillary services, and settle with other Schedule Coordinators for contracted energy.

3.5.8 Interaction Among Schedule Coordinators

The Role of the Power Exchange (PX) will be identical to the role of other Schedule Coordinators in Direct Access, except as market forces dictate that they manage "batches" of schedules for multiple clients in greater numbers.

There must be no competitive advantage for Power Exchange vs. Direct Access Schedule Coordinators.

The customer should have the option of by-passing a Schedule Coordinator if they elect to purchase power from the Power Exchange, using the PX as the Schedule Coordinator.

3.6 Direct Access Customers Choices of a Schedule Coordinator

This section addresses the issues and options facing Direct Access customers with respect to the selection of a Scheduling Coordinator. Customers receiving bundled UDC service will obtain their Scheduling Coordinator services through the UDCs interactions with the PX. Direct Access customers will have options for obtaining Schedule Coordinator services, which are described below.

3.6.1 ALTERNATIVE: Direct Access Customer Chooses to Be Its Own Scheduling Coordinator.

As with all Scheduling Coordinators, Direct Access customers choosing to act as their own Scheduling Coordinator are required to be certified by the ISO. The ISO certification standards will be designed to ensure that Scheduling Coordinators meet certain technical requirements relating to communications, data, and metering standards, and also meet credit-related requirements that demonstrate financial capability to settle transactions with the ISO.

Alternative 3.6.1 PRO

1. Provides customer with direct interface with ISO;
2. Avoids third-party fees for scheduling service; and
3. No exposure to operational or financial problems arising from poor performance by other Scheduling Coordinators.

Alternative 3.6.1 CON

1. Requires computer and communications systems to interface with the ISO;
2. Requires trained staff to follow ISO protocols for scheduling, settlements and billing; staff must also be trained to interface with other Scheduling Coordinators; and
3. Staff requirements involve operating 24 hour/per day, 365 days per year.

3.6.2 ALTERNATIVE: Direct Access Customer Selects a Scheduling Coordinator Certified by the ISO

In this alternative, the Direct Access customer executes a contract authoring its Scheduling Coordinator to submit schedules to the ISO, to send meter data to the ISO, and to settle with the ISO on its behalf. These contracts will be developed under free market conditions and will not be subject to regulatory oversight, except with respect to the possible application of consumer protection codes.

Alternative 3.6.2. PRO

1. Eliminates cost and management issues associated with computer, communication systems, and expert staff to interact with the ISO and other Scheduling Coordinators.
2. Potential cost savings associated with out-sourcing Scheduling Coordinator needs.

Alternative 3.6.2 CON

1. Requires delegation of significant operational and financial responsibility to third party.
2. Potential exposure to consequences of poor performance by the Scheduling Coordinator.
3. Some risk of being exposed to fraudulent behavior.

3.7 Inter-relationships and information flow among market participants

Please review the attached charts 3.A through 3.E for a flow chart representation of the relationships among market participants.

Appendix 3.a

3.a.1 Architectural Requirements for the OASIS Node

3.a.1.1 Internet Compatibility All OASIS Nodes shall support the use of Internet tools, Internet directory services, Internet communication protocols, connection of OASIS nodes to the public Internet is required within connections to be secured. OASIS nodes will support private connections to any user who requests such a connection, and is willing to pay connection costs.

3.a.1.2 Communication Standards will be established for dial-up connections Point to Point, Serial Line Internet Protocol, Internet Protocol Control Protocol. Network connections will allow Transport Control Protocol and Internet Protocol.

3.a.1.3 Internet Tools such as World Wide Web browsers, Hypertext Markup Language (HTML), HTML Forms, Simple Network Management Protocol, E-Mail, should be utilized.

3.a.2 Hardware/Software Requirements for the Scheduling System

Interface options for the PX and other Schedule Coordinators will be identical. Operating Platforms will include, but not be limited to PC's running Microsoft Windows, MAC, and Unix. Proprietary hardware/software must not be allowed consideration. Highest speed communications systems available should be utilized.

3.a.3. How the Schedule Coordinator will use the Hardware and Software Systems

To enter and modify schedules manually, import/export entire sets of schedules from and to other sources, review schedules and associated memory, retrieve previously submitted schedules, print schedules, validate schedules locally, submit schedules to the ISO, and review public market data on the ISO EIN.

Chapter 4. Phase-In of Eligibility

This chapter focuses on the issue of a phase-in schedule for direct access eligibility. The topic of a phase-in schedule has been one of the most contentious issues in the DAWG discussions. Some parties are of the belief that no phase-in period is required and that all customers should be eligible for direct access beginning January 1, 1998. Other parties believe that a phase-in period is critical to the success of direct access and should be defined by the schedule proposed in CPUC D.95-12-063.

The discussion that follows identifies the rationales behind the different opinions of parties regarding the question of a phase-in period, and defines some alternatives for addressing this issue. Chapter 5 further elaborates on the design of a phase-in program, which becomes relevant once a decision has been reached by the CPUC on the basic issues raised below.

4.1 Perspectives Among Parties Concerning the UDC

There is considerable dispute among the parties about the technical, market success, and equity rationales for limiting eligibility, and thus causing a phased direct access program. A major portion of this dispute can be traced to different views of the responsibilities and obligations of the UDC as it has been defined by the CPUC in D.95-12-063, but which appear to be evolving through D.96-03-022 and the subsequent Assigned Commissioner Rulings (ACR) shaping this DAWG process.

Some parties tend to understand the UDC as D.95-12-063 defined it. The UDC resembles the IOU in being a franchise monopoly for all aspects of the current utility distribution function. This means the UDC installs meters, collects data, prepares bills, and serves customers much like the utility currently does. With this perspective, there is concern that the UDC will have constraints on development and installation of new systems for metering, billing, etc. that are legitimate technical rationales for limiting eligibility.

Other parties, on the other hand, view the UDC as a smaller entity and one that emerges from the distribution function unbundling process sanctioned by D.96-03-022 with a reduced scope for monopoly services. Perhaps other entities will be allowed to provide metering services, billing services, or other aspects of customer service. It is the view of some parties that the difficulties of the single IOU organizations to install advanced metering equipment and billing systems is readily overcome by permitting the emergent energy suppliers to perform these tasks. Particularly with billing, which is seen by some as an essential point of contact with the customer, irrespective of what happens to billing for UDC services, these technical capability development activities are a necessary element of competing for business. Seen from the

viewpoint of many competing organizations performing similar efforts in parallel, there are many fewer technical constraints.

The point of this review is to communicate that what is a legitimate technical concern under one organization of the industry, may not be a legitimate technical concern under a different organization of the industry. Since the CPUC is the regulatory agency that has both defined the UDC and explicitly created a forum in which the UDC might reduce its scope through time, the CPUC must resolve some of these issues of direct access in the context of resolving the nature of the distribution services that will be restricted to the UDC.

4.2 Rationales for a Phase-In Schedule

The CPUC has asked if there are technical and policy reasons for considering limiting eligibility to direct access. Limiting eligibility would result in phased introduction of direct access, such as the five-year 1998 through 2002 phase-in identified in CPUC D.95-12-063 and re-characterized as a slowest possible phase-in schedule in D.96-01-006.

From a technical perspective, it is the intent of the Direct Access Working Group that the new market structure function properly, fairly and efficiently in a timely and reliable fashion. This is also a fundamental requirement for electric consumers. The phase-in disagreements presented in this report relate mainly with the logistics and requirements needed to fulfill this objective, not the objective itself.

This section includes four subsections that provide some conceptual background to understand why parties have different concerns, and to discuss separately three categories of rationales: technical feasibility, market success, and equity of participation.

4.2.1. Overview of Three Types of Rationales

DAWG has identified three types of concerns: technical, market success, and equity. Technical rationales limit the feasibility of introducing direct access any faster because some requirements essential for it cannot be made available except in initially limited capacities, but which can be remedied through time until the entire customer population can be served. As noted above, a technical rationale may exist entirely within a specific organizational form of the industry, but not be a technical rationale for another form of the industry. These technical concerns fall into two distinct groups.

The first involves those technical areas where the constraint can be identified and for the most part quantified. In terms of severity, these tend to present the least amount of anxiety since they are known and their effects understood. These elements will be addressed as areas of concern

involving: (a) data processing capabilities; (b) metering and communication systems; (c) billing systems and (d) integrated system performance.

The second group involves concerns which are much more difficult to identify and assess, not only at the onset, but during the initial and on-going operation. These concerns relate to the continual need to debug, alter, expand, repair and validate the systems, methods, and interfaces employed to facilitate the new market structure, all the while maintaining service quality and reliability. It is difficult to gain an appreciation for these concerns without a thorough understanding of the complexities of the systems required, their functional characteristics, and how they relate with the operational constraints of the unique commodity of electric service.

Additional considerations for limiting eligibility are rationales based on a desire for the market structure to be successful. One can theorize that in an immature industry, the capability to handle the entire customer base successfully might not be fully possible in the first or even second years. These rationales differentiate between things that are feasible, but not desirable, leading to the conclusion that phasing can contribute to a more successful market.

Finally, a third category of rationales for limiting access are ones that address equity concerns. For example, CPUC D.95-12-063 requires that all customers classes benefit from direct access, rather than restricting direct access eligibility to economic sectors or by customer size. Equity concerns have also been identified about providing direct access to single firms in industries with limited competition among otherwise similarly situated firms.

4.2.2 Technical Rationales for Limiting Eligibility

These technical considerations emphasize what is feasible, as opposed to what might be desirable, but both feasibility and desirability are conditional on the perspective of the evaluator.

The hypothesized technical rationales are:

1. *demonstration of integrated system performance* involves determinations that the combination of hardware/software identified above to maintain reliable operation of the electrical system are successfully integrated into new systems that perform to specifications.

2. *data processing capabilities* (of the UDC, scheduling coordinator, ISO, and aggregator) required to compute settlement of ISO imbalance costs in a fair and equitable manner and to store hourly usage and price data for virtual direct access customers will not be in place in sufficient volume to allow unlimited eligibility.

3. *metering and communication systems* essential to provide the information required for settlement and to respond to hourly price signals cannot be installed in sufficient volumes to allow unlimited eligibility.

4. *existing UDC billing systems for small customers* have limited capabilities to handle the computations and bill display requirements of direct access, and new systems will not have sufficient capacity to allow unlimited eligibility in 1998.

4.2.2.1 Demonstration of Integrated System Performance

Integration of separate hardware/software systems into systems demonstrated to work properly has been identified as a concern. Some of the issues fall within the scope of the proposed ISO and PX institutions that WEPEX has filed with FERC. Similar issues affect systems that are the responsibility of the UDC as determined in D.95-12-063. These systems are particularly oriented to information flows that are crucial to forecasting loads, nominating resources, measuring loads, identifying and billing for imbalances and actual usage, and collections/remittances to multiple suppliers.

Particularly with integrated systems in which multiple parties share responsibility, such parties need to: (1) develop a better understanding of the potential data flows between various organizations; (2) understand the technical parameters of these potential data and the communication systems exchanging data, (3) develop an understanding of the hardware specifications to permit this data exchange to occur; (4) identify the decision mechanisms required to ensure that multiple organizations understand and will conform to a standard for data exchange; (5) identify the need for hardware/software shakedowns to ensure data communication works properly.

California is electrically interconnected with many other states and with two other countries. These interconnections, or electrical highways, involve synchronized operations requiring continual coordination, cooperation and resource balancing and monitoring to ensure reliable and quality service. The interconnections have provided huge economic benefits for California and now help provide a gateway for competition. The fact that electricity travels substantially near the speed of light, embodies dual real and reactive personalities, and cannot be stored should not be taken lightly in trying to understand the complexities of providing this service. Several recent events should remind us of instances where moderate problems several states away, or just next door, can translate into millions of Californians losing power.

The existing computerized control systems IOUs and other utilities have installed involve different manufacturers, vintages, and operational metering and communication systems and interfaces. In order for these systems to function properly, requires a considerable amount of handholding, feedback and coordination.

These existing systems have required a substantial amount of time to develop, validate, and enhance to their current state and will form the initial foundation to support the transition to

WEPEX. Each of these systems, in varying degrees, are required to perform numerous operating, dispatch, scheduling and accounting functions. These functions include:

a. Automatic generation control, which balances generation to match schedules and load;
b. Economic dispatch
c. Automated back-up systems;
d. Supervisory control systems;
e. Power scheduling and accounting;
f. Automatic time-error correction;
g. Minimization of accumulated scheduling imbalances;
h. Transmission congestion management
i. Reactive power control
j. Contingency monitoring and power system security analysis; and
k. Remedial actions to control network instabilities and contain network outages.

A significant amount of effort will be required to develop the back-bone WEPEX systems in a manner which efficiently interfaces with the existing systems to allow the continued safe and reliable operation of Californiaís interconnected electric system. The use of the existing systems are the reason the Commissionís 1998 start date is feasible. However, just because the systems are available and form the foundation for accelerating the start date, should not be interpreted as their ability to support a fully competitive market. No one today or two years from today can make that judgment.

To further complicate the transition, is the parallel development of the commercial systems needed to support the competitive market structure adopted by the Commission. Like their electric system counterparts, the commercial functional requirements will require new systems and approaches, while at the same time, they must integrate with the existing (and future) metering and billing infrastructures. Although these systems wonít have the added complexities of having to operate ìat the speed of lightî, they involve billions of dollars in transactions and will have to contend with their own unique set of coordination protocols and procedures. Further, existing systems will need to be tuned to new operating conditions, since competition will open new transmission paths, although some evidence presented to DAWG suggests that much can be done using existing systems.

A final subtle complicating factor is the tension which may arise as the actions of the existing and new players in the interconnected systems become "competitive" rather than "cooperative". The interconnected grid has functioned very well to date because of the cooperative nature of each utility doing all it can in helping the others. Under the new competitive structure, there may be a reduction in cooperation during the transition period, as participants may be more preoccupied with competitive issues than with trying to identify and correct the many problems that will arise. Of course, this is less an issue at the transmission level, where the ISO administers multiple transmission systems and control areas.

It could be that the initial winners in the new competitive market could be those who discover ways to exploit a transitional problem, rather than correct it. This is not to say that efforts to try to ìbeat the systemî are wrong, as such represents an inherent element of a competitive market, but such efforts may affect the entire WSCC grid and may require a more cautious implementation.

4.2.2.2 Settlement Data Processing Capabilities

WEPEX's Dispatch Integration and System Infrastructure (DISI) Team and DAWG's Implementation and Metering/Communication committees have both examined whether ISO data processing capabilities are a constraint to the transactions of imbalance computations that must be performed on a daily basis. The uncertainties of the scheduling coordinator concept, along with the ongoing development of the ISO/SC interface, have impeded resolution of information requirements, hence metering and communication data needed for imbalance settlements and energy billing. The WEPEX DISI Team has submitted a proposed RFP to the WEPEX Steering Committee for necessary system development work.

Furthermore, WEPEX is considering limiting the activity during the initial twelve months by the number of accounts that can be processed manually, to insure transaction settlement can occur with the loss of the WEPEX systems. It is anticipated, barring a requirement to make major changes to the WEPEX systems, rules and protocols, that the availability of the data processing systems will steadily improve during the initial year. The rate of phase-in will depend greatly on the success of the WEPEX systems, their administration, the capabilities of the Scheduling Coordinators, and WEPEX's overall ability to interface with the commercial aspects of the new market structure.

Also, there has been considerable discussion regarding Scheduling Coordinators and does their presence simplify or eliminate the ISO's data processing concerns. On first glance, the Scheduling Coordinators appear to be the magic elixir for direct access, as they simplify the data management concerns of the ISO. However, there remain significant uncertainties driven by the financial risk they will incurring, their credit requirements, the computer and communication systems (may include back-up systems) they will require and the regulatory oversight and possible registration requirements they will receive. It could very well be that Scheduling Coordinators may become very selective in the service they provide and the requirements they place on the customers who will use them.

To date, only ISO communication protocols and systems with the Scheduling Coordinators are being designed. No such designs are currently taking place regarding how customers and generators will interface with the Scheduling Coordinators. The Scheduling Coordinators will not only be required to interface with customers and the ISO, they will also have to be able to track individual hourly schedules at all energy receipt and delivery points they use, though not necessarily on a daily basis. What Scheduling Coordinator protocols are needed, along with what

system, regulatory and financial requirements they need to comply with, could significantly affect the phase-in of direct access. There are, however, many on-line data processing and billing systems in existence today (banks, credit cards companies, credit verification agencies) that process data continuously. These systems or others may be adaptable to ISO or SC needs.

4.2.2.2.1 Alternative: Scheduling Coordinator Burdens Are Minimized Resulting in No Data Processing Constraints Beyond 1998

While the ISO's settlement process will not require the capabilities once imagined prior to the scheduling coordinator concept, the functions of the ISO are without precedence, and no existing computer hardware/software system exists to be adapted to suit these needs. The delays experienced by WEPEX in resolving the Trust ratemaking procedures with the CPUC may have jeopardized the January 1, 1998 start date already. The result of the delay and the complexities of even a shielded ISO mean that a fully capable ISO settlement process may not be ready until sometime into 1998. This requires that direct access participation be limited, or that compromises with actual imbalance settlement allocation be accepted.

The Scheduling Coordinator concept is intended to insulate the ISO from the enormous volumes of imbalance settlement computations needed to determine and allocate settlement costs to responsible parties. Using the Scheduling Coordinator as the interface between the customer and the ISO greatly reduces the computer software/hardware system that the ISO needs. The ISO will merely address imbalances with the several hundred scheduling coordinators and their loads for each of the transmission/distribution interface points. Once the ISO fully develops its computer system, its capabilities will not need to change appreciably even when participation in direct access is growing rapidly. The ISO data processing system is not a technical rationale for restricting eligibility to direct access, except perhaps in the initial 1998 period.

On the other hand, the Scheduling Coordinator computer software/hardware system does need to scale in capacity as participation in direct access grows. If there are numerous scheduling coordinators, and more scheduling coordinators are allowed to enter the business if market conditions warrant this, then the computer software/hardware systems capacity for the collection of scheduling coordinators may be a series of separate modules, added a few at a time. Each new scheduling coordinator may have to invest in additional computer software/hardware systems as a necessary investment prior to opening up shop. Existing scheduling coordinators expanding their number of transactions can readily add another module that operates in parallel with their existing system. The combination of multiple, even numerous scheduling coordinators and the prospects for modular data processing systems, suggests that settlement data processing will not be a problem for the industry beyond 1998. As a result, we need to ensure that Scheduling Coordinators are encouraged to enter the business with the fewest possible burdens so that they can have a data processing capability to support rapid direct access expansion.

Alternative 4.2.2.2.1 PROS:

(1) Scheduling Coordinators will relieve the burden of the ISO and retailers and aggregators will relieve the burdens of the customers and the generators. Although the systems may be complex, having multiple, sophisticated players may reduce those complexities.

(2) Numerous Scheduling Coordinators may minimize problems with constraints on direct access from data processing systems.

(3) Minimal requirements will encourage Scheduling Coordinator business formation to match or exceed the data processing needs of direct access.

Alternative 4.2.2.2.1 CONS:

(1) Substantial amount of systems and interface testing will be required. Protocols are yet to be developed. There have never been any ìBig-Bangî installations involving major computer/control systems.

(2) Although the use of Scheduling Coordinators simplifies the ISO data management, they may complicate the overall market structure as one more "for-profit" entity is in the scheduling chain.

(3) Financial, scheduling, regulatory and consumer protection requirements for the Scheduling Coordinators are uncertain. If they are significant, it could influence the formation of these firms, and possibly severely affect any scheduled phase-in of eligibility.

4.2.2.2.2 Alternative: Scheduling Coordinator Problems Result in Data Processing Constraints Beyond 1998

If there are numerous restrictive requirements on Scheduling Coordinators, large capitalization requirements to cover "float" and customers are permitted to have numerous complexities in their bilateral contract or aggregation arrangements, then expansion of scheduling coordinator functionality may not keep pace with interest in direct access. This would not stem from Scheduling Coordinator data processing problems, but rather from some unforeseen market impediment for the Scheduling Coordinator concept. However, if new scheduling coordinators failed to enter the business, this could place restrictions on the numbers of customers (via their data processing transactions) that can be accommodated.

Alternative 4.2.2.2.2 PROS:

(1) customers are protected from sharp business practices.

(2) customers are enabled to make many complex arrangements contract arrangements, and reduced frequency of settlement requiring the Scheduling Coordinator to cover "float".

Alternative 4.2.2.2.2 CONS:

(1) fewer of them will be motivated to enter the business, reducing the capacity of the industry to process imbalance transactions, and constraining direct access participation.

(2) stringent rules and requirements may impede innovation that new entrants bring.

4.2.2.3 Metering/Communication Systems

A retail restructuring emphasis on consumer choice manifests itself in customers paying more attention to the options and prices of these options for energy services, and being able to respond in more ways than they were able under the traditional industry structure.

Installation of universal interval metering and two-way communication systems for all 12 million customers in California would require a multi-year effort. This section will summarize the technical issues associated with metering and communication systems deployment, and the alternatives will illustrate some of the strategies to make this deployment successful. Among these are not even requiring advanced metering and communication systems for small direct access customers in the early years.

An assessment of metering/communication systems in several alternative installation approaches requires: (1) evaluate metering/communication systems options compatible with information requirements and various installation/ penetration scenarios; (2) resolve issue of UDC versus other entity installation and control; (3) resolve/identify options for UDC investment recovery for metering/communication systems; (4) develop understanding of industry ramp-up capabilities; (5) develop understanding of installation of communication systems issues; (6) evaluate issues concerning data flow into billing systems, including: different data, volume of data, data distribution to multiple entities, bill payments forwarded to multiple entities, and new system development and shakeout timelines; (7) integrate all considerations into a decision-making framework. A large portion of this work has been accomplished by the Metering and Communication Systems Committee of DAWG, and is documented in Chapter 8.

Three alternative scenarios provide a major portion of the viable alternatives from which the CPUC must choose:

(1) universal installation of metering and communication systems controlled by a monopoly;

(2) the UDC installs all metering and communications systems, limited to those required for all customers desiring direct access and those mandated by the CPUC; and

(3) the energy supply provider installs the metering and communication system.

More details concerning costs variation of advanced metering and communication systems for various penetration rates can be found in Chapter 8.

4.2.2.3.1 Alternative: Universal Meter and Communication System Installation by a Monopoly

This alternative suggests that the CPUC directs that advanced interval metering and two-way communication systems are to be installed universally. The entity controlling this process of installation and operation is a monopoly, which might be either the UDC, a standalone INFOCO regulated by the CPUC, or a industry stakeholder information clearinghouse. This alternative has the most standardization of equipment, data transfer protocols, and data processing since a monopoly controls all decisions. The only departures from the standard system are for those rural areas where customer density does not justify the standard equipment package.

Alternative 4.2.2.3.1 PROS:

(1) lowest cost for all customers;

(2) supports orderly transition to full customer choice;

(3) standardization;

(4) no duplication of facilities and effort;

(5) relative simplicity.

Alternative 4.2.2.3.1 CONS:

(1) the longest installation lead-time since all customers receive new equipment.

(2) it may not be necessary for all customers to have interval meters. A mandatory meter requirement therefore would impose an unnecessary cost on the system at large; and

(3) dampens competition in meter supply.

4.2.2.3.2 Alternative: UDC Meter and Communication System Installed Only for Those Requiring It

This alternative suggests that the UDC retains the sole authority to install and operate metering systems, and that only customers participating in direct access and those otherwise mandated by the CPUC obtain advanced interval meters and communication systems. Other customers, primarily small commercial and residential continuing as full service customers of the UDC, continue to be served by existing consumption meters. This alternative has considerable diversity since large portions of the customer base continue to use old equipment and procedures, while customers requiring advanced systems use those which make the best sense in that specific application.

Alternative 4.2.2.3.2 PROS:

(1) customers who receive the equipment pay for it;

Alternative 4.2.2.3.2 CONS:

(1) the cost per unit of this alternative is higher than Alternative 1;

(2) very unequal quality of service is provided, and some customers cannot obtain advanced information services when they remain full energy service UDC customers;

4.2.2.3.3 Alternative: Energy Supply Provider Installs the Meter and Communication System

Some parties believe that the Policy Decision precludes this alternative (D.95-12-063, p. 80). This alternative suggests that multiple parties provide metering services in the future. Customers participating in direct access have their energy service provider (ESP) install interval metering which suits the business needs of these two parties. UDC virtual direct access customers have the UDC install an interval meter and two-way communication system at the customers expense, both for investment and incremental operating costs. Large commercial and industrial customers who are not participating in direct access have an interval meter and two-way communication system installed by the UDC with costs recovered in their tariffs. Other UDC energy service customers continue to use existing monthly consumption meters. This alternative has the greatest diversity of equipment, data communication systems and protocols, and in what is done with the data.

Alternative 4.2.2.3.3 PROS:

(1) energy service providers are the most motivated to install equipment to initiate direct access service relationships;

(2) may reduce costs and risk of obsolescence to customers.

Alternative 4.2.2.3.3 CONS:

(1) a highly fragmented system makes it very difficult to change energy service provider, to maintain continuous customer consumption databases, and to use data for analytic purposes;

(2) the UDC is dependent upon the ESP to remit revenues for distribution services, CTC, or public goods charges unless the UDC retains the traditional meter and continues its meter reading activities for that customer.

4.2.2.4 Constraints of UDC Billing Systems

D.95-12-063 creates a UDC from the distribution and customer service functions of the IOUs. The apparent presumption of the policy decision is that these distribution and customer service functions remain exclusively with the UDC. If this is to be the case, then UDC billing systems will have to revised substantially to address direct access requirements. They will also have to be revised to address other fundamental elements of restructuring, and would at a minimum need to be able to identify the major functional separations (generation, transmission, distribution and customer service, CTC, and PGC) that the CPUC has decided to implement. At the same time, direct access providers clearly expect to bill their customers for energy services rendered, potentially subjecting the customer to bills for duplicate services. This section addresses several alternatives for billing direct access customers in the context of these difficulties.

4.2.2.4.1 Alternative: UDC's Provide Exclusive Billing for All Customer Services

If UDCs provide exclusive billing of all customer services, and in effect, remit energy revenues to the private energy service provider, remit other revenues per regulated tariffs for ISO and PX services, and retain those revenues associated with UDC services, then the UDC billing system becomes a central controlling factor in the numbers of customers that can participate in direct access. Thus, UDCs face several questions:

a. what is volume of direct access billing that they can expect to be processing in 1998 and 1999?

b. of the systems available/adaptable for that time period, what processing capabilities could be in place?

c. are there any ancillary systems, such as translation of hourly reads through telephone-based modems for entry into the billing system, a constraint?

d. given the current requirement that UDCs perform all distribution services, but the possibility that distribution function unbundling now under investigation by the CPUC may alter UDC responsibilities, what is the appropriate ratemaking treatment of any investments/expenses to augment bill processing capabilities?

Before concluding that billing systems that need to be in place in 1998 are an issue, these questions (and perhaps others) must be addressed and resolved. Without completing this assessment, a few advantages and disadvantages can be identified.

Alternative 4.2.2.4.1 PROS:

(1) There will be fewer problems with UDC distribution function, CTC, and PGC revenue collections;

(2) Standardization;

(3) Fewer entities involved means less confusion.

(4) Utilities are expected to have financial incentives to improve service.

Alternative 4.2.2.4.1 CONS:

(1) Some parties contend that this alternative severely limits new entrantsí ability to offer value added and new services which may be of significant benefit to customers. These benefits could be in the areas of energy efficiency, bundling with other services and other more innovative products such as donations and frequent flyer miles. Even the format could be different as businesses move to on-line communications, further increasing efficiency, reducing paper use and lowering costs.

4.2.2.4.2 Alternative: ESPs and UDCs both Bill for Respective Services

This alternative allows ESPs to bill directly for their services provided. The UDC would continue to bill as it has for the foreseeable future. The customers receives two bills and has to pay both, which results in a duplicate service.

Alternative 4.2.2.4.2 PROS:

(1) the CPUC has no difficult decisions to resolve;

Alternative 4.2.2.4.2 CONS:

(1) total costs may be higher than in any other alternative;

(2) customers may dislike receiving two bills.

4.2.2.4.3 Alternative: ESPs May Contract with UDCs for Consolidated UDC Billing

This alternative provides an opportunity for the UDC and the ESP to develop a mutually beneficial arrangement in which the ESP contracts with the UDC to perform its billing activity. A contractual service would be outside of CPUC direct control, at least for bill format and other aspects which the ESP might wish to customize.

Alternative 4.2.2.4.3 PROS:

(1) the costs to the customer would lower than in Alternative 2 because no duplicative services are provided, and might be lower than in Alternative 4 if the UDC's higher volume lowered costs per unit;

(2) maintenance of databases for continuity and analytic purposes would be enhanced compared to Alternative 2;

Alternative 4.2.2.4.3 CONS:

(1) the CPUC would have to authorize this activity, and perhaps exempt such billing from bill format constraints imposed on UDC energy service customers.

4.2.2.4.4 Alternative: The Energy Service Provider Does All of the Billing

The ESP could have the opportunity to send out the only bill to the consumer, if the UDC fully unbundled its billing activities. Distribution costs should include only the distribution and maintenance of the power and emergency services not the billing and customer service. It should be an option by the ESPs to purchase billing and customer service from the UDC at the same price that they unbundle it at. The UDC should also be required to read the meter and send the information to the ESP at a regulated price. Thus, the ESP could send out a complete bill for transmission, distribution and energy. The ESP would remit payment to the UDC based on the meter read for transmission and distribution. This creates an efficient market with an opportunity for competition for residential and small businesses.

It should not be a requirement that the UDC do some portion of the billing. It is necessary that the UDC be able to unbundle the aggregated and contract customers customer billing information from the system. The UDC must be able to provide on a monthly basis within a reasonable time period from the meter read, the change in the reading from one month to the next. The new

entrant will prepare a bill and within 45 days remit payment to the UDC for the transmission and distribution portion of the bill. The new entrant will be responsible for all collections. This only works when the UDC has unbundled the service based on total costs of billing.

Alternative 4.2.2.4.4 PROS:

(1) for combination service ESPs (energy plus other activities, such as telephone service) this would be the least cost billing arrangement for the customer;

(2) provides for maximum opportunity for retailers.

Alternative 4.2.2.4.4 CONS:

(1) CPUC regulated revenues for UDC distribution services, CTC repayment, and PGC would be subject to more difficult auditing and verification of entities not subject to direct and ongoing CPUC authority and control;

(2) some parties believe that any UDC savings would be minimal because UDCs would continue to do other billing functions outside of the “bill presentation.”

(3) the ability to purchase billing services at the same price it was unbundled may not be fair because these prices would be based on economies of scale that may not be applicable to the services offered.

(4) there is increased potential for confusion among smaller customers over who to contact for problems or questions.

(5) new regulation may be required for CPUC to retain control over bill contents and inserts.

4.2.3 "Success Guarantee" Rationales for Limiting Eligibility

Unlike the technical considerations that may constrain the eligibility for direct access, this second category of rationales suggest limiting eligibility because it would be "unwise" to allow full eligibility, since to do so might jeopardize successful implementation. For example, announcing to all customers that they have the opportunity of selecting a direct access provider as of 1/1/98, but having only a partial capacity to serve direct access by a limited number of certified providers could result in far more customer contacts than can possibly be handled by these providers. This could result in unsatisfactory service, disappointment, and disillusionment with the prospects of direct access.

Alternatively, the CPUC could allow certified entrants to market their services provided they met certain customer service standards. The marketing efforts would be scaled to the capacity of

the firms to provide these services, and no major set of disappointed customers would have been created through an overly optimistic announcement. Unfortunately, this process would provide much less ability to provide benefits to all customer classes through a mandated customer class representative criteria. While the market might begin in an orderly manner, it might not meet other criteria of "success."

To avoid these potential problems and to "guarantee success" for introduction of direct access with the constraints that the CPUC has already imposed, a limitation on eligibility of customers could be introduced. Clearly the process of selecting the customers that would be offered the opportunity would be accused of being unfair, but the explanation of "having to wait your turn" may be more palatable than a free-for-all in which many customers are not served. In addition, there may be opportunities to permit customers with different risk tolerance to participate in the early stages, while delaying lower risk tolerant customers later in the phase-in queue.

Examples of customer service rationales include:

1. *immature industry customer service constraints* result in difficulties of new firms staffing up to handle inquiries from millions of small residential and commercial customers who will have many questions about general issues of restructuring as well as specific questions about individual company offers. These questions will burden both UDC customers service organizations as well as new energy providers.

2. *necessity to use both 1997/98 for testing protocols* recognizes that various customer education/notification of eligibility protocols have to be developed to allow successful marketing strategies that appeal to all customers given broad disparities of education, language, familiarity with contracts, and other issues.

3. *coordination of data/information flows* recognizes that many data handling activities will be different, that complex systems to notify customers and process their responses have to be developed and implemented, and protocols have to be developed and implemented to ensure that basic billing continues to occur when direct access begins.

4.2.3.1 Immature Industry Customer Service Constraints

This section is a placeholder pending further investigation and understanding of this issue. Further assessment requires: (1) develop estimates of the proportion of small customers that might be willing to participate in year 1 and year 2; (2) evaluate the number of customer contacts, amount of paperwork, and any necessary hardware purchases/installation to accommodate direct access; (3) determine whether the capabilities of IOUs and market providers could handle this volume of customer contact; and (4) identify upper limits of customer contacts to ensure satisfactory performance by IOU in 1997, UDC in 1998, and market providers in both years. Some parties believe that this section underestimates the expertise of potential new entrants.

Many of them have years of experience providing consumer products and services in other industries, particularly industries that have moved from a regulated to an unregulated environment.

4.2.3.2 Opportunity to Use 1997/98 for Testing Protocols

This section is a placeholder pending further investigation and understanding of this issue. Testing through the use of pilots emerged as a topic that the Implementation Committee could address in its scope of work, but DAWG recently agreed at the June 7, 1996 meeting to postpone development of pilot or testing programs beyond the August 30 WG report. Whether the concerns about consumer education and reductions of those concerns are sufficient to delay full eligibility in order to reduce these concerns has not yet been established.

This topic needs to be assessed more fully to determine whether intensive program testing, especially for small commercial and residential customers, can measurably improve protocols of notification, educational materials, and other facets critical to successful experiences with direct access selection.

4.2.3.3 Coordination of Data/Information Flows

This section is a placeholder pending further investigation and understanding of this issues. This topic is implicit in discussions of the hardware aspects of DISI Team development of ISO settlement hardware/protocols, DAWG Implementation Committee discussions of mandated participation of residential and small commercial customers, but some parties suggest it be highlighted in its own right.

Once a clearer image of scheduling coordinator roles and responsibilities, and the interface between the UDC and generation service marketers emerges, it will be possible to develop protocols to determine how data changes hands, and to conduct an assessment of possible constraints.

4.2.4 Equity Concerns With Implementation of Oversubscription Rationing

Unlike the discussion in section 5.1.3, which discusses representation of all customer classes in direct access, this section addresses equity concerns with implementation of constrained eligibility. In general, the greater the constraints on aggregate participation, the more severe become the concerns about the equity of any one customer's selection. If direct access is effectively unconstrained, then clearly no equity issues are encountered. If direct access must be highly restricted because there are large numbers of interested customers in the face of technical

constraints, then many issues arise in determining how to ration eager participants in a fair manner.

Examples of equity concerns include:

1. *developing a universal customer database matching the phase-in descriptor* for use in the selection process.

2. *defining customer classes* for purposes of ensuring broad participation among all groups.

3. *restrictions on participation to maintain parity* in energy costs among similarly situated firms competing within a given industry.

4.2.4.1 Developing a Universal Customer Database Matching the Phase-in Descriptor

Once the CPUC has selected its preferred phase-in descriptor, assuming phase-in is required, a universal database must be developed that provides data on each customer using this descriptor. While this is a seemingly simplistic task, the fundamental unit that utilities have used is the customer account, so some effort would have to be employed to construct a universal database from existing ones. There may be multiple meters per customer account. There may be multiple accounts at a single premise. There are clearly many firms with multiple premises that might consider themselves a single customer. Thus, if number of customers was selected as the means for describing eligibility patterns through time, an effort would have to be made to define customers in an unambiguous manner for all customers. Once this definition was developed, then IOU account data would have to be processed to develop a customer database. It might be necessary to contact customers in this process to provide a preliminary result, and ask them to identify any discrepancies from their sources of data.

An example of a problem to be resolved is the treatment of street lights and traffic signals. Since street lights are frequently on timeclocks or photosensors, and the wattage of the luminaire is known, many streetlights do not have meters, and thus are not entered into the population of accounts. A large number of streetlights owned by a municipality might be considered as a single customer for eligibility purposes, or the entire municipality might be considered a single customer even though a collection of accounts, and unmetered streetlights composed the city's load served by the utility. The resolution of these issues before open season notification begins is crucial to reducing potential for disputes.

If the descriptor selected was annual energy consumption for a calendar reference year, then various efforts would be required to develop a universal database for all customers for this value. Again, this is more complex than it appears. For example, even with annual energy as the descriptor, various customers from the year chosen as the reference would have partial records

and some agreed upon methods would be required to complete the missing values to develop an annualized total. Several alternative methods could be debated and the choice might advantage or disadvantage one customer over another.

Finally, if the descriptor selected is peak demand, considerable effort would be required to develop peak demand values for the huge numbers of residential and small commercial customers for which peak demand has never been metered. Many methods could be used for this imputation process, all of which have advantages and disadvantages for various subgroups of residential and small commercial customers.

While seemingly of no value, developing such a universal database would be essential to fair implementation of a oversubscription selection process. Absence of this database prior to open season solicitations and requests for authorization to participate would lead to numerous complaints and disputes, which would eventually consume much goodwill and detract from the direct access process.

4.2.4.2 Defining Customer Classes to Ensure Representative Participation

While D.95-12-063 clearly requires participation of all customer classes, what is meant by customer classes has not been defined. Frequently these customer classes are described in terms that suggest economic, not tariff definitions. Each utility has a different set of tariffs that group together in various ways to define revenue accounts. The SIC code classification of each non-residential account required by CEC regulations provides a basis for economic groupings by industry or business type.

Utilities, customers and others might need to collaborate to develop a protocol for making a singular identification of a customer to a specific class, especially addressing multiple account customers which may be on different rate schedules, if classes were to be used as a basis for achieving representative participation.

4.2.4.3 Restrictions on Participation to Maintain Industry Parity

Some industry representatives express concern that there may be a few industries where competitors are few in number and finely balanced in production costs. Providing direct access to one such firm while denying it to others may unsettle the competitive balance for reasons which are an artifact of regulatory decision-making, not the marketplace. Generally, the issue has been discussed as all such firms or no such firms would participate in direct access simultaneously. To accomplish this requires recognition of the industry and some form of identification of specific firms within to which such treatment should be imposed, or a method of selection that does not allow one customer to participate and another to be excluded, such as pro rata eligibility.

4.2.4.3.1 Alternative: CPUC Imposes Group Participation Requirements

Based on this report, or the comments of parties to this proceeding once this report has been submitted, the CPUC could impose group participation requirements on some specific industries. These requirements might be of the form: all customers in SIC 303 must wait until year 2000 to be eligible to participate in direct access, and in that year if phasing is still being conducted, all members of this industry would be authorized to participate if they chose to submit requests.

In order to accomplish this specificity of CPUC-imposed direction, the CPUC must have developed an understanding of the number of customers, accounts, annual energy and/or peak demand, role of energy in the competitive balance among firms, and interest in these industries to participate in direct access. This will require CPUC staff or IOUs to provide such an assessment as a supplement to this report for use in implementing this approach should the CPUC decide it is warranted.

Alternative 4.2.4.3.1 PROS:

(1) specificity is gained by policy decision, without awaiting voluntary actions from industries;

Alternative 4.2.4.3.1 CONS:

(1) failure of industry to make its case in a series of interested party filings or through a trade association may reveal that the concern is not broadly based in the industry, thus perhaps having imposed a constraint that was not warranted;

(2) substantial effort by the CPUC and/or the IOUs may be needed to identify these industries, and to develop special eligibility rules for them; and

(3) firms unhappy with these constraints may seek to manipulate the eligibility process to evade what they consider to be an unfair restraint of their "right" to participate.

4.2.4.3.2 Alternative: Industries Impose Restrictions On Themselves Outside of Direct Access Program Requirements

If industries possessing these concerns were willing to identify themselves and come to agreements through a trade association, rather than requiring that the policing authority of the CPUC through the IOUs insure discipline among the firms involved, then numerous problems might be simplified. It is unclear whether to expect that any industry can, through cooperation, police themselves without claims of anti-competitiveness by non-cooperating firms.

Alternative 4.2.4.3.2 PROS:

(1) It would be much simpler for DAWG, the CPUC, and resulting IOU implementation efforts for industries to choose to do this themselves, thus avoiding a mandate;

Alternative 4.2.4.3.2 CONS:

(1) it may be unrealistic to expect a whole industry to come to an agreement when specific members might gain an important advantage by frustrating a voluntary restraint; and

(2) it may be illegal for trade associations to negotiate such an agreement.

4.2.4.3.3 Alternative: Prices are Regulated During Phase-In

During the phase-in period, prices would continue to be regulated.

Alternative 4.2.4.3.3 PROS:

(1) concerns about cream skimming and unequal access to benefits are eliminated;

(2) systems can be designed, built, and tested with all customers sharing the cost responsibility; and

(3) customers will want price benefits to take effect sooner, so they will be more cooperative in helping design systems and ensuring the systems work.

Alternative 4.2.4.3.3 CONS:

(1) customers seeking immediate benefits cannot do so until phase-in is complete.

4.3 Specific Phase-In Proposals

The parties have not reached consensus on a particular phase-in proposal. In fact, the parties do not agree whether a phase-in as called for in the Policy Decision is even necessary, with some parties remaining convinced that it is not. Thus, from a temporal perspective, several alternatives have been proposed:

a. direct access is open to all customers meeting minimal requirements on 1/1/98;

b. direct access is limited in 1998, but becomes open to all customers meeting certain contractual and equipment requirements on 1/1/99; and

c. direct access is phased in over a multi-year period with final opportunities not available until 2002 or 2003.

Some parties do not believe that temporal phasing is required, and suggest that direct access should not be limited in aggregate participation per se, but is limited to those customers with required equipment and contractual requirements, which themselves may be phased in over multiple years. Another non-temporal alternative is contracts-for-differences, which would not require any hardware development at all.

While many variations exist, these four groupings encompass the major proposals put forward by parties to date. The details of subsections 4.3.1-3 provide a discussion of the major elements that can be combined to develop specific details of the programs that are variations within the broad themes of the four groupings. Subsections 4.3.2 and 4.3.3 discuss the non-temporal alternatives.

4.3.1 Temporal Phase-in Proposals

Temporal phase-in relies upon use of an aggregate descriptor to constrain the amount of direct access that can take place in each of various years, beginning with 1998. As noted in the introduction to this section, these time periods range from a single year to four or five years.

4.3.1.1 Alternative: Direct Access Open to All Customers Meeting Contractual and Equipment Requirements on 1/1/98

This alternative eliminates the phasing of direct access, even a single year's testing efforts, and opens direct access to all customers on 1/1/98. This is a change from the special treatment of 1998 in CPUC D.95-12-063, and implies a reduction in the nature of the special requirements for direct access participants.

Alternative 4.3.1.1 PROS:

(1) no special rules for determining eligibility have to be determined by the CPUC and implemented by the IOUs/UDCs;

(2) customers expressing interest in participation will all be accepted, and will not suffer possible rejection as exist for phase-in alternatives with the possibility of oversubscription.

(3) no irrational benefits accrue to selected participants; and

(4) allows market to dictate which of the technological barriers require solutions, and the timeframe for those solutions. It also does not force a certain type of technology.

Alternative 4.3.1.1 CONS:

(1) The tradeoff for quick eligibility is reduced functionality and flexibility. If everyone is eligible in 1998, many metering, billing, settlements, and customer service work-arounds would be needed just to provide a service so basic that it would not satisfy many customers and new service providers.

(2) Several technical constraints are likely to arise (i.e., most customers would probably use existing, rather than the most technically appropriate, meters; UDC billing systems, while probably capable of producing simple bills for direct access customers, probably could not provide a desirable level of detail; and interactions among systems are likely to exhibit glitches).

(3) consumer education and protection efforts would be abbreviated, if not inadequate, leading to customer confusion and dissatisfaction.

4.3.1.2 Alternative : Direct Access Limited in 1998, But Open to All Customers Meeting Contractual and Equipment Requirements on 1/1/99

This alternative continues the presumption that 1998 is required for a staged, initial direct access effort to "work out the bugs," and that full eligibility for direct access for all customers could take place on 1/1/99. This alternative offers more than twice as much lead-time (measured from a June 1997 CPUC decision concerning direct access to the point at which all customers would be eligible) as Alternative 1, thus many more of the technical considerations of new metering/communication systems (if needed), revised or replaced billing systems, ISO imbalance cost allocation protocols, and customer education/protection programs could be refined and implemented in more efficient ways.

Alternative 4.3.1.2 PROS:

(1) significantly more lead-time is available to develop new mechanisms to compute and allocate direct access costs specific to each customer;

(2) probability of major breakdown in education, consumer protection, and customer service activities greatly reduced, thus increasing chances of success for direct access;

Alternative 4.3.1.2 CONS:

(1) relative to Alternative 1, this alternative would reduce the opportunities available to customers and competitive service providers in 1998;

(2) the CPUC has to establish through a policy decision the broad parameters of a direct access program with limited eligibility in 1998, and UDCs have to implement these decisions.

(3) one year still may not provide enough time to adequately implement customer choice and work out systems bugs for all customers.

4.3.1.3 Alternative: Direct Access Is Phased in Over a Multi-Year Period

The original direct access scheme introduced in the MOU proposed a multi-year phase-in of eligibility based on peak demand of load involved. While the original proposal suggested a six year phase-in, some parties now suggest either three or four year variants are likely. Another utility, while included within this table of peak demand allocations, rejects this alternative for its service area, and supports a transaction-based limit, if any is identified.

4.3.1.3.1 Variant A: All Customer Classes Included Within Peak Demand Limits

The parties to the MOU included a specific proposal for phasing direct access and enumerated various eligibility parameters. The CPUC D.95-12-063 endorsed the aggregate levels of peak demand participation, but not the other parameters of the MOU proposal. In D.96-01-006, the CPUC indicated that the peak demand schedule endorsed was the slowest permissible phase-in for direct access, and encouraged more rapid phase-in schedules.

Capacity Eligibility of MOU Proposal

Eligibility Criteria	1998	1999	2000	2001	2002	2003
SCE MWs eligible	800	1400	2200	4000	8000	all
PG&E MWs eligible	800	1400	2200	4000	8000	all
SDG&E MWs eligible	200	350	550	1000	2000	all

Alternative 4.3.1.3.1 PROS:

(1) improved opportunities to ensure that direct access is conducted successfully, especially in ability to avoid failure of major information systems needed to transfer data among UDCs, energy service providers, scheduling coordinators, PX, and ISO.

Alternative 4.3.1.3.1 CONS:

(1) many more customers are denied an early opportunity to participate in direct access than with previous alternatives;

(2) some marketers, brokers, and aggregators may not be able to survive on the smaller levels of participation implied by multi-year phase-in;

(3) the peak load descriptor for the size of the program requires imputed data for small commercial and residential customers, rather than use of actual data, thus requiring another analytic step subject to dispute.

4.3.1.3.2 Variant B: MOU Proposal With a Year Three Evaluation Point

One party has proposed a variation upon the original phase-in schedule included in the September 1995 MOU. The three years of a megawatt-delimited peak demand phase-in schedule described in the MOU would be preserved, but after year 3 a major review would be conducted to determine whether to continue phasing, and if so on what schedule. The ISO, using real operating experiences, would be the primary judge of how quickly to phase in direct access.

The pros and cons are the same as for Variant A.

4.3.1.3.3 Variant C: Accelerated Conclusion of MOU Proposal With Full Eligibility by Year Four

PG&E has reached a partial settlement with numerous parties in its Diablo Canyon Accelerated Cost Recovery/Rate Freeze proposal. In this proposal, PG&E and these parties assert that all customers can be eligible for direct access within four years.

4.3.1.3.4 Variant D: Residential Class Is Excluded From Peak Demand Limits, and Has Its Own Transactional Based Limitation

A variant of the original MOU peak demand limits which attempts to recognize the great disparity of size among various participating customers suggests that the original peak demand limits included within the MOU be interpreted as applying only to the non-residential classes of customers. All aspects of that interpretation would remain as identified within the original proposal. In addition, the residential sector would be allocated a participation rate linked to the numbers of transactions that UDC billing systems and meter/communication systems could support through time.

Alternative 4.3.1.3.4 PROS:

(1) improved opportunities to ensure that direct access is conducted successfully, especially in ability to avoid failure of major information systems needed to transfer data among UDCs, energy service providers, scheduling coordinators, PX, and ISO;

(2) compared to Alternative 3 (variant A), no imputation of extrapolation of residential customer energy data to determine peak load is required.

(3) makes more residential customers eligible

Alternative 4.3.1.3.4 CONS:

(1) many more customers are denied an early opportunity to participate in direct access than with some previous alternatives;

(2) some marketers, brokers, and aggregators may not be able to survive on the smaller levels of participation implied by multi-year phase-in;

(3) managing multiple eligibility requirements increases administration costs and complexity;

(4) may actually result in less participation by residential customers than other alternatives.

4.3.1.3.5 Variant E: Conduct a Massive Lottery

A proposal developed during the course of the DAWG discussions is linked to conducting a massive lottery. Each interested customer would be placed into the lottery, with a drawing determining which would be authorized to participate.

4.3.2 Alternative: Participation in Direct Access is Open to All Customers with Required Equipment and Contractual Arrangements

This approach to eligibility for direct access rejects "arbitrary" limits on peak demand or on schedules of meter/communication system installation and suggests that direct access be permitted for any customer possessing certain required equipment and contractual arrangements. This approach recognizes the uncertainties of the development of billing systems, of metering/communication systems installation, of bill processing systems, and instead of forecasting the rate at which the capacity of these systems will be put in place merely says that once the customer/provider have them then the customer can participate in direct access. This approach places pressure on the installation of these systems by either the UDC or private parties, and would accentuate policy focus on these underlying institutional responsibility decisions.

Those customers who have installed submetering and telemetry equipment for building or facility energy management purposes may be able to have this equipment certified as meeting revenue standards. For such customers, the ability to satisfy direct access requirements might be a minor exercise.

A hypothetical set of requirements to be put in place by the customer or his/her energy services providers that would permit participation in direct access include:

a. *metering/communication systems* capable of measuring energy consumption data and transmitting this data to a bill processing center:

   1. small customers -- traditional monthly consumption meter manually read by a meter reader; and

   2. other customers -- hourly interval meter with an electronic communication system capable of uploading hourly reads for a day on a daily basis,

b. *customer service contract* delineating split in customer service activities between the UDC and the energy service provider, at least specifying an agreement from a bill processing center to support needed billing computations according to energy provider specifications; scheduling coordinator settlement protocols, and UDC tariff requirements.

c. *energy supply contract* covering all load of the customer for a one year period with 30-day notification to UDC period for return to UDC service.

d. *system integration contract* with scheduling coordinator which specifies protocols for forecasting hourly loads, use of consumption data and/or load profiles for use in settlement of imbalances, and process for remittance of customer payments to all appropriate parties.

e. *UDC distribution contract* establishing the tariff for distribution service, coordination arrangement for CPUC-regulated service payment, and agreement to pay CPUC-directed CTC charges.

These requirements could be refined, or alternative ones developed. Associated with establishing these requirements is clarification of who is responsible for providing these requirements to the customer, e.g. what are the roles of the IOU/UDC, energy service providers, standalone suppliers of limited services, etc.

<u>Alternative 4.3.2 PROS:</u>

(1) attention is focused on determining the necessary equipment and contractual agreements required for participation, and if there are problems in furnishing these to broad numbers of

customer, clearly revealing that it is solving these problems that is required, not debating arbitrary limits on participation;

(2) this alternative provides great opportunities to customers to exercise choice in conjunction with satisfying any necessary conditions.

Alternative 4.3.2 CONS:

(1) CPUC D.95-12-063 would have to be revised to establish the requirements, determine who was permitted to furnish the requirements to the customer, and what oversight over this would be provided by CPUC, UDC, or others; and

(2) It is possible that simple equipment and contractual requirements could be satisfied by more customers than the "system" would be able to accommodate from an unforeseen bottleneck.

4.3.3 Alternative: Contract For Differences As A Mitigating Alternative To Physical Direct Access During The Phase-In Period

In D.95-12-063, the CPUC adopted a policy that allows all customers on January 1, 1998, to enter into price guarantee and other financial hedging arrangements referred to generally as Contract For Differences (CfDs). In pursing such arrangements, customers are free to contract with any retailer willing to take the counter-part risk. The CPUC viewed such arrangements as business transactions, with the terms and conditions left open to the marketplace. Unlike a physical direct access arrangement, CfDs do not require a specific generator to operate, do not require an hourly interval meter (although such may be desirable) and do not require the customer and the retailer to engage in transactions requiring direct settlements by the Scheduling Coordinator.

While CfDs may not be a substitute for physical direct access, they do have the potential for providing customers who are not participating in direct access with an equivalent alternative from a business and financial perspective.

Alternative 4.3.3 PROS:

(1) The use of CfDs and other financial hedging arrangements mitigates the business concerns non-participating customers may have during a direct access phase-in period.

(2) Real-Time, hourly interval meters may not be required to support CfDs.

(3) Available to all customers on 1/1/1998.

(4) Avoids the individual transaction costs of settling load - resource imbalances.

Alternative 4.3.3 CONS:

(1) Since CfDs are generally linked to the PX market clearing price, there are concerns over the PX being a viable spot term market.

(2) Increased difficulty in finding a power supplier willing to enter into a CfD, since the supplier doesn't have the certainty that its physical facility will actually operate.

4.3.4 Final Implementation Plan

The many options described in this section, as well as others that will follow in the remaining sections, should clearly suggest that a final implementation plan does not yet exist. The numerous alternatives identified in this chapter can be selected with some degree of independence, but various combinations cannot be combined. In addition, of course, there are a number of other activities in the Ratesetting Working Group, the CTC process, and at the legislature to ensure that all of the major elements of restructuring come together in a reasonable timeframe and in a coordinated fashion.

The DAWG recommends in Chapter 13 of this report that once the CPUC and FERC have determined the major elements of the revised industry structure, that a detailed implementation plan for direct access be developed for each of the three investor-owned utility services areas. Such an implementation plan would, for example, identify the specific dates and responsible parties for the steps identified in Chapter 3 of this report. While proponents of direct access properly insist on a large degree of uniformity for the requirements of these three plans, it may be appropriate that some elements of a direct access program ought to be configured to suit the circumstances in each existing service area.

Finally, as noted in Chapter 13, a monitoring mechanism must be put in place and utilized to either confirm the phase-in schedule, accelerate it, or retard it according to pre-identified criteria.

Chapter 5. Design of a Phase-In Program

This chapter identifies specific options for implementing the phase-in of eligibility for customer participation in direct access. As discussed in Chapter 4, there is disagreement among the participants in DAWG whether or not a phase-in period is necessary. If the CPUC ultimately adopts a specific phase-in schedule, this chapter describes the multitude of options that are available for designing a phase-in program..

5.1 Assessment of Eligibility Factors

This section reviews various issues of eligibility which may be elements of a phase-in proposal, but are not intrinsic to any one specific phase-in option, e.g. they can be generalized to all phase-in proposals. This section focuses upon factors that address the number of customers that are eligible to participate, i.e. the amount of megawatts of peak demand or the numbers of customers in a specific year.

5.1.1 The Overall Phase-in Descriptor

CPUC D.95-12-063 and D.96-01-006 describe phase-in of direct access, if necessary, in terms of megawatts. While the MOU and these decisions are ambiguous, some interpret this as megawatts of customer peak demand. This is not the only descriptor that can be used to describe phase-in. There are at least three alternatives for describing how direct access can be phased in:

1. peak demand of the customers who participate;
2. energy consumption of the customers who participate; and
3. numbers of customers (number of customer meters) that may participate, either in the aggregate or by various customer classes.

5.1.1.1 Alternative: Peak Demand for a Specified Year

Capacity measured in megawatts has been used in the MOU (sponsored by SCE, CLECA, CMA, IEP, and CCE) and in the CPUC's D.95-12-063 to describe how a phase-in of eligibility for direct access over a period of years might progress. Some parties interpret this capacity as peak demand. Implementation of a peak demand descriptor for phase-in requires that a standardized measurement and a base year within which peak demand for specific customers and for the IOU systems as a whole are referenced.

Alternative 5.1.1.1 PROS:

1. Some parties believe this alternative has precedent in the MOU and CPUC D.95-12-063;

2. Provides a means of mitigating the size of operational and commercial risk during the transition.

3. Concerns over customers which don't know their peak demand is mitigated if load profiles are used.

Alternative 5.1.1.1 CONS:

1. Peak demand will have to be defined in a manner that is compatible with available customer data.

2. Peak demand may raise equity concerns, because peak demand penalizes seasonal customers and customers with poor load factors for no valid reason. Seasonal customers operating a few months of the year will have a measured peak demand very high in comparison to their annual energy. Similarly, poor load factor customers may have high peak demand representing a few hours per week or month compared to their energy consumption.

3. The great majority of customers -- residential and small commercial -- do not have recorded peak demand data.

4. Requires determination of how to measure peak load. For instance, is it coincident, annual average, or individual peak?

5.1.1.2 Alternative: Annualized Energy Consumption

Energy measured as kilowatt-hours could be used as both a per customer and system-wide descriptor for purposes of phase-in of eligibility for direct access. A specific year or time period would have to be determined for use as the reference period.

Alternative 5.1.1.2 PROS:

1. Energy is a universally available descriptor for all customers, whereas Alternative 1's peak demand is only recorded for those non-residential customers with demand charge tariffs;

2. Annual energy is a more fundamental element of revenue collection than is peak demand;

3. Customers with multiple accounts and/or meters per location can be readily aggregated to a single energy descriptor per facility site;

4. Annual energy better captures customers with unusual load factors or seasonal patterns of operation;

5. Although the MOU and D.95-12-063 state megawatts, this descriptor can be easily translated to an annualized energy value.

Alternative 5.1.1.2 CONS:

1. Energy is a descriptor that ranges in several orders of magnitude between largest and smallest customers, and may not reflect the actual costs of developing systems to handle direct access customers, or of the constraints existing systems might impose on participation rates.

5.1.1.3 Alternative: Numbers of Transactions

Most of the rationales for phase-in of eligibility (described in section 4.2, Rationales for Phase-In) have in common the difficulties of dealing with numbers of customers, rather than the size of the load that these customers represent. For example, ten 500 kW commercial customers totaling 5 MW are more complex to deal with than a single 5 MW industrial customer, due to the customer service, data processing, metering and communication system infrastructure, contractual agreement paperwork and other elements of a transaction that takes place on a per customer basis.

Implementation of a transactions-based descriptor would designate a certain percentage of customers within pre-defined customer classes or customer aggregations would be eligible in a given year. This percentage would presumably increase in subsequent years. Among the implementation details to be established are: (1) determine whether a common percentage participation across all customer class is appropriate, (2) how the common participation rate would change through time, and (3) determine how to define transactions.

Alternative 5.1.1.3 PROS:

1. The commonality of the technical limitations reflect concerns about the numbers of customers, rather than megawatts of customer peak demand or energy consumption;

2. More direct linkage of expanded transaction processing capabilities (e.g. expansion of a new computer processing system to facilitate settlement) with the expanded eligibility for direct access; and

3. More straightforward translation of variables and actions being monitored during the phase-in period into go/no-go decisions for expanding direct access participation.

Alternative 5.1.1.3 CONS:

1. Need to resolve the issue of common versus unequal percentage participation by customer classes and/or customer aggregation groupings.

2. Will result in an uneven energy allocation between large and small customers.

3. To the extent that using transactions to limit direct access phase-in results in greater volumes of participation, UDCs may be exposed to greater risk in the event that there are difficulties with market operations during the start up of restructuring.

5.1.1.4 Alternative: Multiple Phase-In Descriptors

Alternatives 5.1.1.1-5.1.1.3 are not necessarily mutually exclusive. Given the geographic variation in billing and network capabilities for the UDCs and other electric supply institutions in conjunction with the uncertainty concerning the geographic distribution of the peak load, annual energy consumption and billing characteristics of the electric customers who will participate in the direct access phase-in, option 5.1.1.4 permits a delay in the determination of the appropriate combination of peak load, annual energy consumption and transactions descriptors until the distribution of characteristics for the direct access phase-in customers has been more clearly specified.

Alternative 5.1.1.4 PROS:

1. Consistent with maximizing the number and variety of electric customers participating in the direct access phase-in.

2. Explicitly recognizes the variation across the UDC's and other electric supply institutions with respect to their respective billing and network capabilities.

Alternative 5.1.1.4 CONS:

1. Greater planning uncertainty for the UDC's and/or other electric supply institutions due to the delay in determining the appropriate set of descriptors until the characteristics of those electric customers participating in the direct access phase-in are revealed.

2. Possible delay in the commencement date for the initial direct access phase-in.

3. Difficult to administer and manage.

4. Potential to further confuse and complicate an already complex issue.

5.1.2 Limitations on Size of Customer Participation

The MOU recommended two limitations on the size of customers loads that could be aggregated: (1) minimum size on individual bilateral contracts, and (2) that aggregation be limited to 8 MW per aggregation group, at least in the original year. These limits were to change over time as indicated in the following table.

Table 1
Suggested Size Constraints in MOU

Eligibility Criteria	1998*	1999	2000	2001	2002
Maximum number of direct access program participants	125	500	****	****	****
Threshold MW limit for individual customer participant**	8	2	0.5	0.1	0.05
MW for multiple customer aggregation participation	***	***	****	****	****
Maximum number of accounts that can be aggregated in each multiple customer aggregation	***	***	****	****	****
Total number of MW available for participation in direct access program	1,800	3,150	4,950	9,000	18,000

* Start date subject to satisfaction of all direct access preconditions.
** Either single site or single customer aggregated sites. Based upon annual peak billing demand..
*** Initial aggregation program to be developed and approved by the CPUC. Aggregated loads are to be limited to 8 MW.
**** To be reevaluated based upon experience during the initial years: it is the parties' intent that the program will continue to expand during the remaining years of the phase-in period.

5.1.2.1 Alternative: Floor on Minimum Size to Participate and Ceiling on Maximum Load to Aggregate

The parties submitting the SCE MOU proposed a bilateral contract minimum size and an aggregation maximum load that is described above in Table 1.

The result of these constraints would be to minimize numbers of customers that could participate, since greater loads per customer for bilateral contracts and maximum loads for aggregation arrangements both work to minimize the numbers of customers that can participate.

Alternative 5.1.2.1 PROS:

1. Fewer numbers of customers in initial years makes scheduling, settlement, billing, ancillary service assignment, data processing and overall systems integration management easier to accomplish for all parties;

2. Greater numbers of large customers can participate in bilateral contract forms of direct access if aggregation is constrained.

3. Mitigates concerns during the early years created by system problems and unavailability;

4. Offers a stable measure for determination of participation levels with very low overhead.

Alternative 5.1.2.1 CONS:

1. Reduction in the numbers of customers that can participate;

2. Elimination of the bilateral contract opportunities for non-aggregated customers below the floor size threshold;

3. Substantial limitations on aggregator efficiency (and cost-effectiveness) by imposing substantial overhead costs on a relatively small number of customers in the early years; some parties believe this would inhibit some aggregators from participating, thereby reducing choice for residential and small business customers; and

4. Substantial barriers to effective participation by small commercial and residential customers (and, some believe, for street lighting and agricultural customers) most likely to require the services of an aggregator to be able to participate in direct access in the early years.

5.1.2.2 Alternative: No Constraints on Size

Several participants interpret the MOU constraints on minimum size and maximum aggregation as jointly reducing the numbers of customers that can participate. Customer transactions processing by the ISO was a concern expressed by utilities during the initial consultation IOUs held with stakeholders. Subsequently, however, WEPEX developed the scheduling coordinator concept which isolates the ISO from most individual customer data. The clearer appreciation for transactions-based constraints raises concerns about establishing minimum size floor for participation using bilateral contracts. From the perspective of the ISO or the UDC, each customer that engages in direct access creates approximately the same transactions-based

paperwork and issues associated with shifting from UDC energy service to becoming simply a distribution customer of the UDC. From the perspective of the scheduling coordinator, greater numbers of customers participating creates additional workload, but whether the costs of this additional work are merited and how fees are charged to recover these costs ought to be a business decision.

Alternative 5.1.2.2 PROS:

1. Greater numbers of customers can participate;

2. Contentious limits are avoided;

3. This alternative is more consistent with maximizing the variety of electric customers participating in the initial direct access phase-in as suggested by the CPUC's representation concept; and

4. Attracts potentially larger range of new market participants to service broad categories of eligible customers.

Alternative 5.1.2.2 CONS:

1. In conjunction with a megawatt peak demand or annual energy phase-in descriptor, this alternative with no constraint on size could reduce numbers of customers participating.

2. Greater number of customers in initial years makes scheduling, settlement, billing, ancillary service assignment, data processing and overall systems integration management harder to accomplish.

3. Use of Scheduling Coordinators shifts complexity but doesn't eliminate it.

5.1.3 Representation from All Customer Classes

CPUC D.95-12-063 requires that all customer classes participate in direct access in some representative manner.. Another equity issue concerns competing businesses where one firm is allowed to participate and others are denied the opportunity to participate for several years. This section raises various alternatives to ensure that equity is maintained.

5.1.3.1 Alternative: Proportional Participation

Application of this alternative requires that an indicator be selected that determines customer class -- tariffs, revenue account groupings of tariffs, SIC code groupings, etc. A set of customer

sectors based on SIC codes frequently used by the CEC for planning purposes separates: (1) residential, (2) commercial buildings, (3) non-building commercial, (4) process industry, (5) assembly industry, (6) mineral/extraction industry, (7) agriculture, (8) major water delivery systems, and (9) streetlighting. Each utility has dozens of specific tariffs, with some variation among utilities about the scope and applicability for each of them.

Customers would submit a form expressing desire to participate to an energy provider, if appropriate; once received it would be classified by customer class, and then held in a pool awaiting examination of a comparison with all such customers. If all customer groups were oversubscribed, but unevenly, then a lottery (for example) would be conducted to select which customers within each customer class were authorized to participate.

5.1.3.1.1. Variant 1A: Participation Proportional to Load

Allocating participation by load yields very different results than allocating by number of customers. This variant allocated participation by energy or peak demand. For example, using annual energy as the system descriptor results in approximately one third to each of broad industrial, commercial, and residential customer classes, on a statewide basis. Specific shares vary by IOU service area.

Alternative 5.1.3.1.1 PROS:

1. There is a greater opportunity for larger customers, who are more likely to be ready and able, to participate in direct access;

2. Aggregators are provided a stimulus since most small customers are perceived to participate through aggregation arrangements.

3. Administration is straightforward.

Alternative 5.1.3.1.1 CONS:

1. The perceived "unfairness" of allowing different degrees of participation among those responding to an "open season" opportunity; and

2. Equal energy (or peak demand) shares implies larger energy (or peak demand) per customer for the industrial and large commercial sectors, even though the costs to the UDC and ISO of this participation are more linked to the number of customers.

5.1.3.1.2. Variant 1B: Participation Proportional to Number of Customers

This variant is similar to the previous one, except number of customers rather than load (energy or peak demand) is used to allocate participation.. Since there are many more small customers than large ones, a customer proportionality approach would place most opportunities in these sectors.

Alternative 5.1.3.1.2 PROS:

1. This option provides the greatest benefit to small customers who are the overwhelming majority of customers of utilities;

2. If the market structure is set up to create a level playing field and the IOUs do not enjoy monopoly powers, many residential aggregators will enter the market. Any company with a billing system and customer service department are possible entrants (i.e. credit card banks, telephone companies, cable companies, etc.).

Alternative 5.1.3.1.2 CONS:

1. Because the overwhelming number of customers are residential and small commercial, this approach would shift actual participation away from the customer classes most interested in and capable of participating. e.g. industrial and large commercial;

2. Transactions-based constraints (meter installation (if needed), bill processing, etc.) would clearly be the technical factors most constraining this option, since this option most emphasizes the small customer.

5.1.3.2 Alternative: Participation by Customer Class Determined as Policy Decision

In this alternative, the numbers of customers participating in the initial year and subsequent years is determined as a matter of policy by the CPUC. Direct determination of these values offers the ability to hear arguments from various perspectives, yet not be bound by a fixed formula that may be inflexible. It may be necessary for this decision to be combined with additional decisions concerning undersubscription and oversubscription by customer class, and protocols for allocating undersubscribed opportunities to other customer classes.

Alternative 5.1.3.2 PROS:

1. Ability to be flexible to create targets based on advance understanding of likely rates of participation; and

2. Ability to select initial participants based on many factors, including success guarantee rationales.

Alternative 5.1.3.2 CONS:

1. Appearance of unfairness by "favoring" one class of customers relative to another for the benefits of direct access; and

2. Administration of such a program might be less "ministerial" and may require greater judgment about likelihood of success for various customer classes, which might raise concerns about bias.

5.1.3.3 Alternative: Participation Proportional to Number of Customers Expressing Interest in Direct Access

This alternative is designed around the proposition that once customers make an expression of interest in participation as a result of an "open season" solicitation, the chances of participation are proportional to those responding, rather than to overall customer loads or counts. This option might require greater customer education efforts in advance as a tradeoff prior to the "open season" period to ensure that customers had some minimal acquaintance with direct access and its opportunities.

Alternative 5.1.3.3 PROS:

1. The opportunities to participate are greatest for those who are knowledgeable and eager to participate;

2. Those customers who make an investment in time and resources to prepare for participation have an increased opportunity to realize a return on this effort;

3. All who respond have an equal chance to participate, increasing sense of a "fair process"; and

4. By being responsive to customer initiative, this alternative encourages innovation and experimentation by customers to become responsible for their own energy futures.

Alternative 5.1.3.3 CONS:

1. Brings into question what is required as "an expression of interest" since small customers will be much less likely to be well informed, may submit needed paperwork without having made a financial commitment, with the result that there may be a substantial "drop out" rate revealed as customers who received authorization, but did not follow through to implement the opportunity;

2. Once the responses to an "open season" solicitation are known, and they are radically disproportionate to underlying customer loads or counts, then little could be done to remedy the outcome; and

3. This alternative may be perceived as unfair to customers who do not learn of direct access until later in the implementation process.

4. Leads to concerns of "stuffing" the ballot box.

5. Time-consuming.

5.1.3.4 Alternative 4: Phase-In Organized by Industry and/or Business Type

If direct access proves to have substantial benefits in reducing energy costs, and if it must be phased in over a lengthy period, then equity concerns of adverse selection among competing firms will become an issue. For example, if energy costs can be reduced 10 percent and phase-in requires five years, then competing grocery stores may be adversely affected if one store is selected in year one while another has to wait for the fifth year. A possible solution to this concern is to schedule opportunities to participate by industry or business type, so that competing firms are provided equal opportunities for participation. In the grocery store example, all grocery stores might be eligible in year three, while all office buildings are eligible in year one. A precise schedule would have to be developed using utility customer records and the SIC code classification of each customer.

Alternative 5.1.3.4 PROS:

(1) Competing firms are not disadvantaged by adverse selection;

(2) Such an industry phase-in might lend itself to one way of developing load profiles for use with small customers that might not be required to have interval meters and communication systems immediately;

Alternative 5.1.3.4 CONS:

(1) Groupings of industries and business would have to be developed, and a schedule for their participation in direct access would require an explicit policy decision;

(2) Specific firms or customers would have to be linked to their industry type, which would expose errors in the IOU SIC classifications of accounts; and

(3) Some firms produce goods or services with multiple SIC codes.

(4) Some might consider it unfair to grant some industries preference over others

5.1.3.5 Alternative: No Customer Participation Rule

If the electric customer education/information process is properly structured, the electric customer interest revelation process is well planned, implemented and monitored and the potential problem of customer oversubscription is adequately addressed, then there is no need for an additional set of customer participation rules in order to achieve the desired distribution of customer participation in the direct access phase-in across the various classes of electric customers.

Alternative 5.1.3.5 PROS:

(1) The reduction in the cost of the direct access phase-in due to the elimination of redundancy.

(2) Consistent with maximizing the number and variety of electric customers participating in the initial direct access phase-in.

(3) Attract new entrants more quickly, accelerate pace of competition and innovation.

Alternative 5.1.3.5 CONS:

1. Increased performance pressure on the electric customer education/information process, electric customer interest revelation process and oversubscription adjustment process.

5.1.4 Availability of Necessary Information to Implement Direct Access

The issue of identifying the necessary information to permit fair and accurate allocation of costs, and the metering and communication systems to collect and deliver this information to those who need it, has been a major concern. Hourly interval metering and electronic communication systems are seen as the ideal means to deliver the necessary information. There is dispute about the investment and operating costs of such systems and whether they may disadvantage small customers. Further, the lead-times for massive installation of these equipment for all direct access customers might restrain access unnecessarily. Finally, since virtual direct access intrinsically requires interval meters (as the CPUC defines this concept in D.95-12-063), the limited ability to install such meters (and perhaps the associated communication systems) also impact the UDC's ability to install this equipment for physical direct access.

Chapter 8 of this report discusses the details of metering and communication systems as they pertain both to direct access and to the role these systems play in the future electricity market for all customers.

This section assesses three broad alternatives for obtaining adequate usage information for Direct Access: (1) universal installation of advanced meters and communication systems for all customers, (2) required use of these systems for participation in direct access, and (3) using load profiles for some small customers to provide an estimate of the information required. This latter alternative has numerous variants which have quite different implications.

5.1.4.1. Alternative: Interval Meters are the Standard Means of Measuring Energy Consumption for all Customers

All customers would be required to have hourly interval metering capability, irrespective of their direct access participation.

Alternative 5.1.4.1 PROS:

(1) Providing all customers with hourly interval metering capability would provide a precise measure for allocating imbalance costs and line losses. This would eliminate risks of cross-subsidies between those customers who have chosen a direct access (or virtual direct access) option, and those customers who have chosen to continue receiving traditional bundled service from the UDC.

(2) All UDC customers would be charged accurate prices for the energy services they consume, just as are direct access customers.

(3) Although there are additional costs associated with installing meters systemwide, those costs are greatly reduced when proceeding in a systematic method;

(4) Full interval metering may be an eventuality. Doing it now mitigates future problems.

Alternative 5.1.4.1 CONS:

(1) Would impose a range of costs for all UDC customers in California as identified in various metering scenarios in Chapter 8. Those customers electing not to take direct access would be, in effect, subsidizing the implementation of direct access for those electing such options.

(2) The time required to adequately retrofit 10 million meters in the State of California may extend beyond the phase-in period identified in D.95-12-063.

(3) Barrier to entry for small customers.

5.1.4.2 Alternative: Interval Meters are the Standard Means of Measuring Energy Consumption for Direct Access (and Virtual Direct Access) Customers

Only those customers participating in any form of direct access or virtual direct access would be required to have hourly interval metering capability.

Alternative 5.1.4.2 PROS:

(1) Provides a precise measure for allocating imbalance costs or line losses. To mitigate risks of cross subsidies between those customers who have chosen direct access (or virtual direct access), and those customers who have chosen to continue receiving traditional bundled service from the UDC, the aggregate load of direct access (and virtual direct access) customers would be subtracted from the total load dispatched by the ISO to determine the appropriate allocation of imbalance costs among direct access customers, and between direct access and traditional service customers.

(2) Hourly meters permit more accurate forecasting than plain consumption meters.

(3) Hourly meters give customers some of the information they need to respond to hourly price signals.

(4) Hourly meters allow more flexible rate options.

Alternative 5.1.4.2 CONS:

(1) The cost of hourly interval metering capability may be uneconomic for small customers and would inhibit significant direct access participation by a large majority of these customers.

(2) The time required to adequately retrofit meters in the State of California for all customers wishing direct access capability may extend beyond the phase-in period identified in D.95-12-063.

5.1.4.3 Alternative: Load Profiles Could Be An Acceptable Measurement Alternative to an Interval Meter for Certain Customers

Although interval meters permit direct customer responses to generation price signals, requiring small customers to pay for the installation and use of an interval meter with electronic

communications capability may prove too expensive for these customers to participate in direct access. DAWG has considered a load profiling option for certain customers as an alternative.

A load profile approximates a customer's pattern of consumption over a given time period. If a load profile can accurately predict a customer's consumption pattern on an hourly basis, then it could serve as a substitute for an hourly interval meter for a customer electing direct access. However, if a load profile used for a direct access customer is inaccurate, then there is difficulty in allocating imbalance costs to those customers because the customer's estimated hourly consumption is different than his actual hourly consumption, and the customer does not have an hourly interval meter to accurately reconcile the difference.

Load profiling deals with measurement using statistical sampling. Ensuring that different aggregators' load responsibility reflects their customers' actual load, as accurately as possible, requires that identifiable differences in load patterns be used to compile the aggregators' load forecasts and settlement requirements. There are two separate types of error that will occur: forecasting error and measurement error. Forecasting error, i.e. imbalances will occur regardless of the accuracy of measurement, i.e., metering.

For load profiling to be a viable substitute for hourly interval metering, there must be a method for forecasting a load profile, measuring actual use, and assigning actual use to each hour of the billing period. The method should not lead to cost-shifting between or within classes or between customers served by different suppliers. Statistically significant load profiling data for a given customer class must be available or obtained via sampling.

Certain data is available today from existing UDC load research programs, the most accurate of which is aggregate sampling of the residential customer class. Additional costs would be incurred to the extent more numerous geographic-specific, industry-specific, or company-specific load profiles were to be developed with an acceptable degree of accuracy. However, use of real-time pricing cannot be accomplished without a real-time meter. The benefits to be achieved through use of load profiling should not be confused by issues dealing with allocation of forecasting errors.

In past uses of load research data (i.e. in rate cases), noticeable time requirements have indeed been present to collect a year of data and then analyze it and present it during construction of a utility's rate case proposal, which is then litigated before the CPUC. For ISO settlements, though, the use of the data would be real time: forecasting would need to be used only for submission of load schedules to the PX and ISO, and data collected in real time would be used for final settlements once monthly meter reads occur. That is, any needed enhancements to the load research sample do not need to be in place for settlements before the time when the data is used.

Under one scenario, what may be required is that automatic meter reading (AMR) be installed for the UDC's existing and enhanced load profiling sample. The results of these reads then could be

posted to enable retailers to improve their day-ahead forecasts of demand of their aggregated population.

Some parties are convinced that the costs of upgrading existing load profile sites with AMR are insignificant when compared to the costs of installing AMR for the entire customer population. Allowing the load research sample to be enhanced prospectively, as needed, could also offer a way to allow aggregators to achieve RTP rate response for their customers: procedures could be developed for segmenting load research strata for customers for whom particular load management devices are installed, without relying on engineering estimates of the devices' effectiveness.

Should load profiling be adopted as a vehicle for direct access, there is a question of establishing an eligibility breakpoint to define which customers may use load profiles. One method is to limit load profiles to customers for whom interval metering is uneconomic. Unfortunately, there is no clear definition of such a breakpoint due to potentially wide disparities in individual customer economic assumptions (e.g. the customers discount rate), the potential or forecast savings due to the direct access deal, any additional customer benefits which accrue due to the meter/communications function (e.g., new approaches to managing the customers energy data), and the disparity of costs among different meter vendors.

However it is clear that the smaller a customer's load and potential dollar savings from direct access the less likely the customer will be willing to pay for new interval metering. For example assuming an average one cent per kwh saving for a 100 kW load customer with a 50% load factor equals an annual savings of $4380 however some interval metering and communications devices might cost as much as $1200 to install (New Hampshire) and then incur monthly charges for in and communications operations. While the costs of interval metering and associated communications are predicted to decrease under large scale deployment such deployment might not begin in 1/1/98 and even if it did so such deployment might not be completed for a number of years. Interval metering could be used to supplement the development of load profiles during the transition. As technologies develop and costs of interval metering fall, it may become a desirable public policy to move toward statewide deployment of interval meters, even if there is a load profiling option in the interim. To reach that conclusion, it will be necessary to demonstrate that the costs of investment in hourly metering technology on a statewide basis would be more than offset by the economic benefits to society of such a policy.

5.1.4.3.1 Variant 3A: Load Profiles As A Transition Step for Small Customers

For the residential, small business, and street lighting (and possibly agricultural) markets, load profiles can be a transition step on the path toward universal interval metering and electronic communication with all customers. If WEPEX prices power differently for peak and off-peak time periods, the price for non-interval metered customers must be based on the load profile. A

dynamic competitive market will result in meters being purchased by those individual consumers and by groups of consumers for whom it is economically justified. As pricing plans and energy efficiency programs are developed in conjunction with meters becoming more affordable, consumers make their own decisions to switch to new meters. Mandating installation of meters before an appropriate design has been achieved could create a significant barrier for residential and small business customers to participate in restructuring and will defeat the CPUC intent that all customer classes benefit from meters.

The design of the PX market and the ISO may impose requirements that are not imposed in other states' restructuring efforts. For example, load profiles are being used currently in pilot programs in New Hampshire and Massachusetts. The distribution utility submits to the grid operator its hourly load forecasts the day ahead, using the load profile data for each customer class. The utility is matching the profile against historic weather patterns and other factors. Each customer's meter continues to be read monthly, and each customer is billed for actual energy used. If there are differences between the forecast and actual usage, that is handled by the aggregator. The UDC and aggregator's responsibilities to provide daily forecasts to the PX and the ISO/SC, respectively, may impose different burdens on customer information.

Alternative 5.1.4.3.1 PROS:

(1) Small customers will be able to participate in direct access on the same or quicker schedule than large customers.

(2) Aggregators interested in serving the small customer markets will come forward if additional costs, like meters, are not imposed on them or their potential customers.

(3) Load profiles are accessible from current utility data.

(4) A universal metering and communication systems can be developed and implemented in an orderly manner, without compromises or wasted investment resulting from hasty installation of equipment incompatible with the universal system.

(5) Load profiling can streamline the billing and metering processes. Sampling facilitates the process of developing load profiles.

(6) Offering load profiling only on a rate schedule basis may not account for the needs of small customers with different load characteristics. It is unrealistic to assume that aggregators' customer populations will have the same mix as customers remaining under UDC service, and since differences in cost-of-service have already been identified between different strata, we must be prepared to reflect those differences in load profiles.[1]

[1] An issue raised in Rate Design phases of both the recent PG&E. and Edison GRCs is whether different residential customers have different load characteristics. In the Edison GRC, a different

Alternative 5.1.4.3.1 CONS:

(1) Load profiling will not improve the accuracy of revenue allocation between or within classes.

(2) Developing initial load profiles from utility load research data will require resources, and maintaining accurate load profiles through installation and updating of a representative sample of residential customers will prove to be a major ongoing effort.

(3) A greater number of more detailed and targeted load profiles for customers at different locations and with different equipment stock and behaviors can result in objections to pre-assigned profiles as customers demand to "game" profiles because of their particular circumstances.

(4) Existing load research represents customer usage patterns under current regulation and in response to current and historical electric prices. Some parties believe that existing load research may be of little use once electric prices are unbundled and customers begin to respond to new price levels and new rate structures.

(5) Customers would not have the incentive they would have with hourly meters to use less energy, because they do not receive a signal in their bill that reflects the actual usage pattern with the knowledge of PX prices;

(6) May create an artificial market subsidy for aggregators who could not otherwise compete;

(7) Provides little incentive for customers using load profiles to obtain an interval meter, thereby reducing potential for meter innovation and cost reduction.

5.1.4.3.2 Variant 3B: Load Profiles Could Be Used For Residential Customers Choosing Direct Access via an Aggregator

In lieu of hourly interval meters, an average load profile could be used by an aggregator to offer direct access to residential customers. The UDC would use this same profile in serving

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customer charge was adopted for multiple-family dwellings because this difference could be established. In PG&E's GRC, TURN is asking for information to be developed to address this cost-of-service issue. Although PG&E did not have data available to address this issue for Test Year 1996, cost-of-service differences may be easily identifiable for other groups within the residential (as well as other) classes.

residential customers who elect traditional bundled service. For non-residential customers choosing direct access, an hourly interval meter would still be required.

Alternative 5.1.4.3.2 PROS:

(1) If the cost of interval metering is prohibitive for large number of residential customers, then a load profiling option would permit these customers to elect direct access.

(2) Since over 80 percent of electric meters in California measure residential customer loads, the use of load profiles as an alternative to hourly interval metering initially would provide an orderly transition to develop an interval metering infrastructure necessary to enable direct access participation by all customer classes.

(3) Historical UDC data suggests that consumption patterns of different residential customers are very similar, even across different geographic regions. Thus, if both the UDC and aggregators of residential load are using the same load profile for forecasting residential demand to the ISO, the magnitude of potential cost shifting or improper allocation of imbalance costs to and from the residential class may be small relative to the costs of installing hourly interval meters.

Alternative 5.1.4.3.2 CONS:

1. The use of load profiles enables choice of supplier, but it does not promote conservation or demand-side management because the customer does not receive hourly price signals on a real-time basis. The residential customer's meter would still be read monthly with pricing signals sent after-the-fact, but this still permits an improvement on current price signals by using a projected load profile to weight PX prices.

2. The use of load profiles may result in cross-subsidization between customer classes and improper allocation of imbalance costs. These results could prove detrimental to smaller customers in particular.

3. Provides little incentive for customers using load profiles to obtain an interval meter, thereby reducing potential for meter innovation and cost reduction.

4. Removing interval metering requirements from residential customers may require other customers to pay increased metering costs due to loss of opportunity for economies of scale.

5.1.4.3.3 Variant 3C: Load Profiles Could Be Used For Other Customer Classes in Addition to Residential.

In lieu of hourly interval meters, a load profile could be used to offer direct access to other customers in addition to residential customers. For example, many of the same difficulties facing residential customers also face small commercial customers, and justify their participation in the use of load profiles.

Alternative 5.1.4.3.3 PROS:

(1) If the cost of interval metering is prohibitive for large number of residential customers, then it may also be prohibitive for small commercial customers.

(2) Some customers operate on known timeclock patterns, which have been used in ratemaking calculations at the CPUC, and for those customers installation of unnecessary metering equipment would be avoided.

Alternative 5.1.4.3.3 CONS:

1. The variation in load profiles between different non-residential customers within a given class is significantly greater than between different residential customers. For example, within the small commercial class, a baker and dry-cleaner will have very different load profiles. Similar analogies can be represented for larger commercial and industrial customers. Thus, load profiles will be inaccurate for these customer classes without significant new sampling data, and the risks of cost-shifting and improper allocation of imbalance costs would be significant.

2. Because there are so many variations in small commercial load profiles, the costs of load profile development and administration for hundreds of business-specific load profiles will be substantial and will likely be borne by consumers in those classes.

3. If commercial customers have the choice between interval meters and load profiles, customers who suspect that they have poorer than average load profiles would presumably choose to use the profile and shift costs to all other customers without interval meters by increasing the proportion of unallocated consumption of power purchased at peak times.

5.1.4.3.4 Variant 3D: Load Profiles Could Be Used In Conjunction with Upstream Metering.

The concept of upstream metering is to use metering points between a set of individual customers and the transmission system. This may involve installing an interval meter at a transformer serving three customers, or at a substation serving fifty customers. If a specific load pattern can be isolated by upstream metering, which may involve one or more interval meters, then direct responsibility for this demand pattern can be attributed to those who use and should pay for this power "downstream".

A set of customers could agree to have their power provided by an aggregator who uses upstream metering. The usage of those who do not elect direct access and remain on traditional bundled service would be subtracted (based on a load profile) from the upstream interval meter load. The aggregator would then be directly responsible for settlement of accounts on loads scheduled and power used based on the upstream interval meter data.

Alternative 5.1.4.3.4 PROS:

(1) Use of upstream interval meters in conjunction with load profiling would improve overall measurement accuracy of load consumption for the load downstream of the interval meter and facilitate appropriate allocation of imbalance costs to those customers.

(2) Use of upstream metering will ensure that customers pay for the load shape they cause and for the settlements they create.

(3) Without upstream metering, forecasted load profiles may increase skewed price signals and will not reflect market prices.

(4) T&D interface metering, a form of upstream metering, may improve overall understanding of power flows through a system. It could improve allocation of imbalance costs and may have operational benefits for UDCs and their customers.

Alternative 5.1.4.3.4 CONS:

(1) Aggregators are likely to develop a customer base that is geographically dispersed, while upstream metering is most effective if aggregation is concentrated geographically downstream of such a interval meter.

(2) Upstream interval metering would be one of the more expensive methods of minimizing accounting error. At the transformer level, it requires primary voltage meters which today could cost $15,000-$20,000 each.

(3) Substantial costs (perhaps in the magnitude of tens of $ millions) would be required to install revenue quality potential transformers and current transformers at upstream locations.

(4). Distribution system design does not lend itself well to metering entire circuits or loads at the substation level. These systems are often "looped", with multiple delivery points to ensure reliability. As a result, a meter at a transformer or substation may capture more or less load than it was intended to. This could result in the very cost shifting that the upstream meter was intending to avoid, unless upstream metering is implemented at the T&D interface.

(5) Upstream metering would require the development of a separate load profile for each upstream metering point, so that there is no cross subsidy between metering points and so that all customers downstream of a metering point receive the same load profile.

5.1.4.3.5 Variant 3E: Load Profiles Could Be Used for Customers Below a Specific Size Threshold

One means of establishing who should have access to load profiles is to set a load size threshold. Various size thresholds have been discussed by the Working Group, but the most developed proposal suggests a breakpoint of 100 kW for the initial years of direct access. Customers under this breakpoint of 100 kW would automatically be allowed to use load profiling as an alternative to interval metering. (Of course if the customer wished to install interval metering, that would be a customer option.). However customers over a 100 kW load would be required to install interval metering as a pre-condition for direct access. This 100 kW limit would be a per meter limit not specifically a per customer limit. For example, a customer might have two or three meters at a site whose total load was above 100 kW but if the per meter load at individual meters is below 100 kW then the customer would be allowed to use load profiles for each meter. This in turn may involve, in some situations, different load profiles for different meters at the same site. For reference, the New Hampshire Public Utilities Commission has, in its Retail Competition Pilot Program allowed customers of any size to load profile, while the Director General of Electricity Supply for England and Wales has chosen a 100 kW boundary for load profiling.

Alternative 5.1.4.3.5 PROS:

(1) Provides smaller customers the opportunity to participate in the direct access opportunity.

(2) Clearly delineates a boundary beyond which interval metering is required.

(3) Maintains the customer option of choosing interval metering.

(4) Sets a high enough level for kW load for interval metering monitoring eligibility should be made easier than under designations of e.g. 20 kW.

Alternative 5.1.4.3.5 CONS:

(1) There is no 100 kW and above designation in any existing utility rate schedule (SDG&E's cut-off point is 20 kW, generally the cut-off point for PG&E and SCE is for load above 500 kW). The Restructuring decision requires interval metering for large commercial and industrial customers, at a breakpoint of about 20 kW (D.95-12-063, p. 78)

(2) This may lead to some problems in classifying customers as 100 kW and above. However kwh consumption should be a reasonable guideline that the utility can use in conjunction with the customer's industrial classification.

(3) It may be that an "average" load profile for some small commercial and agricultural rate schedules cannot capture the wide diversity of load in these schedules, that is few customers are actually the "average". The implication of this is that a retailer could use load profiles for some of these types of customers to the financial disadvantage of other market participants. This problem, could, however, be ameliorated by further load profile studies.

(4) Load shape characteristics for non-residential customers are sufficiently diverse so as to make the use of load profiles problematic.

5.2 Solicitation and Selection Procedures for Direct Access

This section addresses specific solicitation and selection procedures for direct access customers (and virtual direct access customers) *during any phase-in period.*

5.2.1 Open Season Solicitation of Participation

Notice of a forthcoming "open season" opportunity for potential providers or retailers to solicit interest in participation is part of the general education associated with electric industry restructuring in general, and direct access in specific. Following closely upon these education materials must come an actual open season opportunity itself in the parties contact customers to solicit their interest in participation. This open season should occur in the early fall of 1997, if there is a phase-in period.

A CPUC-sanctioned consent form to release data combined with a statement of intent to engage in direct access is likely to be submitted by the customer (or through the energy provider) to determine whether customer class mis-representation and oversubscription protocols must be invoked. Consent forms may also require that the customer acknowledge their responsibility for payment of CTC charges and public goods surcharges. What data is included within this release is reviewed in detail in Section 10 of this report. Whether some data determined to be non-sensitive is released for all customers is a separate issue(also discussed in Chapter 10). Consent may include release of certain energy consumption data necessary for retailers to develop a customer-specific proposal.

Various options exist to determine who will conduct this initial customer contact and what the customer contact should include. These options address different approaches to safeguard customer privacy and the use of customer information to be released to providers, retailers and aggregators to develop marketing plans.

The result of the options discussed below is a signed statement of intent to participate, perhaps even a conditional contract between customer and provider. In the event of oversubscription, whether measured by peak load, annual energy usage, or numbers of customers or transactions, some customers may not be able to participate initially.

5.2.1.1. UDC Solicitations

5.2.1.1.1 Alternative 1A: IOU Solicitations of Interest Followed by Marketer Contacts with Interested Customers

This alternative requires a two step process. (The process could be different for residential and business customers, depending on how access to customer data is resolved for various customer groups.) In this alternative the IOU (or an agent representing the IOU) solicits an indication of interest in electing direct access. The customer signs an expression of interest, which probably includes a consent form authorizing release of certain IOU-held customer information to certified providers, retailers, or aggregators. The scope of this information release would probably have to be authorized by the CPUC. All customers signing approval forms would have their data provided to eligible retailers. Marketers then make specific customer contacts with this pool of interested customers and attempt to obtain signups and agreements to participate.

Alternative 5.2.1.1.1 PROS:

(1) customer personal privacy or business trade secrets are a dominant consideration, and no customer's individual data is released for direct access marketing purposes without prior approval;

(2) only those customers initially interested in direct access will be targeted by providers;

(3) phased eligibility allows a limited set of customers to be contacted, making more manageable the process of handling customer inquiries and responses;

(4) concerns from customers being marketed to would be reduced; and

(5) customers can exercise choice.

Alternative 5.2.1.1.1 CONS:

(1) if data release is limited to customers who self-select on the basis of a UDC education program alone, marketers will not be able to rely on customer-specific information to tailor marketing efforts to the remaining customers. As a result, marketing plans for these customers will be generalized and unfocused.

(2) some business customers may consider an unauthorized release of customer-specific data to violate laws related to release of trade secret or commercially sensitive data;

(3) total costs of the solicitation process, including both direct costs of marketing as well as unmeasured costs of "aggravation" to customers for which customer data would have caused a retailer to screen them out, will be increased compared to alternative approaches; and

(4) because UDCs could exercise control over merits of direct access programs, the CPUC will have to review and/or directly sanction IOU open season solicitation materials to ensure that no bias toward IOU affiliates or against direct access in general is present in these materials.

(5) People who learn about it only in step 2 will feel it's unfair.

5.2.1.1.2 Alternative 1B: Solicitations of Interest by a Neutral Agent Followed by Marketer Contacts with Interested Customers

This alternative is really a minor variant on the previous alternative. What is different is that a neutral agent, selected either by the CPUC or the IOU, conducts the initial inquiry about customer interest. The IOU would have to either provide customer data to the neutral agent, or process information on its behalf, to allow the agent to conduct mailings, develop customer databases, etc.

Alternative 5.2.1.1.2 PROS:

(1) compared to the previous alternative relying upon the IOU/UDC, a neutral agent would be perceived as unbiased.

Alternative 5.2.1.1.2 CONS:

(1) such an agent would have to be selected and its costs recouped by either the IOU/UDCs or the CPUC directly;

(2) including yet another party in the handling of customer records and data may be more costly.

5.2.1.2 Provider Solicitations of Intent to Participate

If there is no UDC open season customer notification, as described in the previous section, electricity providers will necessarily make the initial contact with customers to solicit interest in direct access. Marketers can collect written authorization (or, alternatively, verbal authorization which has been third party verified or where the UDC has been given a 15 day period following

receipt of notification of change of carrier as with FCC rules for telecommunications) from customers to either acquire customer usage information or to switch their service.

Two variants of this single stage approach are reviewed below; the difference between them involves whether the provider is informed in advance of solicitations with customer-specific information or whether the marketer approaches the customer "blind."

5.2.1.2.1 Variant 2A: Providers Are Given Customer Data Prior to Solicitations of Intent to Participate

In this alternative, providers that want to contact customers directly as part of their marketing efforts are provided access to UDC customer energy usage information. Access to relevant customer information (or at least the subset which is eligible in the period in question) permits each retailer or aggregator to target only customers which fit within their marketing plan. [See Chapter 10 for further discussion of customer data release issues].

Alternative 5.2.1.2.1 PROS:

(1) customer-specific consumption and other data allows customer-specific benefits to be computed by the potential provider and included within initial customer contact materials, potentially leading to greater customer participation;

(2) no need for the CPUC to review/sanction IOU materials to avoid affiliate bias;

(3) universal customer data permits many more marketer contacts with customers than in the alternative two-step processes;

(4) elapsed time of the open season process is reduced compared to Alternative 1;

(5) marketer costs are reduced by the ability to target customers compatible with their marketing plans compared to alternative 2B; and

(6) customer contacts where customer usage patterns are incompatible with marketer plans are minimized compared to alternative 2B.

Alternative 5.2.1.2.1 CONS:

(1) CPUC D.95-12-063 restriction on release of customer data without prior customer consent must be revised;

(2) some customers will be concerned that their privacy or trade secrets were revealed against their wishes;

(3) larger total number of dissatisfied customers not interested in participation in direct access compared to alternative 1;

(4) some consumers will be concerned that they are being hassled, which is why they typically do not allow information to be released about themselves; and

(5) greater likelihood of customers being misinformed and mislead if the UDC or neutral agent has not contacted the customer earlier, before the marketing process begins.

5.2.1.2.2 Variant 2B: Providers Are Not Given Customer Data Prior to Solicitations of Intent to Participate

As in the previous variant of this alternative, the provider is permitted to directly contact all customers eligible for direct access without the previous contact of the utility. In this variant, however, the provider has no customer-specific data to use in developing marketing plans or in selecting specific customers for marketing efforts. In effect, no targeted marketing is possible.

Alternative 5.2.1.2.2 PROS:

(1) compared to Alternative 2A, no customer data would released and fewer issues of possible customer privacy or trade secret violations would be encountered.

Alternative 5.2.1.2.2 CONS:

(1) larger total number of dissatisfied customers not interested in participation in direct access compared to alternative 1;

(2) some consumers will be concerned that they are being hassled;

(3) greater likelihood, begins compared to Alternative 1, of customers being misinformed and misled if the UDC or neutral agent does not contact the customer before the marketing process begins;

(4) marketers will not have data on the variation in customer usage patterns to use in developing marketing plans;

(5) marketers will not have customer-specific data to target specific customers which fit their marketing plans, so more "wasted" customer contacts compared to Alternative 2A;

(6) marketers must rely on general promotional literature which increases their costs compared to alternative 2A, and increases the "aggravation"; and

(7) uninformed marketing is likely to lead to decreased percentages of customers electing to participate in direct access relative to Alternative 2A.

5.2.2 Rationing of Participation

If there is a phased limit on participation, and when agreed-upon customer class representation targets are missed or oversubscription protocols must be invoked, then requests to participate must be processed to select a reduced set of authorized customers within a short time period. A predetermined, agreed-upon rationing or allocation scheme must be used that meets appropriate tests of fairness, speed of implementation, and certainty. What considerations should be used in devising fair oversubscription mechanisms for customers that are not equal in size, knowledge, or capabilities? In this section alternatives of using lotteries, selecting first-come-first served, and or pro-rata allocation to all applicants are discussed.

5.2.2.1 Alternative: Lottery

When too many persons wish to participate in a limited activity, lotteries can be used to select the "winners." This approach is feasible within the context of selection for participation in direct access, but creates additional nuances in this setting. For example, if eligibility is defined using customer classes to ensure representative participation, does this mean that lotteries are used within each customer class? What would happen if some customer classes were oversubscribed but others were not? Are the original proportions of eligibility reallocated among the classes to better reflect interest in participation?

Alternative 5.2.2.1 PROS:

(1) Because of their randomness with everyone having an equal chance to "win", lotteries may be perceived as "fair" by some;

(2) Easily administered.

Alternative 5.2.2.1 CONS:

(1) Some participants perceive a lack of fairness in the randomness of lotteries, which could advantage some businesses over others;

(2) Does not acknowledge details of a proposed direct access arrangement, including probability of following through to implementation;

(3) Probably has to be implemented within segmented strata to ensure each customer class is contained in final selection.

5.2.2.2 Alternative: First-Come, First-Served

This alternative presumes that an open season period requires that a request to participate will be filed with the IOU/UDC and that this organization can date/time stamp requests in the order that they are received. Requests to participate would be processed on a first-come, first-served basis until the cumulative limit of peak demand load, energy, or number of transactions appropriate to each customer class have been reached. Once this limit is reached, then no additional participation would be permitted until the subsequent open season period.

Alternative 5.2.2.2 PROS:

(1) Those customers/generation service suppliers that can quickly submit requests for participation will be more likely to be authorized to participate, which could be viewed as fair since these customers took the time and energy to be well informed and ready to participate;

Alternative 5.2.2.2 CONS:

(1) Those customers/generation service providers who have already negotiated conditional arrangements would be provided a substantial advantage over other customers;

(2) Bilateral contract customers would likely receive major advantages compared to aggregation customers, since bilateral contract customers are much more likely to have developed conditional arrangements beforehand than are aggregation customers;

(3) Depending on the number of people who want to sign up, this could be inherently unfair because the result could border on randomness, depending on whether a customer hit an open phone line at the right time to get through or made it into the right stack of mail as it was sorted;

(4) First come, first served does not provide a level playing field for all potential direct access customers, potentially advantaging one business over another similar business;

(5) Rewards quickness, not efficiency; and

(6) May need to deem all requests received in a certain window as "tied" requests

5.2.2.3 Alternative: Pro-Rata Among Applicants

Most parties have understood participation in direct access to mean that once a customer submits a request to engage in direct access, and that request is authorized through whatever selection/rationing process may be necessary, then the customer is no longer a responsibility of the UDC for energy supply purposes. The customer and his provider(s) have the benefits and costs of participation in the direct access market for generation services, either through bilateral contracts or through aggregation.

Some parties have described phase-in proposals where customers would request partial levels of their load that might participate in direct access, and undersubscription or oversubscription within a class of customers might lead to revisions in the proportion of an individual customer's loads that were authorized to participate. These customers would, in effect, remain an energy customer of the UDC while simultaneously becoming an energy customer of a private provider through a bilateral contract or an aggregation arrangement. There are two variations that will be described below with separate advantages and disadvantages.

5.2.2.3.1 Variant 3A: Partial Participation in Direct Access With Floor on Load Participating

Partial participation in direct access splits a customers load into portions serviced by direct access and portions served through the UDC by the PX. For example, partial participation implies that a hypothetical 12 MW peak demand customer might be authorized to participate in a bilateral contract with 5 MW of load, while the remaining 7 MW of load would be supplied by the UDC through the Power Exchange. In this variant, the customer is allowed to bid all or any portion of his entire 12 MW load and condition his participation on at least a portion of the bid being accepted. If the customer was not authorized enough load to satisfy his conditions, then the customer would drop out of that stage of the phase-in process, presumably to try again in a subsequent phase.

Alternative 5.2.2.3.1 PROS:

(1) The advantage of partial participation is that more customers are enabled to participate in direct access, especially during periods in which very limited quantities of load are authorized to participate relative to the demand to participate; and

(2) Some believe this alternative would not advantage one business over another.

(3) Provides customers with the ability to acquire power from more than one supplier, a market condition which is desirable; and

(4) Provides opportunity to test operational and commercial systems involving multiple suppliers.

(5) Some believe that imbalance settlements could be easily handled if the rationale for allocations is established in advance.

Alternative 5.2.2.3.1 CONS:

(1) pro-rata allocations of participation which fail the customer's minimum participation threshold may lead to "return" of that initial customer's allocation back to the pool for possible reallocation to other hopefuls, which would create additional complications for the selection process (some believe this could be handled by a computer algorithm);

(2) some parties believe that partial customers would continue to impose cost burdens and responsibilities for energy demand on the bundled-service customers of the UDC;

(3) some parties believe that when customers' loads vary from the forecast level, it is possible that the UDC would be viewed as the entity wholly responsible for the variations, not the direct access component, thus imposing all imbalance costs and forecasting uncertainty burdens on the customers of the UDC;

(4) imbalance costs caused by a partial customer could be shifted to other UDC customers;

(5) some believe that settlement for imbalance costs becomes much more complex, especially if the customer's generation supplier serves multiple end-use customers, and even worse if they have different scheduling coordinators;

(6) customer's and energy provider's abilities to engage in multi-year bilateral contracts are damaged by the uncertainty of the level of customer loads that will be authorized to participate from one year to the next;

5.2.2.3.2 Variant 3B: Partial Participation in Direct Access Without Floor on Load Participating

In this variant, a hypothetical customer with 12 MW total load is allowed to bid his entire 12 MW load but is not allowed to condition his participation on the whole load being accepted. The customer would have to accept as a condition for eligibility that only a portion of his total load would be accepted, and that there might be strong probability that his load would actually be split between direct access and the PX/UDC. Some parties have suggested that such customers ought to be allowed to purchase from the PX through their direct access provider, thus reducing the role of the UDC.

Alternative 5.2.2.3.2 PROS:

(1) compared to variant 3A, even more customers are enabled to participate in direct access, especially during periods in which very limited quantities of load are authorized to participate relative to the demand to participate; and

(2) some believe partial participation could avoid giving one business an advantage over another

Alternative 5.2.2.3.2 CONS:

(1) customers and their suppliers might be forced to undertake expensive overhead costs for the contractual and implementation costs of direct access with only small portion of the expected benefits which justified the deal;

(2) partial customers potentially impose cost burdens and responsibilities for energy demand on the customers of the UDC just like in Alternative 3A;

(3) when customers loads vary from the forecast level, it is possible that the UDC would be viewed as the entity wholly responsible for the variations, not the direct access component, thus imposing all imbalance costs and forecasting uncertainty burdens on the UDC;

(4) customer's and energy provider's abilities to engage in multi-year bilateral contracts are damaged by the uncertainty of the level of customer loads that will be authorized to participate from one year to the next;

(5) some believe that, as in Alternative 3A, there are ambiguities about settling imbalances when a generator in a bilateral contract also serves other direct access customers, and even worse ones if these contracts go through different scheduling coordinators;

(6) residential customers loads could not be split since they are too small to justify two energy supply relationships.

5.2.2.4 Alternative: Modified First-Come, First-Served with Lottery Tie-Breaker

If the electric customer education/information process is properly structured and the electric customer interest revelation process is well planned, implemented and monitored, then the first-come, first-served rationing process can achieve any targeted level of fairness provided that a lottery is used when necessary to break ties among electric customers in the first- come, first-served queue.

Alternative 5.2.2.4 PROS:

(1) Captures the benefits of both the rationing by queuing and lottery alternatives.

(2) Minimizes if not eliminates the downside risks associated with the rationing by queuing or lottery alternatives.

Alternative 5.2.2.4 CONS:

(1) Increased performance pressure on the electric customer education/information process and the electric customer interest revelation process.

(2) Does not maximize the number and variety of electric customers.

(3) Some perceive lotteries as random and unfair and as creating winners and losers, advantaging one business over another.

(4) Simply rewards speed.

5.2.3 Undersubscription

Should a particular phase of direct access eligibility be undersubscribed, then clearly all of the applicants should be authorized to participate. However, how to "take advantage" of the remaining capacity is not self-evident. At least two cases can be distinguished, and the solutions in these cases may be different. First, presuming that some reservation for capacity exists for customer classes, if undersubscription occurs within a specific customer class, but not for the total of all customers classes, then reallocation of capacity may be feasible. Second, if undersubscription occurs for the total of all classes, then no ready pool of applicants exists. If there were no reservation of capacity by customer class, then the first case could not occur, but the dilemma of the second case would still be relevant. Each of these cases will be briefly described.

5.2.3.1 Undersubscription Within Customer Classes Alone

Presuming that there is a system of reservation of capacity for direct access (whether described by annual energy, peak demand, or number of customers is not important), then the result of the open season solicitation is that some customer classes are undersubscribed and some classes are oversubscribed. Two alternatives exist: (1) reallocate the spare capacity from undersubscribed classes to oversubscribed classes, (2) provide another round of open season solicitation limited to the undersubscribed classes, or (3) do nothing to make use of the spare capacity.

5.2.3.1.1 Alternative: Reallocate the Spare Capacity from Undersubscribed Classes to Oversubscribed Classes

The response to mixed oversubscription and undersubscription among the various customer classes would be to shift the undersubscribed capacity to the oversubscribed customer classes in some manner. Several variants on how to do this are possible: (1) achieve proportional oversubscription in all classes, (2) accept all applications in the original undersubscribed classes and shift spare capacity so that each oversubscribed class achieves an equivalent improvement, and (3) accept all applications in the original undersubscribed classes and shift spare capacity so that each oversubscribed class achieves an equal level of oversubscription.

Alternative 5.2.3.1.1 PROS:

(1) customers who made a good faith effort to participate in direct access are accommodated;

(2) more customers are accommodated;

(3) customers taking the initiative to respond to opportunities are rewarded for their efforts, in contrast to the continued "handholding" that Alternatives 2 and 3 might suggest.

Alternative 5.2.3.1.1 CONS:

(1) some minor additional costs might be required;

(2) original goals of customer class representation are not maintained; and

(3) the variations in how to perform reallocation might require regulatory oversight and quick decision-making by the CPUC.

5.2.3.1.2 Alternative: Provide Another Round of Open Season Solicitation Limited to the Undersubscribed Classes

This alternative is predicated on maintaining the balance of customer class representation that was built into the original program design. A targeted customer education and solicitation process would be employed to obtain additional elections from the undersubscribed customer classes. To implement targeted marketing might require special processing of customer records, selective inclusion of materials in UDC bills, and other narrowcasting techniques that might not be required in the original effort for this phase of eligibility.

Alternative 5.2.3.1.2 PROS:

(1) alternative education and marketing efforts might discover the "hot button" that elicits strong customer response.

Alternative 5.2.3.1.2 CONS:

(1) undersubscription might be the appropriate customer response if costs of participation exceed expected benefits; therefore to continue to urge participation would be wasting money from various parties, and might entice some customers to make the wrong choice;

(2) customers from classes that are oversubscribed would be denied an opportunity to participate simply to achieve balanced representation of all classes that might be incompatible with the facts;

(3) additional costs would be incurred with no clear understanding of the benefits; and

(4) the decision-making process to commence and then to implement a second round might lead to additional elapsed time before authorizations were sent to prospective participants.

5.2.3.1.3 Alternative: Do Nothing to Make Use of the Spare Capacity

This alternative suggests that the results of the open season solicitation are accepted, and that no secondary efforts are conducted to reallocate "unused" capacity from undersubscribed customers classes to oversubscribed customer classes.

Alternative 5.2.3.1.3 PROS:

(1) The advantages of the "do nothing" alternative include:(1) any delays associated with reallocation consideration, its implementation, and other adjustments are avoided; and

(2) Any costs associated with reallocation are avoided.

Alternative 5.2.3.1.3 CONS:

(1) customers who responded to open season solicitations in good faith could be accommodated, but cost consciousness denied them this opportunity;

(2) balanced representation from various customer classes might be more difficult to achieve.

(3) May slow development of direct access competitive market.

5.2.3.2 Undersubscription Across All Customer Classes

Overall undersubscription signifies a mismatch between the assumptions used to design a phase-in program and the interests of customers. Many possible factors might lead to such an outcome, and before implementing one or the other of the following alternatives, it would be highly

desirable to make an attempt to understand why this situation has occurred. For example, if phase-in design presumes a major customer education effort, which was not forthcoming or of a smaller scale than anticipated, one would expect fewer customers to elect this choice than were planned. Knowing this, one might not throw open direct access to all customers, because an excessive level of response might occur compared to the capabilities of the market and UDC customer systems to handle. Instead, additional education with another round of open season solicitation might be logical. On the other hand, if such an undersubscription can be traced to customer hesitancy to commit to overhead, transactions costs with very small energy services cost savings, then perhaps one would throw out phase-in restrictions and let the market evolve as market participants determined how to reduce costs. Undersubscription may also mean that the market structure is not correct, and there are not enough new participants serving customers' needs. In summary, these alternatives might not be mutually exclusive, but are indicative of a family of potential responses which might be employed depending upon an assessment of the reasons for overall undersubscription.

5.2.3.2.1 Alternative: Provide Another Round of Open Season Solicitation

Faced with overall undersubscription, and armed with an assessment that suggests the underlying costs of participation are smaller than the benefits, one might imagine that another round of open season solicitation, perhaps preceded by additional customer education, would be logical.

Alternative 5.2.3.2.1 PROS:

(1) more customers have the opportunity to determine whether this choice makes sense for them;

(2) UDC and provider expenses allocated directly to direct access participants would be recovered by a larger number, thus reducing per unit costs.

Alternative 5.2.3.2.1 CONS:

(1) potential delays in implementation of this round of phase-in eligibility, thus disadvantaging customers who did respond in a timely manner;

(2) additional expenses that might not stimulate much additional customer interest; and

(3) this alternative fosters the "its a specific result we want" attitude, rather than allowing customers the freedom to make their own choices, even if they are not the best ones.

5.2.3.2.1.1 Variant on Alternative 1: Provide another round of open season solicitation with an eligibility cap

Under this variant, ability to participate after a second round of solicitation would be subject to a ceiling equaling the maximum number of participants allowed in the then-scheduled next phase of direct access phase-in. For example, if the megawatt limitations of D.95-12-063 remain in place, the total megawatts, eligible after the second open season would be 3150 MWs, and increase of 1350 from the first open season. (See D.95-12-063, p. 220.)

Alternative 5.2.3.2.1.1 PROS:

(1) more customers have the opportunity to determine whether this choice makes sense for them;

(2) UDC and provider expenses allocated directly to direct access participants would be recovered by a larger number, thus reducing per unit costs.

(3) helps control phase-in problems if the response to the second open season is substantial.

Alternative 5.2.3.2.1.1 CONS:

(1) potential delays in implementation of this round of phase-in eligibility, thus disadvantaging customers who did respond in a timely manner;

(2) additional expenses that might not stimulate much additional customer interest; and

(3) this alternative fosters the "its a specific result we want" attitude, rather than allowing customers the freedom to make their own choices, even if they are not the best ones.

(4) if a second round of open season solicitation leads to oversubscription, customer disappointment and resentment may result.

5.2.3.2.2 Alternative: Do Nothing

In the face of undersubscription, no special action is taken to depart from the pre-planned phase-in schedule.

Alternative 5.2.3.2.2 PROS:

(1) eliminates the possibility of making a major mistake, which would cause large customer dissatisfaction and complaints;

(2) additional costs of another round of open season solicitation, processing of requests, verification of balanced representation, and possible oversubscription selection processes would be avoided.

Alternative 5.2.3.2.2 CONS:

(1) if some customers could have benefited from greater exposure to direct access education and would have elected to participate, then at least one year's benefits would be foregone;

5.2.3.2.3 Alternative 3: Terminate Phase-In Requirements and Allow All Customers to Participate In Direct Access

This alternative would be exercised by terminating all elements of the direct access program that were directly associated with monitoring phase-in, determining eligibility, conducting open season solicitations, and operating selection processes. This would reduce costs for the CPUC and other regulatory agencies that might play a role in the oversight of direct access, the UDCs who would be administering various customer education and verification activities, and energy service providers that had to conform to specified open season protocols.

Alternative 5.2.3.2.3 PROS:

(1) any customers holding back from concerns about regulatory agency meddling with terms and conditions of their "deals" might be encouraged to elect direct access; and

(2) costs associated with conducting a program with phase-in, eligibility and selection processes would be reduced, if not eliminated.

Alternative 5.2.3.2.3 CONS:

(1) misdiagnosis of the reason for the shortfall in responses to a particular customer education, marketing, and open season solicitation might fail to reveal large interest in direct access that previous efforts failed to detect. Terminating all phase-in requirements might lead to new marketing efforts that "hit the button" and stimulated far more response than the market participants and UDC customer systems could support. This might lead to the problems that "success guarantees" were trying to avoid.

5.2.4 Continuity of Participation in Phase-In of Direct Access

Some parties have raised the concern that under stretched out direct access phase-in, that ability to participate in an early year of direct access ought to provide no special benefit concerning eligibility to participate in a subsequent year. For example, if an industrial customer of 15 MW was able to participate in 1998's initial year of direct access because the customer was selected in a lottery to resolve oversubscription for the industrial class, the customer would be compelled to request participation in 1999's open season process, and accept the results of the lottery, which might mean the customer was not selected in 1999. The implication of this approach is that direct access contracts could only be a single year duration while phase-in was underway. This issue only exists if pro-rata allocation is not used, and a method of accept/deny is used instead.

Two alternatives are described below that address whether each year of a phase-in program is independent, or whether once selected, always selected.

5.2.4.1 Alternative: Participation is Limited to a Single Year and Participation in a Prior Year Provides No Greater Right to Selection in a Subsequent Year

This alternative presumes that each year is independent of subsequent years for the duration of a phase-in program. Selection in 1998 confers no greater rights or probability of selection in 1999, or other post-1998 years if direct access phase-in is lengthy.

Alternative 5.2.4.1 PROS:

(1) more customers are enabled to participate during a period of limited opportunity;

(2) the process may be perceived as more fair if those who selected the first year are not allowed to "lock up" available energy for the long term, leaving later participants to negotiate over what is left over;

(3) if rationing is implemented by lottery, does not provide an excessive windfall due to "luck";

(4) reduces complaints of customers who may not be selected for several years.

Alternative 5.2.4.1 CONS:

(1) those customers who have been advocating for direct access, and who anticipate being able to participate, believe they will have the opportunities to make their own choices through bilateral contracts; some customers selected in one year believe they will be able to continue in subsequent years, especially if total volume of participation is rising through time;

(2) some combinations of customer interest in participation (low initial year, high subsequent year) could lead to lower probability of selection in subsequent year, especially if eligibility increases slowly;

(3) creates a barrier against direct access compared to UDC energy service from the PX; and

(4) necessary marketing, equipment installation, and UDC activities for each customer participating might be poorly utilized if they were not able to be used for multi-year periods.

(5) limits direct access contracts to one year, limiting negotiating flexibility of power supply and price. This might inhibit some providers from participating.

(6) removes any incentive for development of endpoint technology innovations or development of enhanced energy services until after 2003 by significantly increasing the risk of stranded investment for all market participants

(7) will inevitably result in increased costs for each year as a result of mandated consumer "churn."

5.2.4.2 Alternative: Once Selected, Always Selected

Some customers who have followed restructuring and anticipate that they will be direct access participants through bilateral contracts believe that once they are selected, they will always be selected. Some may have already negotiated long term contracts, with conditional exercise clauses, with marketers on this premise. Having to undergo selection repeatedly is probably highly undesirable, since it increases ex ante participation costs in general and for those which participate.

Alternative 5.2.4.2 PROS:

(1) lower costs for participation of those selected by the avoiding periodic selection costs, and amortizing overhead costs over multiple years;

(2) lower costs for the program in general by reduced marketing efforts for suppliers with longer term bilateral contracts of aggregation agreements;

(3) avoidance of some inevitable customer complaints to the CPUC and UDCs from customers who failed to be selected in subsequent years who were selected in prior years; and

(4) better direct access negotiating flexibility and continuity of supply and price.

Alternative 5.2.4.2 CONS:

(1) fewer total numbers of customers that are enabled to participate, especially with long phase-in programs;

(2) the program may be perceived as unfair if the result of "once selected, always selected" is to allow those selected the first year to "lock up" long term energy supplies, leaving later participants to negotiate for what is left; and

(3) might encourage some customers to attempt selection in the initial year, thus causing a greater proportion of applicants to be rejected or greater proration if that approach is used.

5.2.5 Selection to Participate Notification

Once the open season has been completed, and especially if a rationing scheme has had to be deployed to achieve customer class representation requirements or to constrain overall participation to agreed upon volumes, then a notification of authorization to participate must be issued to the customer and/or the energy provider. This will set in motion various contractual arrangements concerning new tariffs, metering/communication system responsibilities, bill arrangements, etc. that will characterize participation in direct access. Once these are in place, then additional physical actions associated with UDC data base changes, perhaps physical meter/communication system installation, and other time-intensive steps will be required to be completed before direct access service can actually commence on January 1, 1998.

5.2.6 Customer Selection of Energy Provider

This section discusses how an individual or business customer can elect direct access, particularly when the individual or business entity has multiple accounts and meter sites. There are three alternatives identified.

5.2.6.1 Alternative: An individual customer must elect direct access for all of its electric accounts or none at all.

A customer would be required to take all of its energy requirements for all of its meters and various locations from either the UDC or from a Direct Access retailer including itself under self-service approaches. If the UDC is providing its energy, 100% of it would come from the Power Exchange during the 5-year transition period. If a retailer provides its energy, the customer would simply identify that retailer when it notifies the UDC that it is taking direct access service. The suppliers would be responsible for procuring all the customer's energy needs at all locations.

Alternative 5.2.6.1 PROS:

(1) Simplicity -- this approach minimizes the opportunities for settlement disputes.

Alternative 5.2.6.1 CONS:

(1) This approach requires a great deal of coordination among customers, the UDC, and third parties as to what constitutes a customer. An individual corporate entity maybe a single business with multiple meters/accounts at multiple locations.

(2) In this event, a customer's choice may be limited if all the customer meters must be served by a single energy supplier. This would also limit its ability to disaggregate and re-aggregate its loads to obtain potentially better deals.

(3) If particular meters are not specified by a customer, and the customer's combined account load is more than that provided by the energy supplier's contractual requirement, the resulting shortfall is picked up by the UDC. If there are no restrictions on frequency of designating whether a meter is Direct Access, the customer (and supplier) can game the system by "switching the meters" identified as Direct Access delivery locations to achieve maximum savings and limited supplier obligations, all at the risk of the UDC's core customers and the Power Exchange.

5.2.6.2 Alternative: An individual customer may elect direct access for some of its accounts

A customer specifies to the UDC which meter or meters would be supplied by a retailer via Direct Access. Each customer meter has a separate account. All meters not so specified will continue to receive energy through the UDC from the Power Exchange.

Alternative 5.2.6.2 PROS:

1. This alternative provides customer increased flexibility over Alternative 1. Also, it is consistent with the historical way electric utilities have viewed customers; that is, a meter has historically been viewed as a customer independent of the fact that a particular business or other electricity purchasing organization may have several meters, perhaps at several locations. Compared to Alternative 1, this option requires less work on the part of the UDC in figuring out which accounts are associated with which customers. Very large loads that wish to take some energy through Direct Access could obtain a second meter.

Alternative 5.2.6.2 CONS:

1. A customer might contract with a retailer to provide energy to its high load factor meters and impose its poor load factor meters on the UDC, which could result in increasing peak prices and imbalance costs to other UDC customers. The magnitude of the impacts are likely much smaller than in Alternative 3.

5.2.6.3 Alternative: An individual customer may elect direct access for a portion of a specific meter's load and rely on the UDC as energy supplier for the balance of the specific meter load.

A customer can specify a portion of the load served by one or several meters to be provided by a retailer through Direct Access, with the remaining portion of the load at that meter provided by the UDC.

Alternative 5.2.6.3 PROS:

1. This provides the customer maximum flexibility in purchasing energy. For large industrials with very large loads on one meter, it would limit the choices if they could not have the UDC and Direct Access suppliers provide portions of the load on a single meter. More choices will create greater market forces. To eliminate the UDC as a provider and a player in the procurement decision process is contrary to the spirit of the restructuring process. There will be a great deal of uncertainty, especially during the initial stages with the restructuring process. Many customers would be hesitant to leave their UDC completely and dive into this new and potentially volatile market. The option of being able to retain a block of one's load (which could represent critical process) with the UDC and experimenting in the free market with the balance would be a very attractive and competitive alternative.

2. Some parties agree that "partial requirements" customers on load profile templates who swing on the UDC could cause greater imbalances than "full requirements" customers, but believe that this is a function of load profiling rather than direct access, and that the total cost shift to UDC customers will not increase if only part of the load is served via Direct Access.

Alternative 5.2.6.3 CONS:

1. This alternative could greatly complicate the settlement process and could result in "gaming" if a rationale is not specified for allocating imbalances between suppliers. Even if customers had interval meters, it would be impossible to determine which portion of any imbalances was associated with Direct Access contracts and which portion was associated with UDC/PX load (though some believe it would be fair to allocate the imbalances on a pro rata basis) . Those without interval meters (i.e., those on load profile templates) could very likely cause greater imbalances than other customers in the class, but would be allocated the class average imbalance, thereby shifting costs to non-Direct Access customers that do not have interval meters. "Partial Requirements" customers on load profile templates who swing on the UDC could cause greater imbalances than "full requirements" customers because (A) peak loads are more difficult to forecast, and (B) imbalances are more likely to occur during peak periods. People tend to under-forecast during peak periods.

2. If a customer can contract for base-load power with a third party and rely on the UDC for the swing load, cost shifting will also result. (Cost shifting is not a problem if the customer takes its swing load from the PX through an aggregator, not through the UDC.) Presumably, "partial requirements" customers would be served on the UDC rate schedule appropriate for their entire usage and their installed metering technology; i.e., many would likely be served from industrial schedules. Industrial schedules contain separate peak, partial peak, and off-peak energy charges. These energy charges will be determined by dividing the average Power Exchange price for the peak period by the KWH used in that period. To the extent that "partial requirements" customers use more energy during the highest priced hours of the peak period than other customers, they will shift costs to other customers.

3. To the extent that "partial requirements" customers' peak loads increase the Power Exchange price and/or the on-peak energy charges, there is less room under a rate cap scenario to collect CTCs.

4. This alternative would substantially increase the UDC billing effort for this type of customer. It is not clear whether usage from a single meter can be billed from essentially two separate tariffs B one a Direct Access tariff and the other a bundled tariff. The customer would be required to bear those extra costs so as not to impose them on other UDC customers.

5. Other Cons are identified in Section 5.2.2.3.1 of this report.

5.3 Notification of Change in Provider

This section discusses the procedures for a customer to change its election of energy provider to and from the UDC. The discussion below refers to requirements only when the UDC is one of the energy suppliers involved. (Note: Chapter 9 discusses the billing and credit issues surrounding these choices.)

5.3.1 Written Notice Requirements To Exit Or Return To Bundled UDC Service

Each customer would be required to sign an agreement for each meter (or multiple meters) specifying that it is electing Direct Access and that the UDC is not responsible for procuring and coordinating the delivery of its energy supplies including forecasting and balance responsibility. This Direct Access election agreement would also specify the customer's obligation to continue to pay federal and state approved charges including T&D, CTC, and Public Goods.

The election must be signed by the customer. In order to prevent misunderstandings, a potential retailer cannot execute this election on behalf of the customer. This provision eliminates potential slamming abuses by unscrupulous retailers.

As part of the Direct Access election agreement, the customer would agree to provide the UDC with the following:

Customer name and address to verify the metering location for Direct Access service; and
Any information necessary to enable the UDC to calculate a monthly bill. (The question of who bills whom for what is discussed in Chapter 9.)

Any Direct Access customer wishing to return to UDC procurement service is free to do so without any special tariff condition. The customer must notify the UDC and direct access service provider in writing that it wishes to return to the UDC procurement service. All monies owed the direct access service provider should be paid (unless subject to a formal complaint) before the UDC initiates service.

5.3.2 Timing Requirements To Exit Or Return To Bundled UDC Service

Upon the UDC's receipt of the executed Direct Access election agreement, the customer would begin receiving Direct Access service once any new metering and communication equipment is installed, and the UDC has an opportunity to finalize a meter read, switch billing records, and modify its load forecast. The timing of this change is either::

A. The period of time coincident with the existing meter reading and billing schedule, perhaps up to five weeks, or

B. A shorter time for telemetry-based systems tied to the time necessary to make account adjustments, or

C. A shorter time based on a special reading and processing service provided at customer expense.

For customers returning to bundled UDC service, UDC service would be effective on the schedule which accommodates the circumstances in A, B, and C above, or the date specified by the customer, whichever is later. The customer is obligated to provide its previous energy supplier with a copy of the notice to the UDC that they are returning to bundled UDC service. It may be useful to have a CPUC-approved standard form that would contain entries for all the information necessary to facilitate the customer's return to UDC procurement service.

5.3.2.1 Alternative: Customers returning to UDC procurement service must remain with that service a minimum of one year.

Upon returning to bundled UDC service, the customer will be required to take UDC procured services for a minimum period of one year regardless of any open season selection that may occur

during that time period. (Switching from bundled UDC service to Direct Access can only be done during an open season . See Section 5.2.2.) Switching between Direct Access suppliers can be done at any time provided the billing party receives 7 days notice of the change and the information necessary to bill the customer.

Alternative 5.3.2.1 PROS:

(1) Prevents customers from using the UDC for potential "gaming" of seasonal pricing, which could adversely impact bundled full-service customers and add administrative burden to the UDC.

Alternative 5.3.2.1 CONS:

(1) Inhibiting customers in this fashion may also inhibit the market from developing.

5.3.2.2 Alternative: Customers returning to UDC procurement service would be required to take UDC-procured services at least until the next open season.

Pros and Cons are the same as Alternative 5.3.2.1 above.

5.3.3. Limits On Service Changes During The Phase-In Period

5.3.3.1. Alternative: Customers could change between UDC bundled service and direct access service at the beginning of any normal billing cycle.

Customers can change between UDC and Direct Access service at the beginning of any billing cycle provided that notice is given 7 days in advance. If a customer elected to change service in the middle of a billing cycle, it can do so by paying appropriate administrative service fees. It is felt that the marketplace will control the frequency of switching back and forth and there is no need to place an artificial constraint on a switching period.

Alternative 5.3.3.1 PROS:

1. Maximum flexibility for the customer.

Alternative 5.3.3.1 CONS:

1. If customers switch faster than UDC systems can react, either (A) customers will receive poor service, or (B) UDCs will upgrade their systems and pass along the costs.

2. It may be difficult to evaluate restructuring process initially for lack of continuity.

3. Possible difficulties in information exchange between energy supplier UDC (and biller if not the UDC) for efficient transition.

4. Market may not be developed enough to control switching in transition period.

5. Leads to bothersome calls by aggregators and suppliers all through the year rather than a specified period.

5.3.3.2. Alternative: Customers can change between Direct Access and UDC bundled service upon 30 days notice.

Customers can change between Direct Access and bundled UDC service upon 30 days' notice. However, customer may only return to Direct Access status during an electric open season with a minimum requirement of one year's UDC procurement. Service from the new provider will commence on the customer's next regularly scheduled meter read date.

Alternative 5.3.3.2 PROS:

1. Better customer service, lower UDC system costs. Customers could still switch between energy suppliers if their first choice proves unfortunate. Ensures more stability for all parties.

2. See Section 5.2.2 for discussion on benefits of open season.

Alternative 5.3.3.2 CONS:

1. Less flexible for customers.

5.3.3.3. Alternative: Customers must either have selected direct access service or UDC bundled service for a minimum of 12 months before switching either to and from UDC bundled service.

A customer may only switch from direct access service to UDC bundled service, or from UDC bundled service to direct access service, after taking its supply service from the provider for a minimum of 12 months. After that minimum 12 month requirement, service from the new provider will commence at the customer's next regularly scheduled meter read, provided that notice is given to all affected parties within 7 days of that meter read date.

A customer whose supplier has defaulted on its service arrangements with that customer would be exempt from the 12 month switching limit.

Alternative 5.3.3.3 PROS:

(1) In the event that the generation market is not mature enough to meet the capacity needs of all Californians, this would allow the PX to better plan for these needs.

Alternative 5.3.3.3 CONS:

(1) Difficult to enforce. If a direct access customer's supplier does not deliver its power obligation, electrically, the customer will automatically "lean" on the PX and the UDC (presuming the UDC load forecast is based on its total load less the direct access customer requirements).

(2) Inhibiting customers in this fashion may also inhibit the market from developing.

Chapter 6. Market Rules

This chapter deals with the subject of rules to govern the activities of various participants in the competitive electric services marketplace. Closely related to the subject of this chapter is the set of consumer principles that was developed in meetings of the DAWG Consumer Protection and Education Subgroup, which are discussed in Chapter 2 of this Report. The subject of access to customer-specific information, which is a major area for market rules, is given its own chapter, Chapter 7.

Section 6.1 discusses in general terms the activities requiring market rules, the entities to be subject to rules, and possible mechanisms and authorities for enforcing rules. Section 6.2 reviews some legal points regarding CPUC jurisdiction over competitive retail electric service providers, reviews CPUC regulation of competitive local telephone providers, and describes some analogous rules from other states.

The next three sections discuss the need for specific rules to govern the activities of basic types of participants in California's retail electric services marketplace. Section 6.3 discusses rules to govern Scheduling Coordinators (SCs); Section 6.4 discusses Utility Distribution Companies (UDCs); and Section 6.5 discusses rules for competitive retailers.

The last two sections deal with two more narrow subjects. Section 6.6 discusses franchise fees and user charges, and Section 6.7 discusses master-metered customers, particularly mobilehome park residents. The reader is also directed to Appendix D of this report, which provides some supplementary informative material on the topics of this chapter.

6.1 Statement of the Problem and Overview of Options

The problem is to determine what rules should govern the competitive provision of retail electric service and how those rules should be enforced. Addressing this problem entails specifying the activities and entities to which the rules should apply, the content of the rules, and the means of enforcing the rules, including designation of responsible enforcement authorities and a process for resolving complaints. A competitive market for electric services cannot and should not be a pure laissez-faire environment. Ensuring healthy competition entails specifying certain activities to be required of market participants and other activities to be limited or prohibited. Beyond these constraints, which will be the focus of market rules, the underlying supposition is that "everything not explicitly prohibited is permitted," unless, of course, new problems arise and the rules need to be modified.

The term "market rules" should be read as synonymous with the terms "standards of conduct" and "codes of conduct," of which examples drawn from other contexts are discussed in this

chapter for illustrative purposes. These terms should all be read as generic, with no implied distinctions about how the rules should be developed or enforced. The discussion in this chapter aims both to recognize applicable rules that already exist and to identify needs for and suggest new rules.

6.1.1 Activities Requiring Market Rules

The market rules discussed in this chapter are intended to govern three principal areas: system operations (technical needs to ensure safety, reliability and management of system-wide effects); fair competition (to prevent market power abuses, minimize barriers to entry and facilitate sustainable, efficient competition); and, consumer protection (fair dealing and protection of privacy). This chapter does not try to address activities that are under the jurisdiction of the Federal Energy Regulatory Commission (FERC). California market rules may, however, apply to entities regulated by the FERC to the extent those entities also engage in activities subject to state jurisdiction. In particular, consideration should be given to regulation of market structure at the retail level in a fashion analogous to FERC's regulation of market structure for wholesale providers.

6.1.1.1 System Operations

The interconnected nature of the electricity delivery system requires the new marketplace to be more integrated than other competitive markets. In particular, there is a need for market rules to minimize the likelihood that the action of any given party may have unanticipated effects that impair safety and reliability. These rules should enhance the ability of providers to fulfill the terms of direct access contracts without imposing costs on other parties, including customers of the Power Exchange. Means to achieve this objective include registration and licensing to ensure the technical capabilities of parties.

Rules to safeguard system operations should include a means to compensate parties adversely affected to recover any costs imposed on them as a consequence of a party's failure to perform appropriately. Although the ISO settlement process is being designed to assign such costs to responsible parties, it may be advisable to devise a complementary mechanism for collecting the necessary funds and distributing them to appropriate parties. Some kind of financial assurance such as bonding may be required for this purpose.

6.1.1.2 Fair Competition

The objective of market rules in this area is to facilitate a fair, efficient competitive marketplace, in which no competitor enjoys unfair advantages. Specific rules should address, among other things: equal access by all retailers to customer information, both public and non-public (some parties assert that this should apply only to public information), and to other strategic assets; unfair or anticompetitive business practices; market power abuses at the retail level (analogous to

FERC's concern about wholesale market power); appropriate separation of regulated monopolies from their competitive affiliates; and, dispute resolution and penalties for violations.

Although some generic statutes and regulations exist and are applicable, such as state and federal anti-trust laws and unfair business practices statutes, there need to be some industry-specific rules to ensure a marketplace that is competitive and fair. We will examine standards or codes of conduct from other states and other types of utilities that address these issues. Some parties believe that similar standards need to be developed for California's electric services marketplace to ensure that the unregulated, competitive affiliates of regulated utilities or UDCs do not enjoy unfair advantages as a result of their affiliation.

6.1.1.3 Consumer Protection

The objective of market rules in this area is to ensure that behavior of firms towards customers — for example, marketing practices, required disclosure, uses of customer information — conforms to certain standards of fair dealing and respects customer rights to privacy. Specific rules should address, among other things: marketing practices (such as telemarketing, misleading advertising, slamming); redlining and other discriminatory practices; required disclosure of certain firm- and service-specific information; standard formats for contracts and bills; procedures for terminating service and for changing providers; uses and dissemination of personal customer information (see Chapter 7 for a full treatment of this topic); multi-lingual requirements; and, an accessible, prompt and fair process for complaint resolution. Consumer protection regulation must apply equally to all market participants, including UDCs and competitive providers.

6.1.2 Entities to be Subject to Market Rules

As subsequent sections will show, positions differ about which of the above categories of rules should apply to which types of entities. For example, parties seem to agree that rules to ensure system operations should apply to all entities whose actions may affect the electric system, in particular, to all competing retail electric service providers, including generation suppliers and aggregators. In contrast, parties do not agree on the extent to which private, competitive firms should be subject to industry-specific rules dealing with competitive behavior or contracts with customers. Some parties argue for a more laissez-faire approach, while others argue that market rules to ensure fair competition should be broadly applied, even to include energy efficiency providers because efficiency competes in the generation market. Consumer protection rules, some parties assert, should apply to all firms that deal directly with retail consumers. Finally, some parties have indicated a need for rules to govern relations between competitive firms and regulated monopolies, to ensure a fair competitive playing field with no special advantages for monopoly affiliates.

This chapter will take a broad approach in its inquiry and address the needs for rules for all types of market participants, describing opposing positions where they have been expressed by

the contributors to this chapter. To minimize ambiguity, we try to separate questions of the content of market rules from questions of applicability. Thus we use the general terms "retailers" and "providers" interchangeably to refer to the entire class of competitive firms that will be subject to certain market rules, without always specifying which entities are included in that class. Then, as the discussion requires, we indicate where specific types of entities are the focus.

6.1.3 Mechanisms for Enforcing Market Rules

The following sections discuss different mechanisms for enforcing apprpriate behavior on the part of market participants. The selection of mechanisms provided here is neither prescriptive nor exhaustive, nor should they be seen as either redundant or mutually exclusive.

6.1.3.1 Registration, Certification or Accreditation of Retail Providers

Registration requires would-be market participants to disclose relevant information to a public entity, which would make that information available to the public. For example, under proposed Rule 11.07 of the Massachusetts Department of Public Utilities, a generation provider seeking to do business in Massachusetts would have to disclose: (a) its legal name and all names under which it conducts business; (b) its business address; (c) information concerning the organization structure, e.g., if a corporation, a copy of its Articles of Incorporation and the name, address and title of each officer and director, plus proof that the corporation is in good standing; (d) proof that the entity is authorized to do business in the state (for example, if the entity is incorporated out-of-state); (e) name, title and telephone number of the customer service person; (f) name, title and telephone number of the regulatory contact person; (g) description of the nature of business being conducted; and (h) evidence of financial soundness such as surety bonds. All registered market participants would be required to update their information quarterly and whenever there is a material change. As the market evolves, additional information requirements could be imposed. In addition, the information and the applicants would be subject to audit.

Some parties caution that this process should be as ministerial as possible, like California's checklist for new telecommunications resellers. Additionally, quarterly updates create unnecessary paperwork. Some parties suggest as an alternative that any changes in contact people should be reported as they occur, while other information may be provided in an annual report.

Certification (or accreditation) is similar to registration, but instead of being under the authority of a public agency it would be implemented by an industry watchdog organization. Certification gives the industry a chance to supervise itself, with the understanding that government could impose a more heavy-handed approach if the industry fails to do an adequate job.

6.1.3.2 Licensing

Many industries and businesses whose activities can affect public health and safety are required to have licenses. It is illegal, for example, to operate a hospital or nursing home without a license from the State Department of Health Services. Like registration, licensing requires that providers submit detailed information and that they meet very specific criteria. In addition, many licensed businesses are closely regulated and subject to inspection. In the event that a business violates a regulatory requirement, its license may be revoked. In some cases the employees of a licensed entity must have individual professional licenses, many of which are issued by the Department of Consumer Affairs.

6.1.3.3 Bonding and Other Financial Assurances

A bonding requirement is often imposed in conjunction with another approach such as licensing or certification. The amount of the bond should be set high enough to compensate those parties adversely affected by the firm's failure to perform. Requiring a bond (like a performance bond on a construction project) or a letter of credit has at least two beneficial consequences. First, the firm's ability to obtain a bond or a letter of credit is a proof of its financial soundness. Second, the bond provides a source of funds that could be used to compensate parties adversely affected by a provider's non-performance.

6.1.3.4 Continuing Market Oversight

Continuing market oversight entails the periodic or continuous disclosure of information by the firm about its activities and its condition. The information would be disclosed to a public entity that would review it for conformance with required standards. The oversight entity may be required to keep the information confidential, unless it is required as evidence in investigating a potential problem. The oversight entity would have the authority to order a full audit of the firm if the disclosed information suggested a possible violation. Such market oversight is sometimes referred to as "light-handed regulation," and implicitly contains the potential for heavy-handed regulation if firms do not cooperate with disclosure requirements or other problems occur.

6.1.4 Enforcing Authorities

The following types of authority are not mutually exclusive alternatives. In fact, they often represent different levels of enforcement that complement each other.

The problem of specifying the enforcing authority is highly intertwined with the problem of specifying the entities to which the rules should apply. For example, some parties argue against industry-specific market rules that govern contractual arrangements between private parties, asserting that civil enforcement and general public authorities such as the State Department of

Consumer Affairs and the Attorney General are adequate to enforce appropriate business practices and to provide recourse for breach of contract or violations of general business codes.

6.1.4.1 Private Civil Enforcement Through the Courts

The court system is a channel through which private parties may press grievances they have against other parties and seek redress. Breach of contract is one area where parties commonly seek resolution of disputes on a case-by-case basis. Private enforcement through the courts can be costly, however, so in practice it may not be a feasible option for smaller claimants. Whether it is prohibitively expensive has not yet been determined. At the same time, since the courts are widely used to settle disputes in most areas of commerce, this mechanisms is relatively familiar and well-understood.

6.1.4.2 Private Civil Enforcement Through ADR

Alternative dispute resolution (ADR) has become more popular in recent years. There are numerous types of ADR, the most common being early neutral evaluation of a dispute to try to settle it before litigation commences or progresses; mediation of a dispute; and arbitration of a dispute. ADR can be (but is not always) less costly than civil enforcement through courts. ADR very likely has a place in the new market in several areas, including disputes between customers and UDC's or energy providers, customers and scheduling coordinators, suppliers and scheduling coordinators, and scheduling coordinators and the ISO or PX. The Commission should carefully examine ADR to determine where it may be beneficial to enact regulations requiring its use in the new market.

6.1.4.3 Public Civil Enforcement -- General Authorities

General authorities that will likely play an enforcement role in the restructured energy services market will include the Department of Justice and the Federal Trade Commission at the federal level, and the Attorney General and State Department of Consumer Affairs at the state level. These agencies can issue injunctions and/or impose fines on firms that violate their market rules. Appendix D presents some of the California business statutes that would apply to retail electric service providers.

6.1.4.4 Public Civil Enforcement -- Industry-Specific Regulatory Agencies

Industry-specific regulatory agencies typically use some combination of the four mechanisms mentioned above -- registration, licensing, bonding and continuing oversight. To give a specific example, some parties suggest that rate regulation under the PU Code be continued for retailers unless they can demonstrate that they do not possess market power. In this way the CPUC would be the enforcement agency for ensuring a competitive market structure. This regulatory function would entail requiring all retailers to show that they do not have market power in retail

electric supply in order to obtain exemption from CPUC rate regulation (as FERC does with power marketers at the wholesale level). The CPUC would have continuing oversight to ensure that changing circumstances do not justify re-regulation of rates for retailers previously determined to be competitive.

6.1.4.5 Self Enforcement via Industry or Stakeholder Associations

Self enforcement is an appealing idea and can work in certain contexts. A watchdog agency under the authority of an industry association or a stakeholder association (which may have members and directors besides the firms that make up the industry) can impose sanctions for violation of its rules, but it cannot legally enforce the rules. For example, when an association maintains a "list of approved providers" that it releases to potential customers, it can remove from that list any member firm that violates the industry codes of conduct. If it enacts a certification program, it can rescind the certification of an offending member. These actions may be effective deterrents of undesirable business practices. In some cases an association may require member firms to post a bond that can be used to compensate a party injured by a firm's actions.

6.2 Regulatory Authority, Existing Statutes and Examples from Other Contexts

6.2.1 CPUC Jurisdiction Over "Electrical Corporations"

Does the CPUC have jurisdiction, under existing California law, over all competitive providers of retail electric service? The following discussion begins to address this question by reference to CPUC authority as expressed in the California Public Utilities Code.

The CPUC has jurisdiction over "electrical corporations" as defined by California Public Utilities Code § 218: "'Electrical corporation' includes every corporation or person owning, controlling, operating, or managing any electric plant for compensation within this state . . ." (For the purposes of this discussion, the current statutory exemptions are ignored.) "Electric plant" is defined to include "all real estate, fixtures and personal property owned, controlled, operated, or managed in connection with or to facilitate the production, generation, transmission, delivery, or furnishing of electricity for light, heat, or power, ..." Cal. Pub. Util. Code § 217. "Electrical corporations" are defined to be "public utilities." Cal. Pub. Util. Code § 216.

It is not clear whether new types of generation providers, such as aggregators and marketers, who may not be directly in the business of generating electricity, would be "electrical corporations" as intended by § 218. Since they would be using their assets "in connection with or to facilitate the production, generation, transmission, delivery, or furnishing or electricity for light, heat, or power" as per § 217, logic would suggest that these new providers could be held to be "electrical corporations" and hence subject under this Code to CPUC jurisdiction. At the same time, these new electric retailers would not likely be considered "public utilities" as per § 216, so a new type

of "electrical corporation" may need to be defined in the Code, one that is not considered a public utility for certain purposes such as ratemaking. Draft legislation to that effect is, at the time of this report, under consideration by Senator Peace's committee in the California Legislature. In the next section we discuss the CPUC Decision D. 95-07-054 on local telephone competition, which suggests an anology for the electric industry.

In determining the legal basis for CPUC jurisdiction over retailers, some issues to be addressed include the following.

1- Should all retail generation providers be subject to uniform regulation?

2- If so, should all retail generation providers be defined as "electrical corporations" and therefore subject to CPUC regulation, or should they be expressly exempted from the definition of "electrical corporation?"

If all retail providers are defined as "electrical corporations" subject to CPUC jurisdiction, the CPUC may have the discretion to exempt them from ratemaking and other strictures of the PU Code that would normally apply to public utilities, if these retailers can demonstrate to the CPUC that they are competitive, i.e., that they do not possess market power in retail energy markets. If the CPUC does not have this discretion, then statutory changes to the PU Code may be necessary. Appendix D Section D.1 provides a list of Code sections that would probably not apply to competitive retailers in the new marketplace, including an extended discussion of the power of eminent domain.

Alternatively, generation providers could be explicitly excluded from the definition of "electrical corporation" and therefore not subject to CPUC regulation as the Code presently stands. This would not mean that they would be completely unregulated. Competitive generation providers, like participants in other competitive markets, would be subject to various statutes and regulations that govern the marketplace. For example, the California Cartwright Act, California Buiness and Professions Code §§ 16600 et seq., codifies California's anti-trust law and prohibits various unfair trade practices (see Section 7.1.3 of this chapter). Market participants would also be subject, of course, to federal anti-trust laws and would face civil liability for breach of contract and tort causes of action.

Whether generation suppliers are defined as electrical corporations or not, there will likely be a need for some new industry-specific market rules, as Sections 7.3 to 7.5 should demonstrate. In particular, the facts that electric service is a necessity and its provision has serious system-wide considerations comprise a strong rationale for such rules. The question then is whether to change the California Public Utilities Code to extend CPUC authority to competitive retail providers, perhaps by statutorily defining a new entity called a "non-utility electrical corporation," or to vest enforcement of industry-specific market rules in another public agency. The proponents of widely applicable market rules, as discussed in Sections 7.2 and 7.5, express a preference for the

CPUC as the enforcing agency. Again, telecommunications decision D. 95-07-054 provides an instructive example (see next section).

3- If the answer to question 1 is no, what kinds of distinctions should market rules make? Should the rules distinguish between firms that operate assets to physically produce electricity from those that do not? Should there be specific rules for generation providers affiliated with regulated utilities or utility distribution companies (UDCs)? Should there be specific rules for each type of generation provider, i.e., generators, marketers and aggregators? Should there be specific rules for generation providers that pursue physical bilateral contracts, in contrast to ones that operate exclusively through the Power Exchange?

The answers to the last set of questions will vary depending on the specific types of activities to be regulated. As regards system operations, each specific type of entity will undoubtedly need some specific rules. But in the areas of fair competition and consumer protection, marketplace participants would probably be best served by common rules for all parties.

6.2.2 CPUC Regulation of Local Telephone Competition

CPUC Decision D. 95-07-054 (as revised by D. 95-12-056) establishes rules to govern local competition in telecommunications service. The decision authorizes prospective *competitive local carriers* (CLCs, which need not operate any telephone wires or other facilities required for providing telephone service) to request certificates of public convenience and necessity (CPCNs) to provide local exchange service under a set of specified rules. There are at least three elements of this decision that suggest analogies for the electric services industry: 1, the way the scope of CPUC authority over CLCs was determined; 2, use of the CPCN as the registration mechanism; and 3, the content of the market rules.

6.2.2.1 Determining the Scope of CPUC Jurisdiction

In D. 95-07-054 the CPUC defines the scope of its rules to cover all providers of a specific type of service. "These interim rules apply to the provision of local exchange telecommunications services by CLCs, and where applicable, LECs [the local exchange carriers Pacific Bell and GTE California, the existing monopolies]" [D. 95-07-054, Appendix A, p. 2]

In a discussion of the "Applicability of the CPUC Rules to Wireless Services" the CPUC makes clear that "the key distinction [in deciding whether a carrier shall be subject to CPUC rules] is what service is being offered by the carrier in question. ... We do not intend to restrict the type of technology a carrier may employ to offer local service. ... The adopted rules shall apply to any CLC irrespective of whether it uses wireline, wireless, or both to provide a service that is equivalent to the current wireline basic telephone service." [D. 95-07-054, pp. 23-24]

In making the above assertion the CPUC interprets quite broadly the definition of "telephone corporation" as stated in Public Utilities Code § 234: "'Telephone corporation' includes every corporation or person owning, controlling, operating or managing any telephone line for compensation within this state." The reader should note that this definition is much narrower than the definition of "electrical corporation" in Public Utilities Code § 218, since the former seems to hinge upon a specific type of asset, the telephone line, whereas the latter encompasses "all real estate, fixtures and personal property" (see Section 6.2.1).

Thus, direct investment in telecommunications infrastructure is not a prerequisite for a telephone company to be classified as a CLC. Indeed, the rules distinguish two types of CLCs:

"Facilities-based CLCs are those which directly own, control, operate, or manage conduits, ducts, poles, wires, cables, instruments, switches, appurtenances, or appliances in connection with or to facilitate communications within the local exchange portion of the public switched network.

"Nonfacilities-based CLCs [also called 'resale CLCs'] are those which do not directly own, control, operate, or manage conduits, ducts, poles, wires, cables, instruments, switches, appurtenances, or appliances in connection with or to facilitate communications within the local exchange portion of the public switched network." [D. 95-07-054, Appendix A, p. 3]

6.2.2.2 The Certificate of Public Convenience and Necessity (CPCN)

The CPCN is traditionally a permit that a regulated utility must obtain from the CPUC prior to undertaking a major infrastructure project [see Public Utilities Code § 1001]. The process for obtaining a CPCN requires showing that the project is in the public interest, that it will comply with all applicable regulations, and that it will not interfere with the operation of any nearby or competing utility. Because of this essential association with construction of physical facilities, the CPCN as a certification vehicle for CLCs is a departure from its traditional use, especially when applied to nonfacilities-based or resale CLCs.

To obtain a CPCN, a prospective CLC must demonstrate "the requisite managerial qualifications, financial resources, and technical competence to provide local exchange telecommunications service." [D. 95-07-054, Appendix A, p. 4] The decision then goes on to specify financial and other standards, including cash-on-hand requirements, and states that "All information furnished to the Commission for purposes of compliance with this requirement will be available for public inspection or made public, except in cases where a showing is made of a compelling need to protect it as private or proprietary information."

6.2.2.3 The Rules for CLCs

The rules specified in D. 95-07-054 (Appendices A and B)and D. 95-12-056 (Appendix C) can be divided into two main categories: rules governing pricing and business practices, and rules

governing consumer protection. Appendix D Section D.2 of this report contains some excerpts from the CLC rules which suggest analogies for the electric industry.

In the area of pricing and business practices, there are rules applying to: prior customer notification of rate increases; nondiscriminatory service; limited obligation to serve; required Emergency 911 service; special services for deaf and otherwise disabled persons; prompt repair response; information disclosure to the Commission; review of Commission-mandated bill inserts; handling of customer deposits; and redlining.

In the area of consumer protection, there are rules applying to: formal and informal complaints; required disclosure of company information to customers; the process for entering contracts and initiating service; information required on customer bills; establishing credit; handling of customer deposits; notifications on rates; handling of bill disputes; discontinuation of service; change of service provider; slamming; and privacy of customer information.

6.2.3 Some California Statutes Relevant for Electric Service Providers

Appendix D Section D.3 itemizes some relevant portions of existing California statutes. This material is presented for information purposes only. No analysis has been performed to decide whether these provisions may be considered adequate to govern business practices in the electric services marketplace. Specific areas covered in these statutes include: prohibition of trusts and other forms of anti-competitive behavior; distinction between acceptable cost-based pricing and unfair discriminatory pricing; misleading advertising claims; equal treatment of customers with regard to credit and deposit policies; disclosure of credit terms; confidentiality of customer credit information; disclosure by businesses of their own financial status; fraud allegations against the customer; complaint resolution; and, consumer participation in rulemaking proceedings.

6.2.4 Energy Service Providers in Other States

Appendix D Section D.4 contains some illustrations of codes of conduct for competitive retail providers and for monopoly utilities in relation to their affiliated retailers.

In the gas industry, codes or standards of conduct govern relations between local distribution companies (LDCs) and their retail marketing affiliates. FERC Order 497 contains Standards of Conduct for the wholesale gas market, which were implemented to address potential abuses in dealings between interstate gas pipelines and their merchant affiliates. The FERC Order 497 Standards have provided a model for several state standards of conduct for the unbundled retail gas market. In some cases the standards reviewed in Appendix F were the results of stakeholder working group consensus processes.

State Standards of Conduct in the natural gas industry were intended mostly to prevent anti-competitive behavior by regulated pipeline companies in favor of their competitive marketing affiliates. They address the following areas: comparable access to transport service; comparable access to non-public LDC information; non-disclosure of private customer information; physical and accounting separation of LDCs from their affiliates; tying of transport discounts to affiliate-provided services; disclosure of LDC transport discounts; equal access to LDC gas supplies or capacity; complaint resolution procedures; marketing assistance by an LDC to its affiliate; and, prohibition of joint calls and joint promotions.

6.3 Scheduling Coordinator Requirements

6.3.1 Transactions Requiring Certification

The concept of a Scheduling Coordinator (SC) was first surfaced in the final stages of WEPEX discussions preceding the April 29, 1996 filing to FERC by the three IOUs. The nature of the SC described there is incomplete. Discussions within DAWG have generally agreed that relationships between the ISO and SCs will be governed by FERC jurisdiction. However, parties have generally agreed that relations between SCs and their customers should be subject to state regulation, if this is found to be desirable.

6.3.1.1 Transactions with the ISO

SCs will need to be certified prior to submitting schedules to the ISO. The certification requirements to be a SC will be defined as part of the development of the ISO and will be documented in the February 1997 WEPEX filing to the FERC. Some parties believe that the ISO should be responsible for determining certification requirements and performing the certification. Other parties believe that while the ISO may be the administrator of the performance of the certification, both the FERC and the CPUC should determine the certification requirements in some type of joint fashion.

6.3.1.2 Transactions with Other Market Participants

Parties have not agreed whether, if at all, SC transactions with other market participants should be regulated. The following two views have been expressed.

6.3.1.2.1 ALTERNATIVE: Free Market Approach

Transactions between the SC and other entities besides the ISO will not be subject to regulation or certification requirements. These transactions are part of the operation of a free market and will be governed by the business relationships between the parties. If a SC does not offer the market suitable terms, it will have no business partners.

6.3.1.2.2 ALTERNATIVE: State Regulation of Transactions

While market discipline will provide some limitations on SCs, there is a public interest in some oversight and regulation of these crucial players in the new market structure. This regulation would include: (1) restrictions on the release of customer-specific usage data provided to the SC as required for settlement purposes, (2) requirements for a SC to cooperate with other SCs in good faith to allocate settlement costs to customers, and (3) applicability of all standard requirements for fiduciary responsibility in handling customer's imbalance settlement costs and discharging customer obligations with the ISO.

6.3.2 Basic Certification Requirements

SCs will be required to ensure that they can meet their financial obligations and have the technical capabilities to perform the functions of a SC.

Proof of Financial Integrity. SCs will have to provide the ISO security to prove they can pay all settlement charges. Possible forms of proof include: performance bond, letters of credit, deposit, and mortgage on assets.

Information Communication Capabilities. SCs will have to demonstrate that they can provide nomination information and hourly load data to the ISO: on a timely basis, with a compatible communication protocol, in the correct format, and without error. Of course, this should not be interpreted to mean that the SC will require aggregators to have hourly metered data, because some aggregators may have customer groups using load profiles.

6.4 UDC Requirements

6.4.1 Obligation to Connect and Obligation to Serve

[*NOTE: The the following paragraphs and the alternatives presented in Sections 6.4.1.1 and 6.4.1.2 represent the views of the parties who drafted them. No general DAWG consensus was achieved on these issues.*]

Restructuring is making old notions about the obligation to serve obsolete. For the vertically integrated utility, the obligation to serve once meant the requirement to connect end users and to assure them reliable, bundled electric service. Later, the obligation to connect and take power from QFs was added. Under restructuring, however, electric supply will become competitive, and the utility distribution company (UDC) will serve competing suppliers as a common carrier. Already, the Energy Policy Act and FERC rulemaking have transformed the formerly "voluntary" choice to provide transmission service to competing suppliers into an obligation to serve. As restructuring proceeds, utilities will no longer have an obligation to supply electrons to direct access customers. Utilities will retain the need to plan for the needs of their remaining bundled customers and to report those needs to the power exchange, but electric procurement for bundled utility customers will become the obligation of the power exchange.

Restructuring will also transform the obligation to provide ancillary services. Previously, utilities were responsible for furnishing all ancillary services. Under restructuring, the Power Exchange will procure ancillary services for UDC core customers, but for direct access customers ancillary services will become the ultimate responsibility of the ISO. Responsibility for operating the transmission system, managing transmission congestion, and balancing system supply and demand will also devolve to the ISO.

Thus, under restructuring, the obligation of the utility to supply electrons and ancillary services ends. The obligation to connect wholesale and retail customers, however, remains. Indeed, it expands into an obligation to offer common carrier access to T&D based on comparability to a new class of T&D customers: competing generators and retail providers who need access to T&D to reach wholesale and retail customers.

6.4.1.1 ALTERNATIVE: Obligations of UDCs to End Users and Retail Providers

The following subsections deal separately with the obligations of the UDCs to retail users, and to competing wholesale or retail service providers. The underlying principles are:

1. An obligation to provide a function exists only where there is a continuing natural monopoly.

2. No obligation to perform a function exists where there is workable competition.

3. The comparability principle regarding transmission access and pricing is extended to include retail customers distribution.

6.4.1.1.1 Obligations to Serve End Users

1. The UDC will connect end users to the distribution system at fair and reasonable rates. With the elimination of the obligation to generate or procure electric supply, the UDCs' obligation to serve end users is reduced to an obligation to connect them, subject to line extension and other rules that may apply.

2. The UDC will deliver energy from competing retail providers to end use customers at fair and reasonable rates based on the comparability principle. Comparability and open access to T&D are crucial to permitting retail providers to compete for end use customers. Unbundling of T&D costs facilitates open access.

3. The UDC will include all of the energy and ancillary service needs of bundled customers in its demand bid to the PX. This obligation to plan for the needs of bundled customers is a vestige of the former obligation to generate or procure electric supply.

4. The UDC will take back returning direct access customers as bundled customers, subject to fair and reasonable administrative fees and any notification requirements that may apply. The obligation to take back returning customers is intended to facilitate competition between the UDC and direct access providers by keeping barriers to exit and return for UDC customers low.

5. The UDC will be default provider for customers not served by competing providers. Service to low income and any other high risk customers served by the UDC will be supported by the Public Purpose Low Income surcharge fund.

6. The UDC will not be the provider of last resort of energy or any ancillary services to direct access customers. Direct access is by definition competitive, so no obligation to serve will exist for the UDC. Distribution ancillary services such as grid or voltage support and reliability will be the responsibility of the ISO. Ultimately, they should be unbundled so that wholesale and retail competitors can self-provide ancillary services.

7. The UDC will not be obligated to provide metering, billing or other competitive functions to direct access customers or customers with contracts for differences. Metering, billing and other competitive functions are competitive, so no obligation to serve will exist for the UDC. Indeed, one could argue that no obligation exists for the UDC to provide metering etc. to bundled customers. ESCOs providing energy management services are capable of providing competitive services such as metering.

8. The UDC will not be obligated to provide any competitive customer service such as energy efficiency, load management or power quality to any customer. Functions provided by competitive markets by definition are not part of a monopoly obligation to serve.

6.4.1.1.2 UDC Obligations to Serve Competing Wholesale and Retail Providers and Generators

1. The UDC will have the obligation to connect central and distributed generators to the transmission or distribution system at fair and reasonable rates. Analogous to the obligation to connect end users is the obligation to connect competing generators, subject to interconnection standards and tariffs, and other rules that may apply.

2. The UDC's transmission system will have the obligation to provide open, non-discriminatory transmission wheeling service to all generators and retail providers at fair and reasonable rates, pursuant to ISO protocol. Transmission wheeling is covered in FERC rulemaking, and is based on the comparability principle.

3. The UDC will have the obligation to provide open, nondiscriminatory distribution wheeling service to all retail competitors and distributed generators at fair and reasonable rates. This extends open wheeling access to distribution based on the comparability principle, so that those competitors can reach customers. This permits of generators connected to distribution to sell either to wholesalers or retail customers. It may result in ad hoc extension of ISO jurisdiction into distribution.

4. The UDCs will have the obligation to expand transmission and distribution facilities at fair and reasonable rates. The UDCs and their affiliates will be obligated to not substitute their own distributed generation for T&D upgrades or expansion. Under restructuring, T&D deferral by UDCs is undesirable because expansion of T&D is necessary to accommodate competing generators and providers in their efforts to reach wholesale and retail customers. Furthermore, utility-owned distributed generation would also defeat vertical unbundling. It would also entail cross-subsidization and monopoly leveraging from the T&D function into generation and retail services, which are competitive. Competing generators and providers should have the option of constructing T&D expansion, paying the UDC to provide T&D expansion, or strategically locating generating plants to avoid T&D expansion.

5. The UDCs will have the obligation to bill competing providers for their use of UDC distribution plant. This will permit competing providers to offer bundled service to customers.

6. The UDC will be obligated to make customer-specific data available to competing retail providers with the consent of the customer. This is necessary to help create a level playing field between the UDC and its potential competitors. The fee charged to competing providers for such information will be the UDC's cost of gathering and disseminating such information.

6.4.1.2 ALTERNATIVE: UDC Obligations to Customers

The UDC shall continue to fulfill its obligation to connect customers to the system on a non-discriminatory basis whether or not the customer procures energy through Direct Access, the Power Exchange or the UDC. This obligation, tantamount to ensuring open access to the retail market, is subject to the UDC's creditworthiness evaluation, according to CPUC rules, unless or at least until such time that credit risk is or can be unbundled.

The UDC will have the obligation to connect customers to the electric distribution system and to deliver energy from the transmission system and generation markets to customers.

The UDC will have the obligation to plan, construct, operate, and maintain the distribution system (the wires and associated physical assets), including responding to customer inquiries and customer outages.

The UDC will have the obligation to procure energy via the Power Exchange (PX) for UDC full-service customers and UDC real-time-pricing (virtual direct access) customers during a transition period.

In addition to energy procurement, many functions such as billing and metering, if determined by the Commission to be competitive, could be done by entities other than the UDC. The UDC will have the obligation to provide those services only to UDC full-service and real-time-pricing customers. (This does not preclude the UDC from contracting with other providers to perform such functions for their customers, however.)

The UDC will be the provider of last resort for energy, and any related services determined by the Commission to be competitive, during the transition period. However, the UDC's energy procurement obligation will be satisfied by submitting load bids to the PX. The UDC will have no energy procurement planning obligation and will not be responsible for energy shortfalls in the PX. Nor will the UDC have any planning function for other competitive services for which it is the default provider.

The UDC obligation ends at the customer's service point, except that metering equipment will continue to be a UDC responsibility for UDC full-service and real-time-pricing customers.

Alternative 6.4.1.2 PRO: Customers have a choice of suppliers for services that the Commission has found to be competitive and suitable for provision by entities other than the UDC. This approach thus increases the likelihood of competition from new entrants.

Alternative 6.4.1.2 CON:

1. The UDC should retain the right to present a bill to all of its customers. Regardless of who provides the energy to the customer, the UDC will still have to perform measurement, calculations and other billing functions for customers using its facilities.

2. Customers are exposed to the risks of energy shortages in the market and the PX, since the UDC has no long-term procurement function for energy or capacity. This is the *quid pro quo* for moving to competition.

6.4.2 Custodian of Customer Information

[*See Chapter 7 for a full treatment of this subject*.]

At the present time the incumbent utilities are custodians of the customer information they have been collecting and maintaining over the years. (The term "custodian" refers only to the fact that the utilities possess this customer data and are regulated entities having certain responsibilities regarding the its use. It does not necessarily imply anything about who owns the data, which is discussed in Section 7.5.) Under restructuring, the UDCs will still maintain the existing customer data bases and will continue to collect and maintain customer data.

The CPUC has ordered that customer-specific data held by the IOUs must be made available to competitors in the generation sector, subject to a requirement to obtain customer consent. Chapter 7 discusses the implementation of this order. The present section is intended only as a brief overview of what the custodian function entails.

The UDC as custodian of customer information has three responsibilities.

First, to release some of the contents of their customer data bases to eligible competitive energy service providers, once customer consent has been obtained. The details of such information release — the specific data to be released, the means of releasing it, the eligible recipients of the data, etc. — are still to be decided. Specific proposals on these details are described in various sections of Chapter 7.

Closely related to the general CPUC order to make customer information available to eligible competitive suppliers is the continuing responsibility to provide information directly to customers or their authorized agents upon request. The diversity of new providers and the competitive pressures of the market require that the UDCs respond to such requests in a timely manner and provide the information in a standard user-friendly format.

Second, to prevent release or disclosure of customer data where consent has not been given. Specific proposals in this area are described in Section 7.8.

Third, to prevent privileged access to customer data by specific competitive firms, in particular the UDCs' own competitive divisions or affiliates. Specific proposals in this area are described in Section 7.10.4.

In the terminology of this chapter, the first and third of these responsibilities fall under the market rules for fair competition, while the second falls under the market rules for consumer protection.

6.4.3 Billing For and Remittance of Revenues for Energy Service Providers

[*See Chapter 9 for a full treatment of this subject*.]

The UDC may remain responsible for billing, payment processing and collections pertaining to the services which are provided exclusively by the UDC, that is, monopoly distribution services which are not open to retailers. The UDC may also retain the obligation to provide billing, payment processing and collections services for those distribution services determined to be competitive (i.e., which may be provided by retailers) for which the UDC is default provider. The UDC may also be responsible for billing the Public Goods Charge (PGC), the CTC and ISO/TO charges, as well as local taxes, franchise fees and other such charges applicable to the UDC's services.

The customer is responsible for the remittance or payment of these charges to the UDC and for all commodity charges whether purchased through the UDC or a retailer. If the retailer fails to pay the UDC on behalf of the customer and there is inadequate security, the UDC will attempt to collect all monies from the customer who remains the customer of record. The UDC may enforce payment of UDC charges by exercising exclusive shut-off rights according to CPUC rules, but shall not use this means of enforcement on behalf of retailers. That is, the retailers bear the risk of unpaid balances for any services provided to customers. However, if the retailer ceases to provide energy service to a customer for non-payment, the UDC may shut off that customer to prevent the customer from "leaning" on the UDC and PX.

Some parties assert that the UDC shall only be obligated to bill customers for services it provides. Charges such as a Public Goods Surcharge and the CTC that are based on the amount of energy used should be billed by the energy service provider. The UDC may contract with the ESP to bill for those charges, but otherwise should not be required to bill the customer. Some parties have asserted that the UDC need not even be required to issue a bill.

6.4.4 Coordination of UDC Load Forecasts to Power Exchange

All parties agree that the UDC has an obligation to provide a load forecast for its generation service customers to the PX for both the 24 hour-ahead and hour-ahead energy markets. There was disagreement among DAWG participants about how this forecast should be prepared. At least two views exist.

6.4.4.1 ALTERNATIVE: UDC Loads by Differencing

As described in the WEPEX April 29, 1996 filing with FERC, the UDC will provide its system load forecast to the Power Exchange (PX). The PX will provide its total load forecast to the ISO. The ISO will determine the dispatch for generation and inform the PX of the UDC residual forecast, which it calculates by subtracting out bilateral arrangements submitted by scheduling

coordinators from the UDC system load forecast. The UDC is then responsible for supplying, from generation bid into the PX, only the energy which is not provided by bilateral arrangements through scheduling coordinators.

Alternative 6.4.4.1 PRO: This minimizes the role of the UDC is determining the amount of non-UDC energy that is required through the PX.

Alternative 6.4.4.1 CON:

1. The UDC will face some imbalance risk if the scheduling coordinators cannot accurately settle on an hourly basis. This is exacerbated in the event of load profiling for customers served by non-UDC providers who do not settle accurately with the ISO on an hourly basis. This creates settlement issues between the UDC and the non-balancing retail provider.

2. This option presumes that existing IOU short run load forecast for unit commitment and system dispatch are transferrable to the setting of a UDC and its load forecast to the PX; this is an incorrect presumption, and could lead to significant financial errors by the UDC that will increase rates for its ratepayers. Among the many differences is the necessity for UDC load forecasts which are in the form of price bids, so that the PX price determination process has an opportunity to use load reductions to determine the market clearing price. In order for the UDC to prepare a load forecast in the form of price bid is knowledge of the price responsiveness of its customers through load shedding, price capped bids, RTP or TOU tariffs, etc. The UDC cannot know this for direct access customers without grossly extending its scope into the business arrangements of direct access customers.

6.4.4.2 ALTERNATIVE: Parallel Preparation of Load Forecasts

In this alternative, the UDC and any direct access providers each prepare load forecasts for their own customers independent of each other, and submit these load forecasts through the normal processes envisioned for each market participant. In the case of the UDC, this load forecast would be its 24 hour-ahead and one hour-ahead submissions to the PX. In the case of direct access providers, these load forecasts would be coupled with generator schedules for balanced schedules to be submitted through a scheduling coordinator to the ISO.

Alternative 6.4.4.2 PRO:

1. There are several reasons why the UDC will not be sufficiently knowledgeable about individual customer loads supplied by direct access providers to be able to make accurate load forecasts, thus this option removes a difficult or impossible task from the UDC.

2. This option places the responsibility for load forecasting on the provider of energy where it belongs, and makes the forecasting process indifferent to changes in metering and data communication practices that might result from distribution function unbundling.

3. This option recognizes that load forecasting by the UDC for PX determination of a market clearing price purposes is not the same as IOU load forecasting for system dispatch purposes.

Alternative 6.4.4.2 CON: This approach is different from that submitted by WEPEX to FERC.

6.4.5 Responsibility for Safety and Reliability

The UDC retains the exclusive right and obligation to ensure the safety and security of the electric distribution system. Safety-related services are thereby deemed UDC monopoly services and may not be performed by third parties except where outsourced to qualified third parties while remaining under UDC management and control. In no case shall the customer or its agent undertake any action which has implications for the safety and security of the distribution system without the express permission of the UDC.

Minimum standards to ensure safety and reliability of the electric distribution system and customer service quality and safety should be required of all providers similar to the rules, regulations and general orders adopted by the Commission for the deregulated telephone industry.

The California Legislature mandated in 1996 that the Commission establish standards for electricity distribution. The "Supplemental Report of the 1996 Budget Act, 1996-97 Fiscal Year," compiled by the Legislative Analyst's Office, July 7, 1996, p. 48, Item 8660-001-0462, states as follows:

"1. *Standards for Electric Distribution.* On or before December 2, 1996, the commission shall prepare and adopt specific, measurable and enforceable standards for electric distribution system maintenance and operations to ensure system reliability and to minimize or prevent service interruptions due to storms, earthquakes, fires and other disasters. The standards shall specify tree trimming and brush clearing requirements, consistent with existing, laws, which ensure that the electric distribution system is protected from damage. The standards shall require the commission to investigate and take appropriate action against utilities which fail to meet the standards. The commission shall report to the chairs of the appropriate policy and fiscal committees in each house and the Chair of the Joint Legislative Budget Committee (JLBC) on the adoption of these standards on or before January 1, 1997.

"2. *Standards for Electric Distribution Under Electric Deregulation*. On or before June 30, 1997, the commission shall develop and adopt standards which will ensure the continued safety, maintenance, and reliability of the electric distribution system under orders issued by the commission to restructure and deregulate electric services. These standards shall ensure that the system for the delivery of electricity to utility customers is not compromised, reduced, or otherwise diminished due to increased competition in the marketplace for electric services. The

commission shall report to the chairs of the appropriate policy and fiscal committee in each house and the Chair of the JLBC on the adoption of these standards on or before July 1, 1997."

6.5 Competitive Electric Service Provider Requirements

[*Note. There is disagreement about whether regulators should impose registration and other requirements on electric service retailers. Among those favoring registration, the predominant view is that the CPUC should be the principal state agency responsible for registration and oversight. The Consumer Protection and Education subgroup expects to address this subject further in its October 30th report for the Commission. In the mean time, the next two subsections present different proposals that convey the flavor of the alternative approaches to the problem. Section 6.5.1 sets forth a position favoring no CPUC registration, while 6.5.2 sets forth a position describing why and how the CPUC should perform registration and oversight. In addition, the reader should see the closely related discussion of rules governing aggregation of customers, in Chapter 10.*]

6.5.1 ALTERNATIVE: Minimal Certification Requirements

Private business transactions between suppliers and their customers should not be regulated. Although certification should not be a requirement for transactions that occur in the free market, suppliers may decide it is in their best interest to obtain an independent certification rather than demonstrate their capabilities to potential customers. However, suppliers may need to prove capability before interacting with the systems of the UDC, ISO or PX. Examples of such interactions include consolidated billing by the supplier or UDC, ancillary services bids to the ISO, and demand bids or purchase requests from the PX. Data exchange with those parties may require that suppliers demonstrate that they can provide the required information on a timely basis, with a compatible communication protocol, in the correct format and without error.

Rather than demonstrate capabilities to potential customers (e.g., financial solvency, technical competence, insurance, licensing), suppliers may prefer to join a "registry of qualified providers." The registry could be maintained by a free-market registry service, by scheduling coordinators, or by the ISO. It should be left up to the market to decide if there is a need and to develop the details. If a regulated entity desires to develop a registry service, the requirements and details should be reviewed by the regulating body to ensure fairness and prevent favoritism toward affiliates. Although pre-qualification by a registry may be needed to protect smaller customers and others without negotiating strength, it should not be a requirement for entry into the market.

Alternative 6.5.1 PRO: Minimal regulatory interference.

Alternative 6.5.1 CON:

1. The proposal is not consistent with the way the CPUC and Legislature dealt with unregulated telecommunications providers. Subsequent telecommunications abuses affirm the need for regulatory oversight and enforcement powers.

2. As described above, electric service is a necessary commodity. By law, it is required for habitability, in contrast to telephone service.

3. The proposal does not address the relative unsophistication of small business and residential customers in making electric purchase transactions.

4. The proposed registry is an acceptable self-policing effort by electric providers but it should not be exclusive of regulatory oversight.

5. Minimum protection of the public interest. In particular, involves no retail regulation or oversight by an expert agency of market structure allowing retailers with market power to engage in abuses subject only to the antitrust laws which are costly and slow and in any event not preventative in the first instance. Also assumes that the entire Public Utilities code is rendered moot with respect to retail generation -- which seems not to be the legislative intent.

6. May require re-regulation of industry if this approach fails to protect public.

6.5.2 ALTERNATIVE: Regulatory Oversight of Electric Service Providers

6.5.2.1 Summary of the Proposal

The proposal described in this section is based upon two primary principles stated below, the arguments for which are presented in the subsections that follow.

First, any energy service provider interacting directly with retail customers must be registered, licensed and bonded. This entails filing of corporate information and posting a bond with the CPUC. Upon satisfactory completion of these requirements, the provider receives a license.

Second, the CPUC is the logical lead agency for enforcement. The CPUC can revoke a license if violations of market rules are proved and, when timely action is needed, the CPUC can suspend a license or curtail solicitation of new customers if the likelihood of violations is established by staff or customers.

6.5.2.2 Retail Customer Interaction Compels Licensing and Bonding

Competition will engender the entry of a number of service providers. Some will offer brokerage, some aggregation services, some demand-side services and some will offer services that have not even been envisioned at the moment. Such is an unfettered market.

The issue is whether the retail market will be entirely unfettered. The answer is no. Like almost every other service in the United States, a certain amount of regulatory oversight is necessary to ensure consumers are not defrauded and the competitive market is functioning properly.

Because electric service is a necessity and because consumers are relatively unsophisticated in valuing and understanding electric services, the electric industry will require greater regulatory oversight than other standard retail services. Customer sophistication may develop over time, while the necessity aspect of electric service will become increasingly important as the telecommunications and computer industries mature.

Regulators must focus upon retail transactions between electric providers and retail customers, with an emphasis on small business and residential customers. As with long distance and local phone service providers in California, any provider offering electricity brokerage, marketing, aggregation or equivalent services directly to retail customers should be required to register, post a bond with and be licensed by the CPUC. That way, if any service provider interacts with a retail customer, that provider will fall under the jurisdiction of the CPUC.

Some parties believe, however, that while the smaller customers will need the safeguards of regulatory oversight by the CPUC of electric providers (registration, bonding, licensing and dispute resolution), the oversight required of electric providers, marketers, brokers, etc. in business dealings with larger customers should be much lighter. That is, those firms whose sole business activity is with large customers might only require some minimum registration with the CPUC. This is founded upon the notion that larger customers would have the resources to make their business decisions from a far more well-informed position than the smaller customers. As a proposition, this large customer size could initially be set at 100 kW per meter, or alternatively, a customer with smaller load but business revenues exceeding $5 million per year.

The purpose of licensing and bonding is to proactively ensure accountability by energy service providers and to ensure that customers have adequate recourse in the event that the provider fails to perform.

6.5.2.3 Providers Not Subject to Registration

Not all retail energy service providers will require registration. The purpose of registration is to ensure accountability and recourse where electric service is provided to retail customers. In some circumstances, accountability is inherent in some energy providers.

For example, municipal or other public entities providing service within their own franchise areas would not fall under CPUC jurisdiction and thus would not be subject to licensing. However, if any such entity were to offer services to non-franchise customers, the same accountability would not exist and then licensing and bonding would be warranted. Non-franchise customers cannot vote, they cannot easily appear at public hearings and they do not reap many of the tax-related benefits available to municipalities.

Energy service companies offering only demand-side management, on-site generation or other services unrelated to purchase of electric service would not need to be licensed so long as those

providers are not participating in or benefitting from publicly-funded energy programs, such as DSM or renewable credits. If, however, they participate in a publicly-funded program or if they bundle other energy services with energy brokerage service, then licensing is warranted.

Finally, energy cooperatives should not be required to be registered so long as all cooperative members are owners of the cooperative, and thus enjoy the higher level of accountability and recourse enjoyed by owners.

Other providers, such as brokers interacting with aggregators, generators, companies offering ancillary services and scheduling coordinators are not required to provide a filing or bond with the CPUC so long as their interaction remains with other wholesalers. However, these providers may have to fulfill registration requirements established by the ISO.

Proposal 6.5.2.3 PRO: Municipalities that provide electric services in areas outside of their franchise must be treated the same as other private service providers. Customers who live outside of the franchise area of a municipality have none of the privileges or protections of customers who live in a franchise area and can vote new representatives to the municipal board. Moreover, there is no valid legal or policy basis to exempt municipalities doing business outside their franchise area from CPUC oversight. Any argument for exemption, as presented below, would also logically apply to any municipal utility from another state doing business in California. The Tennessee Valley Authority, for example, could begin selling energy services to California customers and claim exemption from CPUC oversight.

The purpose of CPUC oversight is to ensure that customers who have complaints against energy service providers have low-cost, adequate redress. A customer without a franchised voting right has no greater protection than any other customer. That is why CPUC oversight is necessary.

Proposal 6.5.2.3 CON: The purpose for registration and bonding is to protect the interests of retail consumers from fraud or failure of undercapitalized providers. Municipal utilities should not be required to post bonds in order to provide services to non-franchise customers as they do not pose the same level of risk that non-utility aggregators do. In fact, municipal utilities, like the IOUs, pose very little financial risk to retail customers. The rationale presented for registering municipal utilities who do business with non-franchise customers in this section does not take into account that municipal utilities are subject to rigorous oversight by their respective city councils and community member-comprised utility commissions, are required to conduct their businesses in an open public forum and therefore, do not pose anywhere the same level of risk that unregulated market participants pose. The oversight responsibilities of the city councils and community member-comprised utility commissions provide customers of municipal utilities with considerable opportunities for redress not available to customers of other energy service providers.

In the current monopoly electric utility structure, the reins of power are primarily in the hands of the utilities but in the competitive electric utility industry structure of the future, where

customers will be able to choose their supplier of energy services, the reins of power will be held by the customers. In this type of business environment, both non-franchised customers and franchised customers of municipal utilities will be highly valued by the municipal utilities and non-franchised customers will receive services on equal terms as franchised customers. The likelihood that municipal utilities would not provide equivalent services and opportunities for meaningful redress to both franchised and non-franchise customers alike is insignificant, if not zero, considering that the non-franchise customers have a choice to walk and take their valued business elsewhere, as happens everyday in the deregulated telephone and transportation industries, if the municipal utilities discriminates against them.

6.5.2.4 The Nature Of and Rationales For Registration with the CPUC

In order to serve retail customers, non-exempt energy providers should be required to provide to the CPUC and keep updated, their legal name(s), business address, state where incorporated or associated, date of incorporation, articles of incorporation or association, name and title of each officer and director, name, title and phone number of a designated customer service contact person, name, title and phone number of the regulatory contact person, brief description of the nature of business being conducted and disclosure of any civil or criminal action taken against the company or any officer or director for any illegal acts related to the operation of any business for previous ten years. This information gives regulators and consumers the necessary information they need to judge the viability of the provider.

The rationales for this registration requirement are:

a. Retail customers must be able to learn about the owners, the location and financial viability of any prospective provider. In order to ensure uniformity, that information should be on file with a clearinghouse. The CPUC fills that role.

b. In order to guard against undercapitalized, fly-by-night or unethical companies, the CPUC must have a means of screening prospective energy providers. Retail customers, especially residential and small business consumers, will not have the wherewithal to screen prospective providers. The dissemination of misinformation and other abuses experienced in the solar hot water market and the long-distance telephone market have graphically demonstrated the need for the ability to screen providers.

c. Registration preserves the CPUC's jurisdiction over these entities

6.5.2.5 The Bonding Requirement

In addition to informational registration, a prospective provider must also provide either a bond or some alternative insurance that would give customers a fund against which to secure damages attributable to fraud or non-performance. The reasons for bonding are:

a. The upfront costs of entering the electric services market is fairly low. Retailers need only a computer and customer leads. A bonding requirement will therefore not put an undue burden on any prospective new entrant, as its start-up costs are relatively low.

b. Without a bond, it is likely that complainants and their attorneys or representatives will not be able to recover damages caused by failed service providers.

c. The bonding process itself serves as a useful screen against companies or individuals with questionable financial pasts who seek to enter the electricity market. Bonding services will either decline to bond or will require higher deposits from entrants with questionable records.

The amount of the bond would be established based upon the prospective number of customers to be served. For example, a local community provider planning to serve 50 residents could post a very modest bond, whereas a large provider planning to serve customers throughout the state would require a more substantial bond. Energy providers who also offer financial contracts for managing risk may need to be bonded as well, perhaps at an even higher level than the others.

The CPUC would be required to ensure that bonding costs do not become so prohibitive that they discourage new entrants. At the same time, bonds or other insurance mechanisms must be adequately secure to protect against anticipated claims by customers. The insurance companies that serve Californians are obligated to provide such assurances in order to offer service in the state. Itt is anticipated that the costs for energy service bonding should not exceed costs faced by insurers.

6.5.2.6 Why Electric Registration Must Be More Stringent Than Telephone

As discussed above, the registration process needs to be stringent enough to protect customers but not so onerous as to create a barrier to entry. For local telecommunications companies the CPUC has developed a non-dominant carrier registration process that is not overly burdensome. It requires filing with the CPUC the identities of the owners and officers of the corporation, a description of services to be provided and basic financial information to ensure the economic viability of the company.

Telecommunications registration does not require bonding, however. This is precaution that is necessary for electric service for many reasons.

a. Electric service is generally is more expensive than phone service. Thus greater potential losses are likely and greater protection is warranted.

b. Electric service is a necessary commodity. State statute bans habititation of a residence that does not have electric service.

c. Small consumers will be very vulnerable to commercial exploitation during the transitional period of deregulation. Telephone service deregulation has been phased over a decade, whereas electric deregulation will occur more rapidly.

d. Long distance and OAS deregulation have led to significant consumer abuses and are among the most common consumer complaints in the 1990s.

e. Experience in other locations where direct access has been tried suggests that consumers may be attracted to fixed-price offerings. Such offerings represent an implicit financial hedge or a derivative security, and thus carry a significant degree of market risk. For instance, an energy retailer might offer fixed prices for a calendar year beginning in January, and while winter prices are lower than the annual average the retailer would accumulate several months of overpayment by the beginning of summer. If that retailer then fails to perform during the summer, the amount of overpayment is a loss to the customer.

Proposal 6.5.2.6 CON: While electric service is a necessary commodity, there is not agreement that electric service is more expensive than phone service. If one examines the portion of the electric industry that is being opened up to competition at this time, i.e., the energy costs, one finds that the cost is not greater than the phone bill. This comparison is perhaps misleading.

6.5.2.7 Revocation and Suspension of Licenses Are CPUC Responsibilities

The CPUC's ability to revoke, suspend or limit a license is absolutely necessary for adequate enforcement. In the initial 5 to 10 transitional years of electric competition, new entrants must be clearly noticed that questionable business practices, undue risks and shabby treatment of customers will not be tolerated. The potential for abuse and the serious ramifications of that abuse mandate adequate enforcement powers by the agency. The CPUC's staffing and its expertise on energy matters positions it as the only logical state agency that can be charged with enforcement.

Consumers might also be able to look to civil courts for contractual, tortious or statutory remedies (e.g., under Business & Professions Code Section 17200 et seq). However, these cases would be expensive to pursue and the civil courts are not equipped to handle the load of individual complaints that could occur with the advent of competition. Moreover, the courts will not be well-positioned to establish uniform industry rules where patterns of rule violations or shabby customer service are established. Thus, the CPUC should continue its role as lead enforcement agency for customer complaints about all retail energy services.

This enforcement power should be anchored by CPUC licensing of energy service companies. Without licensing, enforcement of CPUC rules would be ineffectual. The CPUC market rules would include a code of conduct and a set of specific minimum standards of service. Further

discussion of such a code of conduct is contained in the next section, and an example with specific rules is given in Appendix D at the end of this report.

The CPUC should have the ability to suspend, limit or revoke a service provider's license depending on the gravity of provider malfeasance. Revocation would be invoked only where due process had been afforded to a provider. However, injunctive suspension or limitation of a license could be imposed upon a showing that CPUC rules had likely been violated by a service provider and that significant damage could be caused by a continuation of service by that provider.

Proposal 6.5.2.7 PRO: Will provide better consumer protection to have an expert agency with regulatory authority over all players.

Proposal 6.5.2.7 CON: 1. Could overwhelm CPUC. 2. Does not address market structure issues.

6.5.2.8 Proposed Code of Conduct for Retail Energy Service Providers

The CPUC must require all registered energy service companies to adopt a minimum code of conduct. In the nascent energy services market, companies and customers will be unclear on their corresponding responsibilities and expectations. In order to facilitate smoother transition to a robust competitive market, the CPUC should specify a minimum code of conduct that would be adopted by all energy service companies registering with the CPUC. This code would provide guidance for companies and their employees for all retail transactions. It would be distributed to all employees of these energy service companies and provided to customers upon request. As a minimum code, it would represent the "floor" of what would be expected, but could be surpassed by companies.

Such a code could be used as a standard upon which company actions would be judged. It is neither likely nor desireable for regulators and lawmakers to devise rules and regulations for all possible forms of consumer problems. Thus, regulators would use the minimum code of conduct as a basis for determining the appropriateness of company conduct where a specific rule and regulation does not fit the conduct. Regulators may use the code as a basis for sanctioning a company.

A minimum code of conduct would address the following areas: provision of understandable and accurate information to customers; notification of change of service or intent to disconnect; explanation of denial of service; handling of deposits; handling of complaints; confidentiality of customer-specific information and customers' right of access to their own information; non-discrimination in availability and terms of service. See Appendix D.6 for an example of specific wording of such a code.

Proposal 6.5.2.8 CON:

1. Some parties assert that such a code may add confusion rather than order to the retail market due to vagueness and unclear legal status of rules. For example, item 2 in the model code presented in Appendix D.6 requires "adequately reliable, safe, and affordable service." What do these terms mean? Such rules give no meaningful guidance. In addition, many of these conduct issues are already covered by existing provisions of law. Item 13, for example, is already covered by civil rights laws and general consumer protection stautes. The Commission would therefore have to carefully specify the relationship of any new rules to existing laws and regulations.

2. The market and existing laws pertaining to consumer protection and access to customer information can be relied upon to determine appropriate conduct. The explosion of customer options, product combinations and technological developments will occur too rapidly to be conducive to pre-established rules. The market will sort out appropriate behavior and practices. Default service will be available for those not wishing to participate in the competitive market.

6.5.2.9 ALTERNATIVE: Regulation of market structure by CPUC

Modelled on FERC's parallel regulation of the competitive wholesale electric market, this approach assumes that the CPUC still has an obligation under the PU Code to regulate retail energy markets to protect the public interest and ensure that electricity rates are reasonable. All retailers (aggregators, brokers, generators, marketers, etc.) would be "electric corporations" and "public utilities" per Section 216-218 of the PU Code. Each retailer would have to either comply with the PU Code's ratemaking requirements or demonstrate to the CPUC that it lacked market power. For most retailers who are also wholesalers, presumably this requirement could be met by simply showing evidence of FERC approval of wholesale market based sales, unless the retail market presents special circumstances.

PRO:1. Protects against market power abuses.

2. Provides comprehensive parallel economic regulation of wholesale and retail energy markets.

3. Can be done by CPUC under existing law.

4. Avoids risks of deregulation followed by reregulation if market proves to have structural problems.

CON: Could be "overkill" and add unessesary burdens to the new generation market (but has not slowed entrance of new players at wholesale level).

6.5.3 Permissible Retail Territories for Unregulated Utility Affiliates

Parties have offered two alternatives regarding the geographic areas open to the retail activities of competitive affiliates of monopolies. The first alternative says that such affiliates should be allowed to compete within their parent utilities' service areas. The second allows them to operate outside of their parent utilities' service areas.

6.5.3.1 ALTERNATIVE: Inside the Parent Utility's Service Area

An unregulated affiliate of an incumbent utility should be allowed to compete for customers within its parent utility's existing service area.

Alternative 6.5.3.1 PRO:

1. An additional competitive provider of electric service means more competition.

2. Affiliates may be able to offer a wider range of services than the UDC. Some customers may want affiliate service as a matter of informed choice.

3. Inclusion of affiliates maintains the competitive status quo relative to out-of-state utility affiliates and other providers. For example, serving a regional or national chain account would not be possible for the UDC affiliate if it is excluded from serving in its affiliated utility service area.

4. The CPUC already has effective rules governing the conduct of utilities and their affiliates. In addition, the CPUC has enacted rules for behavior of utilities and affiliates in a holding company structure.

5. Some parties assert that favoritism by the UDC is virtually precluded by comparable open access transmission and distribution service and CPUC regulation of customer information access.

6. Allegations (below) that affiliate transaction guidelines have been ineffective are completely unsubstantiated and wrong. Annual audits of financial transactions have never uncovered a significant abuse. Furthermore, the provisions in the restructuring decision addressing affiliate issues are fully adequate to address potential concerns.

Alternative 6.5.3.1 CON: Allowing an unregulated utility affiliate to compete for customers in the utility's service area would substantially jeopardize the Commission's goal of an effectively competitive market for electricity. A critical condition for a competitive market is that all providers are on a level playing field. This condition is unlikely to be fulfilled when unregulated

affiliates are cross-subsidized by the utility. While there is always the potential for cross-subsidization between regulated and unregulated enterprises, the likelihood of such actions is significantly increased when the utility and its unregulated affiliates are providers in the same market. Under such a scenario, it is easier for cross-subsidization to occur and more difficult to detect.

The opportunity to cross-subsidize is also facilitated by a holding company structure. All three IOUs either are already under or have applied for a holding company structure. The holding company has a fiduciary responsibility to its shareholders to provide the highest possible returns for a given risk level. The holding company that controls the utility has available to it market information which it can pass to its unregulated affiliates.

The Commission recognized the serious potential for self-dealing despite existing affiliate transaction rules and consequently prohibited any contracts between the distribution utility and its affiliated generating companies. [See D. 95-1-063, p. 71.] Consistent with its policy of preventing affiliate abuses and its goal of nurturing an electricity market in its infancy to a fully competitive market, unregulated affiliates of the utility should not be permitted to compete in the utility's service area during the transition period.

A competitive market will be most successful if monopoly power is mitigated. Allowing an unregulated affiliate to compete in the parent utility's service territory does not provide the proper assurances against monopoly power.

6.5.3.2 ALTERNATIVE: Outside the Parent Utility's Service Area

Unregulated affiliates of the incumbent utility should be allowed to compete for customers outside of the utility's existing service area.

Alternative 6.5.3.2 PRO: Unregulated affiliates should be allowed to compete to serve customers outside of their utility's service area. There is little potential for market abuses since it is unlikely that the unregulated affiliate would have access to the proprietary information of an outside utility. Thus the unregulated affiliate would provide customers with more choices and enhance competition.

Alternative 6.5.3.2 CON:

1. California utilities' market power and brand recognition are so significant as to warrent prohibition of affiliate transactions within California until such time as the competitive market is well established. Moreover, it is politically untenable for the IOUs to be recovering 100 percent of their stranded costs while at the same time increasing stranded costs by pursuing direct access transactions.

2. Market power concerns remain, even when unregulated affiliates compete outside of a utility's service area. The CPUC must be vigilant in monitoring for informal reciprocal arrangements whereby an IOU-owned disco will be more preferential to another IOU's affiliate in recognition that IOU's disco may return the favor to its own unregulated affiliate doing business in the disco's service territory. For example, utility A's disco will likely give preferential treatment to utility B's unregulated affiliate doing business in A's franchise territory because of the ability of B's disco to create problems for A's affiliate doing business in B's franchise territory. In the event that such arrangements, informal or not, are detected, the CPUC must be empowered to revoke the right of an IOU affiliate to do business in California.

6.5.4 Reciprocity for Utilities and Affiliates Conducting Business Under Jurisdictions Other than the CPUC

Utilities that are not under the jurisdiction of the CPUC may have marketing affiliates desiring to conduct retail business in the CPUC jurisdictional area. Can and should restrictions be placed on the retail activities of such affiliates if their parent utilities do not face retail competition in their own service territories? Only one alternative was offered and discussed on this subject, but no assessment was made of the group's support for this alternative.

ALTERNATIVE: The CPUC Should Require Reciprocity.

To the extent that these entities do not allow similar access in their own utility service territories, they should be denied certificates to conduct retail transactions within the CPUC jurisdictional area. This would not preclude these entities from doing business in the wholesale market or with the Power Exchange.

The CPUC may implement this restriction by exercising its right to condition certificates to participate in the retail market. In the event that the CPUC may not exclude such entities from the retail market, it should condition the certificates to require that the affiliate provider disclose the fact that its affiliated utility does not provide the same opportunity for its own customers.

Alternative 6.5.4 PRO:

This policy will facilitate the expansion of customer choice, because neighboring IOUs with marketing affiliates will more likely consider allowing their captive utility customers to have choice among competitive retailers if that is a requirement to participate in the California retail market. The issue is not that plants outside of California which have rate-based treatment and recovery from their own customers may sell at production cost into California. That would be a pure good for California consumers. The issue is the access to retail customers and the unfair opportunities for out-of-state utilities to engage in wrongful self-dealing and cross-subsidies at the expense of California utilities and other competitors. While individual customers would benefit in California, the opportunities for an expanded competitive electricity market in other

states would be left to the whims of regulators and legislators in those states and the imagination of utilities in an effort to stifle competition in their back yards. It is the utilities that must make the commitment to a competitive market to facilitate real change in an expeditious manner.

Alternative 6.5.4 CON:

There is an argument that the CPUC does not have legal authority to impose restrictions upon the retail certificates of providers if they are located out of California. This is based upon federal jurisdiction over interstate commerce.

There is also the position that a necessary condition for a successful Direct Access program is for competitive supplies to be available to end-users on a retail basis. Restrictions on a supplier based upon the need for reciprocity between the California IOUs and a supplier's territory would be a barrier to successful deregulation. Not only would these restrictions potentially prevent out-of-state utilities from supplying power at retail in the Direct Access market, it would give an unfair marketing advantage to retail providers with no service territories of their own. Out-of-state utilities have no control over their public utility commissions or legislatures so that they do not have the ability to influence the pace for retail customer choice. Further, even if these utilities suggested implementing such reciprocal access, there would be a significant delay before it could be implemented. The immediate impacts would be felt without an opportunity for the out-of-state utility to remedy the situation.

6.6 Requirements for Franchise Fees and Utility User Surcharges

[*Note: Sections 6.6.1 and 6.6.2 represent alternative views of this subject*.]

6.6.1 ALTERNATIVE 1

This section outlines issues and proposed requirements for the Franchise Fee and Utility User Tax Collection in a restructured electric industry. These issues arise from the financial obligations of local governments and the recognition of the need for a level playing field for all electricity market providers with respect to these financial responsibilities.

Without the adoption of clear franchise fee collection requirements, the roadmap decision adopted in December 1995 by the Commission could have negative impacts on the financial stability of local governments. The restructuring of the electricity industry has entered the phase where the next round of significant decisions will be made. Decisions made at this point must assure the ability of local governments to collect all revenues under the powers of their franchise fee authority.

6.6.1.1 Statutory Authority

The statutory authority of local governments to collect franchise fees or the utility user tax does not appear to be in question. Moreover, in 1993 SB 278 (Beverly) was enacted with Provisions to protect status quo rights to franchise fee collection under deregulation.

The potential financial impacts of electricity restructuring on municipal revenues is significant as a result of the multiplicity of participants and the unbundling of costs. Full collection will be difficult. The interests of local governments should be recognized in rule-making at various levels to protect the municipal financial position. In the future, the utility bill is expected to show generation costs, transmission and distribution costs, transition costs and social program costs. The capability to identify payments due from each of the components of the unbundled base utility expenditure in a restructured electricity industry and the mechanics of collection are the subject of concern.

The CPUC's rule-making must protect the rights of municipalities to full revenue collection under the authority of the franchise fees. The mechanics of how these fees would be collected requires CPUC guidelines. The public record of transactions under direct access and bilateral agreements should be the basis for franchise fee review, or, if these transactions are not public, consumers should be required to document their actual costs, on a confidential basis, or to pay the required fee based on an otherwise applicable tariff rate.

6.6.1.2 Fees

All energy consumers or their service providers must be required to remit pertinent franchise fees and utility user tax. The transparency and disclosure of all relevant financial transactions must be sufficient to support the requirements of fee collection. The multiplicity of participants who should be required to remit payment for use of rights-of-way for electricity transportation need to be examined. Examples of energy market place participants and their respective financial transactions that should be subject to the fees are listed below.

1. Local Distribution Company. Fixed and variable costs for transportation, metering reliability of system, and competitive transition charges.

2. Investor-Owned Utility. Fixed and variable costs and transition costs collected by IOU generator for use of generating electricity and for the non-bypassable charges for the recovery of stranded assets. The generation costs are payable to the Power Exchange or the direct access provider.

3. Energy Consumer or Service Provider. Costs for services including metering, billing and wholesale procurement provided by ESP; part of the transaction between end users and generation companies or the power exchange. Costs for services including metering, billing and wholesale procurement provided by aggregator; part of the transaction between end users and IPP's.

4. Independent Power Producer. Fixed and variable costs collected by the generator for sale of electricity. The generation costs are payable to the Power Exchange or the direct access provider, and are a portion of the revenue which is collected through bilateral agreements, or virtual direct access. No fees would be collected directly from generators, but would be collected indirectly.

5. Power Exchange. Cost for managing purchases of electricity from IOU generator and IPP generators; costs are passed on to IOU and IPP.

6. Energy Research and Development Organization. Cost to continue R&D activities, currently included as part of the utility bill.

7. Public Service Provider. Surcharge or cost to provide service to low-income and hardship case electricity users, currently included as part of the utility bill.

6.6.1.3 Summary

Disclosure and mechanics for the collection of the franchise fees and utility user taxes in exchange for the right to share in the use of municipal rights-of-way, or systems in lieu of these rights-of-way must be achieved. Procedures to ensure complete and transparent collection should consider requirements for open access to information, records of usage, open access to fees and charges associated with usage, payments to service-providers which are rendered based on historical data, and records remitted from virtual direct access providers. Some parties point out, however, that

such procedures may violate a right to privacy or require disclosure of competitively sensitive information.

6.6.2 ALTERNATIVE 2

Franchise fees are paid by electric utilities, pursuant to contracts with municipalities and State law, as compensation for the use of the public streets. The State has already recognized this need and adopted SB 278 (Sections 6350 et al. of the Public Utilities Code), which created the Municipal Lands Use Surcharge. (Added Stats 1993, ch. 233, effective July 30, 1993). Section 1 of that act reads:

> In enacting this chapter, the Legislature finds and declares that changes in the public utility regulatory environment have inadvertently provided for the potential erosion of the franchise fee base upon which local government has become quite dependent for its financial stability. Further, the Legislature has determined that there exists the possibility that these same regulatory changes may not ensure equitable treatment between customers purchasing gas or electricity from a utility and customers purchasing gas or electricity from other sources. Therefore, the purpose of this act is to provide protection for the financial integrity of local government and to ensure that all customers purchasing gas or electricity who transport gas or electricity on transmission systems that are subject to a franchise agreement share equitably in the burden of compensating local government for the private use of public lands.

The duty to collect the surcharge is imposed on the energy transporter who has a franchise agreement with the local government entity, and the surcharge amount is based on the "weighted average cost of the energy transporter's ... electricity." Energy transporters who are not public utilities are to use "the equivalent tariffed rate of the commission regulated energy transporter operating in the same service area." Public Utilities Code Sections 6353 and 6354.

Energy transporters were required to begin collecting the surcharge April 1, 1994. (The municipalities were authorized to collect the surcharge during the interim period between August 1, 1993 and March 31, 1994, in recognition of the termination of the gas utilities targeted sales programs as of July 31, 1993.) As of that time electric energy transporters did not have "transportation customers," but they will have the duty to collect the municipal lands use surcharge as soon as the electric industry restructuring is in place and they have transportation (only) customers. Accordingly, the separation of the commodity (electricity) and its transportation will not affect the franchise fees the municipalities receive.

6.7 Issues for Master-Metered Customers

[*Editors' note: The format of this section departs somewhat from the norm of this report. Specifically, we provide with attribution the issue statements and proposals of two parties: the Western Mobilehome Park Owners Association (WMA), representing the owners and operators of private electric distribution systems serving mobilehome parks, and the Golden State Mobilehome Owners League (GSMOL), representing the residents of mobilehome parks.*

[From the beginning of the DAWG process, a representative of WMA has attended meetings and presented the WMA position. For some reason, however, the GSMOL representative found out about this process only days before the August 19th edition went to print, and called the Editing Team to request that GSMOL's viewpoint be included in the DAWG Report. Following our policy of trying to ensure adequate representation of opposing views and our understanding that this policy is consistent with the Commission's wishes, the Editing Team included GSMOL's material even though it had not been subjected to questioning and discussion at meetings.

[Sections 6.7.1 and 6.7.2 present, respectively, the WMA and GSMOL submissions. Section 6.7.3 presents alternatives proposed by other DAWG parties.]

This section deals with privately-owned distribution systems that are not Commission-certified public utilities (i.e., systems that do not hold Certificates of Public Convenience and Necessity). These systems are typically served by local utilities through master meters. Initial discussions in the DAWG indicated interest in considering such systems in mobilehome parks, apartment complexes, shopping centers, industrial parks, and military bases. As of the date of this Report, however, parties' written submittals for this section pertain primarily to mobilehome parks, with peripheral reference to apartment complexes.

6.7.1 Western Mobilehome Parkowners Association (WMA)

6.7.1.1 Statement of Issues

Several questions arise in relation to Direct Access through privately-owned distribution systems that are not Commission-certified public utilities, including the following.

1. What are the rights and responsibilities of the distribution system owners?
2. To what extent, if any, does the Commission have authority over the operation of these systems?
3. Do the rights, responsibilities, and authorities depend upon the geographic location of the distribution system, or upon the status of the utility that delivers electricity to the master meter (i.e., regulated vs. municipal)?
4. To what extent should Direct Access be made available to end-users served by these distribution systems?

5. Should there be a distinction between systems that resell distributed electricity through individual customer meters vs. those that distribute without metering?

6.7.1.2 Background on Mobilehome Park Electricity Distribution

There are two modes of electricity distribution system ownership and operation in California mobilehome parks. During park construction owners can choose to either:

1. allow the local utility to extend its distribution system to each space within the park (consistent with line extension rules applied to the park owner), thereby making each future park resident a direct customer of the utility; or
2. install, own, operate, and maintain the distribution system themselves.

Historically, most owners have chosen the second option. These park-owned distribution systems are typically installed underground, and consist of transformers, line and service wires, meters at each mobilehome space, and other ancillary hardware. Each system is connected to a local utility at one metered point (the "master meter") through which the park owner purchases electricity for resale to park residents.

The Western Mobilehome Parkowners Association (WMA), a statewide non-profit voluntary membership organization representing park owners, estimates that today there are approximately 3,500 park-owned distribution systems (in some cases a single park contains more than one system) purchasing electricity from PG&E, SCE, and SDG&E for resale to roughly 300,000 residents. WMA also estimates that there are nearly 1,000 additional mobilehome parks served directly by PG&E, SCE, and SDG&E, where each resident is an individual utility customer (option a above). The owners of these latter parks are not involved in supplying electricity to residents.

Pursuant to Section 739.5 of the Public Utilities Code, funding for the historic "average" cost of owning and operating park-owned distribution systems is provided through a "discount" to park owners on electricity purchases at the master meter. In addition, Commission Decision 95-02-090 ruled that this discount is the park owners' exclusive means of recovering the costs of park-owned distribution systems. Thus cost recovery mechanisms like utility surcharges, rent adjustments and special lease provisions are prohibited.

For historical perspective, the cost recovery restrictions imposed by Section 739.5 in 1976, and Decision 95-02-090 in 1995, were adopted after the vast majority of park-owned distribution systems were installed. The practical result is that, after making good-faith investments in electric distribution systems, many park owners have been subsequently prohibited from fully recovering their original investments (i.e. those whose costs are higher than the historic average cost). In addition, virtually all park-owned systems will be unable to recover the full cost of any new system replacements or upgrades purchased with today's or tomorrow's (i.e., not historic average) dollars.

These restrictions also mean that park-owned distribution systems are not permitted the same degree of cost recovery as PG&E, SCE, and SDG&E. Whereas the utilities are able to apply for rate increases, on a dollar-for-dollar basis, to recoup all reasonable expenditures, park owners only receive reimbursements based upon historic average costs, regardless of their actual costs. There is thus a considerable dis-incentive to spending new monies on the operation of park-owned distribution systems.

6.7.1.3 ALTERNATIVE: WMA's Proposal on Mobilehome Park Direct Access

WMA presumes that the residents of parks served directly by PG&E, SCE, and SDG&E will automatically receive Direct Access on the same basis as each utilities' other residential customers. This is not necessarily true, however, for residents served through park-owned distribution systems.

After considering various possibilities, and practical constraints, WMA recommends that Direct Access should be available to park-owned distribution systems at their master meters, but would not recommend that it be available individually to each park resident unless a number of concerns are resolved.

6.7.1.3.1 Unresolved Concerns

In WMA's opinion, the cost and administrative complexity of allowing each resident to choose an energy supplier will also probably be more expensive to the resident than is the current system. Unanswered questions regarding such individual resident Direct Access are: who will read the meters; who will repair meters and system failures; who will be responsible for meter and system routine maintenance, etc.? In this vein, the following are additional examples of the kinds of costs and complexities that concern WMA.

1. Access to Private Property. Park-owned distribution systems are located entirely upon private property and are not subject to public utility easements. In addition, most streets inside of mobilehome parks, where residents live, are private. Special access, equipment placement, and indemnity arrangements (i.e., for marketing calls, meter installations, incidental damages, etc.) may thus be required for each potential energy supplier in each park. These arrangements must be consistent with the property rights of each owner, as well as the owners' privacy obligations to the residents.

2. Bill Questions and Complaints. With multiple energy suppliers, park residents will expect owners and managers to respond to many new electricity bill-related questions and complaints that are more properly directed to the suppliers. There may also be a need for park owners to mediate disputes between residents and suppliers in the interest of park tranquillity.

3. Non-Payment/Shut-Offs/Collections. Collection problems are expected to become extremely complex and difficult to resolve. The constraints of landlord-tenant laws may not be consistent,

for example, with procedures enabling collections from customers who fail to pay their energy suppliers or the UDC.

4. Billing and Customers Services. Park owners now bill residents based upon the local utility's residential rates. This can already be a complex task given that different residents within the same park can have different baseline allowances (i.e., all-electric and medical) as well as CARE eligibility. Adding the possibility of multiple energy suppliers, each with its own rate structures, could make billing extraordinarily complicated and costly.

5. Cost Allocation/Recovery. Multiple energy suppliers raises the possibility that the park owners' costs to provide distribution services may both increase, and vary significantly from resident to resident. There is, however, no apparent process available to properly allocate costs among residents, resolve disputes, and assure full recovery of added costs by the park owner. This high degree of financial risk and uncertainty is unacceptable to park owners.

In light of these concerns, and in order to assure as many Direct Access benefits as possible, WMA proposes adoption of the following set of "Principles" governing Direct Access in mobilehome parks containing park-owned distribution systems.

6.7.1.3.2 Mobilehome Park Direct Access Principles

1. Mobilehome park owners who own the distribution systems inside of their parks, and who do not themselves engage in Direct Access in relation to their parks (i.e., the park owner has no connection to the electricity supplier), should individually be assured recovery of any additional distribution-related costs resulting from Direct Access and electric industry restructuring, including any stranded distribution costs, to the same degree that such cost recovery is assured to each UDC.

2. If the decision is made that Direct Access should be made available to residents of parks served through park-owned distribution systems, it should be conditional upon being conducted on a pass-through basis (i.e., the park owner has no connection to the electricity supplier), provided that, notwithstanding the provisions of Decision 95-02-090, each resident choosing pass-through Direct Access pays for any added costs including, but not limited to, added costs incurred by the park owner for metering, data collection, billing, and administration.

3. Direct Access should be available to park-owned distribution systems (i.e. park owners), provided that residents who choose not to participate in Direct Access do not pay rates in excess of the rates that they would pay if they were served directly by the local UDC with electricity from the Power Exchange, consistent with the requirements of Section 739.5 of the Public Utilities Code and Decision 95-02-090.

4. Notwithstanding the provisions of Decision 95-02-090, mobilehome park owners who own the distribution systems inside of their parks, and engage in Direct Access in relation to their

parks (i.e., for example as aggregators, energy suppliers, or brokers), should be permitted to independently set prices and terms for their additional Direct Access-related energy and distribution services, and should be required to recoup their costs to provide such additional services exclusively from the revenues received for those services.

5. The first group of UDC customers to receive the option to choose Direct Access should include a proportionate share of park-owned distribution systems.

Alternative 6.7.1.3 PRO

1. Provides equitable energy supply choices for both park residents and park owners.

2. Based upon practical experience in owning and operating small distribution systems, resolving WMA's concerns will minimize future difficulties for residents and owners.

3. Park owner support assures the broadest opportunity for Direct Access by park residents

4. Assures that added costs are paid by those responsible for them, i.e. the Direct Access customers, and not by non-participants.

5. Least costly way to offer Direct Access in parks.

Alternative 6.7.1.3 CON

See the list of WMA unresolved concerns given above.

6.7.2 Golden State Mobilehome Owners League (GSMOL)

This is the only direct-access proposal submitted on behalf of mobilehome park *residents.* The proposal seeks to place park residents on an equal footing with other residential customers by having utility distribution companies (UDCs) take over mobilehome park systems.

6.7.2.1 Background to Proposal

Most of the larger and more "modern" California mobilehome parks were built in the middle to late 1960s and featured submetered gas and electric distribution systems. Now approaching 30 years of use, many of these systems are in need of rehabilitation or replacement. Mobilehome park owners, termed "master-meter customers" in the Public Utilities Code, received net income under tariff for the operation of those systems. Variously called rebates, refunds, discounts or rate differentials, the long-standing practice of supplying master-meter customers with tariff-based income was codified in 1976 in Public Utilities Code section 739.5.

Though the purpose of this tariffing practice was to provide park owners with money to own, operate, maintain and replace their submetered systems, there was never any accounting or segregation requirements attached to these funds. Accordingly, most if not all park owners operate their systems with little or no reserves. Moreover, it should be emphasized that park owners have had the option of direct service in their parks and those who chose submetered energy distribution did so with the clear understanding that the rate differentials were always averaged and never set to meet *individual* system requirements. Evidence of these averaged rate differentials is found as far back as the mid-1950s and there is *nowhere* any indication that parks received, or were entitled to receive, individually-calculated rebates from either the serving utility or the CPUC.

The establishment of submeter rate differentials or discounts was to provide park owners with income independent of space rents for submeter service, while charging park residents only that amount which they would have to pay if they were directly served by the utility. This practice would avoid rate discrimination, which would result if, for example, residents in certain parks were required to pay more for their submetered service than residents in directly-served parks or in parks with more efficient submetered systems.

In most submetered mobilehome parks, the electricity delivered to each space is below the 100 amps provided in directly-served facilities. Though rated at 50 amps, many park systems provide considerably less and restrict residents from operating air conditioning units. Nonetheless, park residents pay the same 1996 utility rates as if they were directly served by utility systems at 100 amps.

Since 1976 the CPUC has instituted *three* investigations into mobilehome park submeter utility service. The second investigation case, entitled *Lifeline Quantities of Gas & Electricity, etc.*, 6 CPUC Rpts. 2d 767, D. 93586 (1981), was primarily concerned with the present issue of compulsory utility takeover of mobilehome park systems. That case had substantial participation from CPUC staff, the utilities, various park owners, the Western Mobilehome Association and GSMOL. In the *Lifeline Quantities* decision, the park owners received the "... continuation of the present practice of granting a mobilehome park developer the option of either installing his own gas and electric distribution in mobilehome parks or having the utilities serve directly...." Slip opinion at 16. However, the Commission acknowledged that the minimum construction standards for mobilehome parks and public gas and electric utilities were not the same and that "the utilities generally exceed these minimum standards." Id., slip opinion at 33. Moreover, in that investigation case, CPUC staff testified that mobilehome park gas and electric installations were not fully reliable and that "... the utilities install more reliable and safer systems." Id., slip opinion at 10.

> As discussed in detail, each utility has its own construction standards based on various regulatory requirements ... This variance in utility facilities is even more exaggerated in the case of MHPs where the various systems were constructed in accordance with standards that are markedly different from those used by the utilities. *For the utilities to take over such systems, even those in good, safe*

operating condition, it would be necessary to substantially increase their material inventories, procure additional equipment, and provide additional training for their personnel, together with possible changes in the manning of their crews. The alternative to such actions would be the complete rebuilding of the systems thus acquired. In either case, the cost would be prohibitive and would impose a severe financial burden on the ratepayers should the utility for one reason or another be unable to assess such costs against the MHP operator. Under these circumstances the utilities' position on this matter does not appear unreasonable, and we will leave the matter of the possible takeover of such systems for resolution by the utilities and MHP operators on a case-by-case basis as problems arise.
Lifeline Quantities, supra, slip opinion at 50 (emphasis supplied).

6.7.2.2 ALTERNATIVE: A two-step program for mobilehome resident direct access: (1) utility takeover and upgrade of submeter systems; (2) direct access election by mobilehome residents.

The GSMOL proposal is based on the *current* version of AB 622 (Conroy). The bill requires the utility, if requested to do so by an owner of a mobilehome park within the area in which the utility has the obligation under existing law to provide service, to develop, pursuant to specified procedures, a proposal for the transfer of ownership from the park owner to the utility. At this juncture, the bill has no focused opposition, the utilities and GSMOL having taken a "neutral" position on the currently amended version (7/11/96). It appears that the measure will be enacted into law and will provide several new sections in the Public Utilities Code.

In order to be eligible for a transfer, a master-metered system in a mobilehome park must meet four criteria: (1) The system must be capable of providing end users a safe and reliable source of gas or electric service. (2) The system must be in compliance with the CPUC's general orders concerning design and construction of such systems. (3) The system must be capable of serving the "customary expected load" in the park. (4) The system must be "compatible" with the utility's systems, compatibility requiring that the presence of non-standard parts in the system would not cause a substantial increase in the frequency or duration of outages or that they have some remaining useful life.

The transfer process works as follows: (1) The park owner requests the utility to conduct a transfer review. (2) Within 90 days, the utility must make a preliminary survey and develop a cost estimate of what is necessary to bring the system into compliance with the above-noted four criteria. (3) Upon payment by the park owner, the utility must conduct the engineering evaluation. (4) On the basis of these documents the utility must present a proposal for the transfer of the system and, at this juncture, the residents of the park must be notified. There are alternative criteria and procedures for effecting the transfer which are found within the bill. After reviewing the proposal, the park owner may agree to the transfer, decline to proceed or present objections to the utility and request mediation through the CPUC. If the park owner, at some

point in time, accepts the transfer proposal then the public utility is obligated to proceed and, ultimately, the submeter system will become the property of and be operated by the serving utility.

If the goal is to provide direct access for all electric energy consumers, and without discrimination against those who live in mobilehome parks or apartment complexes, then the first step is to physically rehabilitate the internal submeter systems through the type of scheme envisioned by AB 622 (and supported by WMA). Once the utilities are directly serving each mobilehome space within a given park, the residents of that park will be free to buy and negotiate between competitive energy retailers and the like.

Alternative 6.7.2.2 PRO

1. Will upgrade systems to current standards in each mobilehome park where a takeover has occurred and provide direct utility service.

2. Will leave submetered mobilehome parks under existing regulation and protections.

3. Will allow individual mobilehome park residents to freedom to choose between competitive sources of electrical energy.

4. Will ultimately shift burdens of rehabilitation to general ratepayer class and avoid discriminatory rent increases in mobilehome parks.

Alternative 6.7.2.2 CON

1. Will not resolve issue of how the "normal" utility rate is to be applied in mobilehome parks which are not subject to takeovers.

2. Will allow takeover procedures controlled by mobilehome parks unless and until AB 622 is changed.

3. Will require funding, probably from general ratepayer class, to allow takeovers and line extensions in mobilehome parks.

6.7.3 Two Additional Alternatives

6.7.3.1 ALTERNATIVE: Unrestricted Consumer Choice Combined With Revised Mobilehome Park Ratemaking Treatment

This alternative permits mobile home park residents to freely elect to participate in direct access provided the customer is willing to pay all incremental costs incurred by the mobile home park

operator in connection with this participation. To permit this freedom requires some fundamental changes in the statutory and regulatory treatment of mobile home parks. Thus, opportunities for mobile home park residents to participate in direct access can be made unrestricted, provided many of the current restrictions on recovery of mobile home park operator costs are also removed. The WMA alternative resolves these same concerns in a more piecemeal fashion, directed solely to the narrow issues of direct access. This alternative permits the same freedoms, but suggests allowing them in the context of a much more complete change in the ratemaking process for mobile home park operators and the customers they serve.

PUC 739.5(a) restricts mobile home park operators to charge their tenants no more for their electricity services than would be charged by the local utility of the customer, were the customer to be receiving service directly from the local utility. In addition, the local utility is required to offer a cost-based discount to the mobile park reflecting the costs of the utility avoided by serving a single master-meter customer rather than a substantial number of small customers directly. These restrictions ignore the possibility that legitimate costs for the mobile home park may exceed those of the local utility on a per customer basis. While these restrictions have already imposed non-recovery of costs in some instances for mobile home park operators, the incidence of this would be larger under direct access. The mobile home park operator would be expected to address a series of complexities concerning metering, billing, and other costs of serving customers who elect direct access for their energy needs, and would receive only the local utility cost per customer of these expenditures. The ability of the local utility to amortize such expenditures over a vastly larger customer base compared to the mobile home park operator's much smaller customer base implies an unfair reference for judging mobile home park cost recovery.

The solution to both the existing problems with lack of comparable costs recovery and unfair restrictions on recovery of costs of direct access is to completely revise the regulatory oversight for mobile home parks. The following points form the basis for a new regulatory paradigm:

1. Using the local utility's costs as a basis for judging mobile home park costs should be eliminated.
2. PUC 739.5 should be repealed and mobile home parks should be provided direct rate oversight as if they were a utility distribution company.
3. Mobile home park distribution company (MHPDC) should be required to identify costs of service for full service and direct access customers, and rates should be established on the normal basis of recovery of all costs deemed to be prudent.
4. The MHPDC should be considered a resale customer of the UDC, paying appropriate costs for the distribution services received from the UDC, without reference to the other costs of the UDC which the MHPDC does not receive.
5. Reflecting the much smaller size of mobile home parks, the CPUC ought to provide this review and authorization of rates on an expedited basis, much as small local water distribution companies are given more abbreviated oversight compared to large ones.

As a result of this revised regulatory treatment, a MHPDC should establish an appropriate tariff for services it provides to a direct access customer, the CPUC should authorize these rates, and the potential direct customer should be allowed to elect direct access provided he/she was willing to pay the appropriate costs.

Alternative 6.7.3.1 PRO

1. MHPDC customers can be provided consumer choice just like any other resident of a UDC because incremental costs of service will be recovered directly from them, implying no cost subsidies from other park customers nor unfair disallowance of MHPDC costs.

2. Existing problems created by D.95-02-090's unfair restrictions on mobile home park operator cost recovery will also be resolved.

3. MHPDC customers may obtain lower cost generation energy compared to being a "master-meter customer" of the UDC, if the MHPDC is able to negotiate a "bilateral" contract with a generator or power supplier.

4. Quality of electricity distribution services provided by a mobile home park to its tenants may increase.

Alternative 6.7.3.1 CON

1. A California statute will have to be revised, the CPUC will have to develop abbreviated rate oversight for MHPDCs, and the CPUC will have to expend some resources authorizing MHPDC tariffs.

2. Some mobile home park tenants will pay more for distribution function services than they would have paid to a UDC.

3. It is highly unlikely that such a wholesale revision of law and policy can be accomplished and implemented by 1/1/98.

4. Forces mobilehome park and apartment complex owners to become UDCs at significant expense and effort.

6.7.3.2 ALTERNATIVE: Direct Access Election at the Master Meter and Not Beyond

Under the CPUC's 12/20 order, IOUs are required to provide direct access to customers who meet certain eligibility requirements. Owners of apartment or mobilehome park master meters are single utility customers or accounts under present law and CPUC regulation (see PU Code 739.5). The individual tenants of mobilehome parks and apartment buildings under master

metering are not such customers. Allowing individual tenants to elect direct access would be the same as allowing the master meter to rely on the UDC for a portion of its generation requirements while entering into bilateral contracts with other parties for the remaining portion -- a position rejected by almost all DAWG participants. That is not to say these end-users cannot benefit from direct access; they must persuade their landlord to elect direct access for all tenants if in their interest. If the landlord refuses, thereby denying tenants a significant benefit, presumably the park or complex will be at a competitive disadvantage in attracting tenants.

Alternative 6.7.3.2 PRO: 1. Consistent with current treatment of master meter customers and with present law and CPUC precedents.

2. Administratively simple: avoids complex metering, safety, billing, and responsibility issues Still permits end-users to petition landlords to gain direct access.

Alternative 6.7.3.2 CON: Denies the benefits of direct access to end-users whose landlords refuse to opt for direct access.

Chapter 7. Access to Customer Information

7.1 CPUC Direction

7.1.1 CPUC Decision D. 95-12-063 (Decision)

The Commission's Decision 95-12-063 recognizes that a "utility has access to considerable information about its customers" which creates "a major marketing advantage that could allow it to target and sign up preferred customers before its competitors can." [Decision pp. 71, 108.] To neutralize that advantage, the Commission ordered that "Customer-specific information necessary for the distribution functions of the utility shall be made available to all competitors in the generation sector, on terms that are fair to all competitors." [Decision, Ordering Paragraph 20, p. 224.]

The second sentence of Ordering Paragraph 20 addresses the need to prevent potential misuse of customer information. It states: "All generation providers, including the monopoly utility, shall obtain a customer's consent before accessing any proprietary information about the customer." Language in the body of the Decision refers to "customer confidentiality concerns" as driving a requirement to obtain customer consent. [Decision, p. 108.] Some customer-specific information may have been obtained by utilities only upon their acceptance of specific conditions governing how that information may be used. Other information may have been given to utilities in confidence. Before using or releasing either type of information for purposes other than specified by the those who originally provided it, utilities and other generation providers must first obtain customer consent.

Given the foregoing concerns, the central issue of this chapter is how to balance the needs and rights of customers to protect their privacy against the needs of the marketplace for information. In other words, how to define the boundary between private control of information and the public domain. The Decision recognizes that to go too far in either direction could undermine the goal of restructuring. Adequate flow of market information to all competitors is necessary for efficient market operation, but inappropriate use or release of customer information could have a harmful effect on customers. In reading this chapter, the reader should bear in mind the central problem of finding the proper balance.

7.1.2 Joint Assigned Commissioners' Ruling of May 17, 1996 (Ruling)

Item seven in the Ruling's section on consumer choice issues expanded the list of customer information access issues which Commissioners Neeper and Knight wished to address. First, the assigned commissioners directed the working group to consider "what customer information can

be provided." This requires assigning types of customer information into categories for which potentially different rules of access may apply.

Second, confidentiality concerns referred to in the Decision were further clarified in the Ruling. In addition to proprietary issues, the assigned commissioners directed the working group to consider "customer privacy." Whereas proprietary information has a foundation based on ownership, customer privacy is much broader and more complex. Privacy is not so much a function of ownership as it is control over information. Control is usually determined to be important if information about individuals could potentially be misused in a way that causes harm to the individual, which in turn is not outweighed by societal benefits. At issue is which specific customer information is protected by the right to privacy, and what kind of consent mechanism is appropriate to ensure adequate protection of privacy.

Finally, neither the Decision nor the Ruling addresses access to other utility-held proprietary information. Both refer only to information on utility customers. Therefore, information that does not describe customers is excluded from consideration at this time.

7.2 Overview of Issues and Viewpoints

7.2.1 Useful Terminology and Concepts

We may think of a system of information flows in terms of the following parties: (1) sources or subjects of the data, i.e., electric service customers; (2) collectors — meters and meter readers, as well as surveys, energy audits, service sign-up and payment procedures; (3) custodian of records, or just custodian — the entity that maintains the data and makes it available for authorized uses; (4) users or audience — parties that use customer data for various private, public or commercial purposes, which may include creating and disseminating value-added information products and services as well as providing energy services. For the purposes of this report, the users will be mainly electric service providers.

Figure 7.1 illustrates the flows of customer energy-usage data under the present integrated IOU, the bundled UDC, and a fully unbundled distribution company model. The supply of electricity requires certain information on customers and their energy usage for the purposes of rendering an accurate bill for services, collecting for services and operating the system. In addition, IOU sales and marketing departments use customer data to support public policy programs and customer retention efforts. These purposes and some others — regulatory oversight and system planning, for example — are the *primary uses* for which customer data is collected.

IOUs and bundled UDCs collect customer data through metering, customer research surveys and energy audits. Thus the IOUs and the UDCs are simultaneously collectors, custodians and users of information. As restructuring progresses and UDC functions are further unbundled, a wider

variety of entities — unbundled discos, metering firms and billing firms, for example — are likely to be collectors and custodians of customer data.

We use the term *customer record* to refer to the entire set of data associated with a given utility account number (see Section 7.2.4 for a list of specific variables and categories of data). The entity that collects the data and retains it becomes a custodian of the data or *custodian of records* (with no implications to be drawn about ownership of the data; that issue is discussed in Section 7.2.3). At present the IOUs are the principal custodians of customer records and are therefore the focus of the CPUC order on information access. In the mature competitive marketplace, the custodial function may be performed by another party or parties (see Section 7.4 for some ideas about the restructured future).

Customer data collected for various primary uses may be valuable to competing energy service providers, including commercial divisions or affiliates of franchise utilities, for developing new services and for marketing those services. As noted above, the IOUs already use customer data to support customer retention efforts where there is a possibility of bypass. In the more fully competitive environment, however, such commercial activities would be considered *secondary uses* of the data, i.e., uses beyond those for which the data was originally collected. In essence, then, the problem we must address is *how to govern the secondary uses of customer data that is collected for legitimate primary uses*. A major component of this problem is to specify the rules governing the custodian(s) of such data.

7.2.2 Principal Viewpoints Regarding Access to Customer Information

Although we have characterized the central problem as the needs of the market versus protection of customer privacy, there are actually four principal viewpoints or interests that parties have expressed about customer information, all of which we must recognize and address in a proposal to implement D. 95-12-063. The four viewpoints are: the privacy rights of customers, the information needs of the competitive marketplace, the rights of information custodians to be compensated for costs imposed upon them in making information accessible to other parties, and any legitimate proprietary rights accruing to the UDCs or other parties to customer information.

7.2.2.1 Customer Privacy Rights

The concept of customer privacy needs to be framed a bit differently for residential customers than for business customers. As private individuals, residential customers have certain privacy rights which are protected by federal and state laws and regulations, and which aim to prevent harm to individuals resulting from unauthorized release or use of certain types of personal information. For example, in the opening of long-distance telephone to competition, residential customers have experienced some intrusive or unethical marketing practices, which need to be prevented in the present context. The Commission needs to carefully weigh resulting benefits to society against costs to customers from releasing customer names, addresses, phone numbers,

energy usage histories or any of the other variables contained in the records the utilities routinely maintain on their customers.

The laws and regulations that embody the individual right to privacy do not, however, apply universally to business entities. Business names, addresses and telephone numbers are generally thought of as public information. Energy may be a significant component of a firm's production costs, however, so uncontrolled release of its usage data may provide a competitive advantage to the firm's competitors. Such data may therefore be subject to protection as a trade secret, which is a form of protection against disclosure although not formally a privacy right. As later sections will discuss, the somewhat different concerns of these two broad classes of customers will imply some different policy considerations.

7.2.2.2 The Needs of the Competitive Marketplace

The second main interest is the competitive marketplace, which consists initially of suppliers of generation services under direct access as ordered in D. 95-12-063. A fundamental assumption of restructuring is that customers will benefit from competition, an assumption that is based on the economic theory of competitive markets and requires that market participants have ready access to information about the market. Specifically, for markets to function efficiently customers need information about the products and services available, and providers need information about the demands of potential customers. An obvious problem, however, is that a release of customer information intended to reduce the barriers to entry and enhance competition may result in undesirable marketing practices or competitive harm to businesses. The rights of customers to information privacy must not be compromised in the efffort to stimulate competitive markets.

7.2.2.3 The Rights of Custodians to be Compensated for Costs

The third main interest is the class of custodians of information, most notably the IOUs at present. The information proposed to be made available to competing providers has been collected and maintained by the utilities, and the process of making it available would impose some costs on them. At the very least, there will be some costs associated with obtaining customer consent to release information and with preparing the data and delivering it to eligible providers. The implementation of information access must assess the nature and magnitude of all relevant costs, and provide means to recover those costs and compensate the appropriate parties.

7.2.2.4 Proprietary Rights to Customer Information

At least one party argues that customer information is the property of the IOU. According to this argument, investors have taken a risk by investing in the facilities to provide service under a regulatory authority. The customer information that is collected by the IOU is a consequence of the utilization of the utility’s physical assets in the provision of service, and is therefore the property of the IOU. In general, information such as a customer list of a private business is

protected as a proprietary trade secret, which means that the business cannot be required to disclose the information unless an overriding public benefit necessitates disclosure.

Other parties argue that customer information is owned by the customers themselves, and that if any monetary return is realized from the economic value of the information that return should be shared with customers. The subject of proprietary rights is discussed further in Section 7.2.4.

7.2.3 Summary Statement of the Problem

By way of summary, implementing access to customer information as ordered in D. 95-12-063 entails two main tasks:

1. Establishing rules and mechanisms to ensure fair or comparable access by competing retailers, which requires answering these questions:
    a. What kinds of customer information should be made available?
    b. Which parties should be eligible for access to customer information?
    c. By what mechanism should it be made equally available to all qualified parties?
    d. How can we prevent privileged access by some competitors?
    e. How much will information access cost, on which entities will costs be imposed, and how should costs be recovered?

2. Protecting customer privacy, which requires answering these questions:
    a. How should informed customer consent to release information be obtained?
    b. What rules should govern appropriate use of customer information by retailers?
    c. How can rules be enforced and complaints be quickly and fairly resolved?

These tasks and the associated questions will be addressed in the remainder of this chapter.

7.3 Policy Issues for the Near Term (1/1/98) and the Mature Market

Our tasks are complicated by the need to address two distinct time frames. First is the near term, which requires that we devise information access policies to support the opening of competition on 1/1/98. Second is the long term, which requires that we address information flows in the mature retail marketplace. The near term problem is in one sense the simpler one, for it focuses on the customer data bases held by the existing utilities. Our near-term objective, quite simply, is to implement Ordering Paragraph 20 of D. 95-12-063. In contrast, the mature

marketplace may feature a variety of entities that collect, maintain custody of, disseminate and utilize customer data. The long-term thus requires that we try to envision an information management regime that may be much more decentralized than the present one, yet must still support the integrity of the electricity system and the energy policy objectives of California.

Most of the discussion to follow is equally applicable to the near term and the mature market. Where material applies specifically to one or the other we try to make that clear. In particular, we provide summaries of options and recommendations in separate sections for the near term (Section 7.12) and for the mature market (Section 7.13).

7.4 Types of Information

Customer information may be classified in a number of ways. First, various types of customer information variables have different commercial value to qualified retailers. Customer information will be useful to competitive retailers for three purposes: (1) research and product development; (2) marketing and sales activities; and (3) customer service and operational functions. Second, consumers will regard some pieces of information as inherently more confidential or sensitive than others. The relative sensitivity of different data items may also vary by type of customer (e.g., business vs. residential) and by the manner in which the information is to be used. Also, whereas some information collected by utilities is available for a price from other sources, much of the higher-valued information for electric service providers is available only from the utility. This section provides a simple scheme for classifying customer information that will be helpful in addressing the issues of privacy and usefulness to competitive providers.

7.4.1 Basic Customer Information Variables

Utilities now possess — and competitive providers may in the future possess — data bases of information on individual residential and business customers. The information has been acquired from meters, market research instruments, energy audits and other data bases. Customer records in utility data bases include the following types of information variables:

1. Customer ID: name, service address, billing address, phone number, utility account number -- basic information required for obtaining electric service. Also known as *directory information*.

2. Demographic: personal, census and related data for both residences and businesses -- from market research and other data bases.

3. Usage: customer's historical metered information as recorded (monthly, TOU, load profile or real-time), plus prices and bill amounts -- part of customer's service history.

4. Credit: record of customer's promptness of payments, unpaid bills, etc. -- part of customer's service history.

5. Programs: participation in DSM programs, low income assistance, specific tariffs, etc. -- part of customer's service history.

6. Energy Audit: end uses, specific appliances or equipment, etc. -- from market research and customer participation in programs.

7.4.2 Categorizing Information for Privacy Considerations and for Usefulness to Competitive Electric Service Providers

For the purposes of this chapter, we use two criteria to categorize types of information that may be candidates for release to competitive providers. The two criteria are: Personal/Non-Personal (P/NP), i.e., whether the customer is identified or not; and Individual/Aggregate (I/A), whether the data contains individual customer records or just aggregate or statistical values. In this report the terms Personal and Non-Personal are used synonymously with Customer-Specific and Non-Customer-Specific, respectively.

These two criteria give rise to four categories of customer information as follows.

Personal-Individual (P-I)

P-I data contain Customer ID (item 1 above) connected to all, some or none of the other variables listed above. A release of P-I data may be quite limited, such as a *complete customer list* which has only item 1 for all customers, or a *categorized customer list* which has item 1 for a subset of customers grouped according to specific variables, perhaps usage > 10,000 kWh/yr, good credit, rate class, and county. Or it may be more inclusive and contain customer IDs with associated usage records, DSM program participation and credit history, for example.

P-I information tends to include the most sensitive information from a customer-privacy viewpoint, because it enables the provider to contact the customer directly and allows him to know a great deal about each customer before making contact. The potential for intrusive marketing, unauthorized uses or other undesirable outcomes is therefore very great, and customers will rightfully expect to have a great deal of control over the release of such information.

Personal-Aggregate (P-A)

P-A would contain, for example, a categorized customer listing with an associated average or typical usage history or load profile for the category, plus statistics on any of the other variables, but without any indentified individual data from items 2-6.

P-A information would likely be quite useful to potential competitive providers, for it would contain contact information for certain well-defined categories of customers. As the customer category is more narrowly defined, the information becomes both more valuable to competitive providers and possibly more sensitive from the customer-privacy viewpoint.

Non-Personal-Individual (NP-I)

NP-I would contain individual records of items 2-6 without Customer ID or the customers being otherwise identifiable. Because of the absence of customer contact information, this type of data release is not useful for targeting specific customers and does not raise privacy concerns. It can still be quite useful to providers, however, for market research and business planning.

Non-Personal-Aggregate (NP-A)

NP-A would contain only statistical data. It may represent a narrowly-defined group of customers, but none of the customers would be identified or identifiable, and none of the item 1 data would be provided in any form. This type of data is probably the most readily available from a variety of sources and of less value to competitors than the other categories of data. Like NP-I information, NP-A information does not raise privacy concerns.

As the foregoing suggests, personal information (P-I and P-A) may be further distinguished by whether or not it is *sensitive.* Sensitive personal information is "information that if disclosed or used inappropriately, creates the potential for harm to an individual." (See *Privacy and the NII: Safeguarding Telecommunications-Related Personal Information*, National Telecommunications and Information Administration (NTIA) under the U.S. Department of Commerce, October 1995, p. 6.)

At a minimum, sensitive information includes social security numbers, passkeys, and information related to health care, political and religious affiliation, sexual matters and orientation, credit and personal finances. (Adapted from *Privacy and the National Information Infrastructure: Principles for Providing and Using Personal Information*, Privacy Working Group, Information Policy Committee, Information Infrastructure Task Force, U.S. Department of Commerce, p. 3.) Also in this category would be unlisted telephone numbers, which have been provided to utilities to perform billing and service functions but nothing further.

In contrast, non-sensitive personal information is information which if disclosed would create little potential for harm to the individual either under specific provisions of use or when the probability of misuse is very low and reasonably controlled.

7.4.3 Candidates for Release to Competitive Providers

The Commission should consider establishing information access protocols, including procedures for obtaining customer consent and mechanisms for implementing access, for the following four types of customer information. Items 1 through 3 represent increasing usefulness to competitive providers as well as increasing sensitivity regarding customer privacy. All three may require some type of customer consent (see Section 7.8). Item 4 avoids the problem of obtaining customer consent, but may not do enough to level the playing field for the competitors to the incumbent utilities.

1. Customer lists. Lists of customer names, addresses and utility account numbers, and perhaps telephone numbers, with no additional information. To make this information more useful to providers, customer lists may be categorized or grouped by specified characteristics, for example, usage above10,000 kWh/year and good credit history. Release of telephone numbers should be considered carefully, however, for it may be impossible for utilities to tell whether a customer's telephone number is unlisted.

2. Enhanced customer lists. Customer lists with some electricity consumption data, perhaps the previous year's metered usage. Privacy concerns may, of course, be greater for this type of data release than for the previous type. Alternatively, privacy concerns may be lessened somewhat if the release of this information enables qualified retailers to conduct limited marketing efforts aimed at those customers most likely to benefit from the retailers' offerings, rather than more diffuse telemarketing campaigns aimed at the general public.

3. Complete customer energy records. Customer lists with all associated information except for non-energy-related information such as credit history and other personal data. While this type of information release presents the greatest privacy concerns, it would be of maximum value to competitive providers and many customers might wish to have their energy records released to suitably qualified providers. A crucial element would be to specify procedures for obtaining informed customer consent for such a release, if such consent is determined to be necessary. Some parties argue that, except for unlisted telephone numbers, none of this information is sensitive and therefore could be released without customer consent.

4. Non-personal energy data. This could include complete individual customer records with all customer identification removed, and would be useful for market research and business planning. With customer identification absent, customer privacy would not be an issue.

7.5 Proprietary Issues

7.5.1 Proprietary Nature of Utility-Collected Customer Information

Two opposing positions on ownership of customer information have been advanced in the working group. Some parties assert that customer data is the property of the utilities that have collected and maintained it. Since the utilities collect this data as a matter of necessity and incur business expenses in so doing, they own the data. Others disagree with this viewpoint, arguing that the business expense is borne by ratepayers with little or no risk borne by shareholders in the process, and that the necessity of data collection confers upon the utilities a custodial or fiduciary responsibility, but not ownership. In a similar vein, the same parties tend to assert that customers themselves own the information that the utilities have compiled — and that UDCs and retailers will compile in the future — regarding them and their energy usage.

A third position in this argument is that ownership — i.e., legal title — is too narrow to be useful without defining specific ownership rights and responsibilities. Ownership would not imply an unlimited right to use or disseminate the data in any way the owner sees fit. For example, if we were to agree that utilities own the customer information they hold at present, would this mean that they have unrestricted rights to:

1. give the information to their competitive affiliate, to benefit their shareholders?
2. sell the information for profit, without customer permission?
3. refuse to release the information to the customers themselves?
4. transfer ownership to another, possibly unregulated, entity?

At least one party to the working group process would answer "yes, subject to existing statutory restraint," to all of the above questions, arguing that the activities 1 through 4 represent the free exercise of the rights and privileges of ownership of property, which is fundamental and cannot be lightly abridged or disregarded. Utility ownership of the information is, of course, essential to this argument.

Decision D. 95-12-063 seems to have already come out against exclusive utility rights concerning customer information, at least for the near term problem of facilitating competition in generation by 1/1/98. At the very least, the CPUC decision says that possession of the information does not imply unrestricted use by the utilities. Rather, it requires them to implement fair access to all generation competitors, subject to protection of customer privacy. Looking toward the mature marketplace, the way in which the Decision is implemented will establish important precedents concerning the rights and responsibilities associated with possession of customer information, regardless of whether and how the narrow ownership question is resolved.

7.5.2. Proprietary information positions

7.5.2.1 ALTERNATIVE: Personal information compiled by the utility is owned by the customer.

As used here, customer "ownership" means the following: (1) control over the dissemination of individual customer information; and (2) the right to the monetary value from provision of personal and impersonal customer information to others. Customer ownership rights would be exercised via a standardized set of authorizations, with individual negotiation of contracts being the exception. Because customer information is integral to the operation of the monopoly distribution company functions, the monopoly would have an unlimited right to use that information in the conduct of its business operations.

Alternative 7.5.2.1 PRO

All utility collection of information from customers has occurred in a special historical context. The electric utility is a monopoly provider of an essential service. The only way for customers

to obtain this essential service has been to provide information to the utility, or to allow the utility to collect information (through meters). As noted in the historical overview, the legal oversight of release of customer-specific information is extensive. Because of these social conditions, customers who have provided information should be understood to have conditioned use of that information. Conditional use should be understood to apply even in the absence of explicit individual restrictions. The distribution monopoly's right to use maintains the conditions under which customers provided information — as a monopoly provider of essential services.

The issue of customer ownership is partially, but not completely, severable from the issue of customer control. Strong means of customer control are essential to maintain privacy. Ownership further strengthens the protection of privacy, and the California Constitution's right to privacy. Customer ownership also honors the Decision's commitment to "...the broadest possible array of choice in which the former 'ratepayer' can function as an intelligent, self-interested 'customer' (D,96-10-009 at pp.5-6)." The broadest possible array of choice must include the customer's disposition of information about the customer.

Additionally, joining ownership and control reflects common understanding. Furthermore, current practices regarding customer control over information have clearly not prevented the widespread development of extensive demographic and lifestyle characteristics of individuals. Ownership of the monetary proceeds for information provided to others is a means of replacing corporate dissemination. It will also provide a first hand explicit indicator to many individuals of the vast volume of personal information that is exchanged between businesses without customer knowledge.

Customer ownership goes beyond generally prevailing business practices. Expanded privacy protection of the electric services industry is consistent with, and expands upon the Commission's precedent treatment of caller ID service election. Setting a higher standard for the electric services industry is appropriate unless current privacy protection is determined to be fully adequate. Given apparent widespread concern and unease over privacy, it is extremely unlikely that the adequacy of privacy protection would be empirically validated.

The consequences of this higher standard are twofold. First, customers are likely to demand that competitive providers of electric services match the regulated monopoly's practices for customer ownership of information. Secondly, this step to instituting a "rising tide" in privacy protection could result in similar changes in other industries.

<u>Alternative 7.5.2.1 CON</u>

1. Customer information is the property of the investor-owned utility. It is not a public good. Investors have taken the risk and made the investment in the facilities to provide service under a regulatory authority. The provision of that service may be regulated under state authority to ensure market fairness. But the customer information that is developed by the investor owned

utility is a consequence of the utilization of the utility's physical assets in the provision of service. It is thus the property of the investor owned utility.

Utility customers do not share ownership rights of investor owned utility property. Customers are renters of the system, paying in rates the cost of using the system for the services they receive. Investors, as shareholders, are owners of the system, holding the ownership rights of property, with exclusive rights to the value of such property. Information which develops through the use of property becomes property itself and innures to the owner of property, the shareholders.

2. If the Commission were to conclude that customers own the information compiled by utilities and maintained in utility databases, unanticipated problems could result. For example, if a customer was deemed to own the customer information, that might imply that law enforcement agencies would be required to serve search warrants seeking access to customer information on the customers, rather than on the utilities, a situation which might frustrate the legitimate goals of law enforcement. Similarly, deeming customer ownership of customer information could thwart many of the legitimate uses of aggregated or non-personal information that might otherwise support restructuring efforts.

3. Ownership should not be confused with regulatory oversight over the use of an asset dedicated to public utility service. It is not necessary for the Commission to reach any resolution of the ownership issue in order to impose reasonable public interest requirements on the use of customer information by the utilities. Thus, the concerns raised by proponents of customer ownership, as stated above, are immaterial to the issue of ownership. The Commission does not need to resolve the issue of ownership as part of its resolution of direct access issues.

7.5.2.2 ALTERNATIVE: Customer-specific information compiled by the utility is owned by the utility.

Alternative 7.5.2.2 PRO

1. Customer information is the property of the investor-owned utility. It is not a public good. Investors have taken the risk and made the investment in the facilities to provide service under a regulatory authority. The provision of that service may be regulated under state authority to ensure market fairness. But the customer information that is developed by the investor owned utility is a consequence of the utilization of the utility's physical assets in the provision of service. It is thus the property of the investor owned utility.

2. Utility shareholders own databases of customer information in the same manner that they own distribution systems, or any other asset associated with a regulated monopoly service. These databases were created by the utilities, at shareholder risk. That is, in general rate cases, the Commission authorizes utilities to recover a certain amount of revenue to carry out their

obligations as providers of monopoly services. To the extent that recorded costs are higher or lower that that which was authorized, the difference is a shareholder responsibility. Thus, the cost of acquiring customer information is ultimately a business cost, which is the responsibility of utility shareholders.

3. Clearly, where the public interest requires, the Commission may impose reasonable restrictions on the use of customer database information; if usage results in revenues, the Commission may regulate the profits arising from such revenues. Thus, utility ownership of customer information is completely consistent with the Commission being able to achieve its legitimate public interest objectives regarding usage of customer information assets.

Alternative 7.5.2.2 CON

The PRO argument suggests that recorded costs in excess of authorized costs represent private business ventures, that is, risky uses of shareholder funds to develop assets whose economic value should accrue to shareholders. In some instances that may be true. In the case of customer information, however, there are some exceptional points to be noted.

Collection of certain types of customer information — such as the customer ID data needed to establish service, and metering and billing data — is covered under authorized costs for monopoly services. It is only the excess costs, which could result just as easily from inefficient operations as from entrepreneurial activity, that may have to be borne by shareholders. Ultimately the cost of acquiring and maintaining customer data is paid by ratepayers.

In some cases, value-enhancing innovations to customer data bases were results of government intervention and were resisted by the utilities when they were introduced. For example, the CEC introduced the requirement to attach SIC codes to the records of utility business customers, to facilitate load forecasting, research, etc. In the competitive environment, SIC codes on business customer records clearly adds economic value to customer data, but should shareholders enjoy gains from expending funds, whether ratepayers' or their own, to resist this innovation?

7.5.2.3 ALTERNATIVE: Customer-specific information compiled by the utility which is linked to express agreements of use is customer proprietary; all else is utility proprietary.

Alternative 7.5.2.3 PRO

Electrical corporations, like businesses in every industry, collect information to perform business functions which enable them to survive. For all businesses, collected information can, at the time it is collected, be classified as belonging to either the collector or source of information. When the source of information places conditions upon the collector of information, dictating how collected information is to be retained and/or used, ownership and control over that information remains

with the source. Otherwise, ownership resides with the collector who has made the investments to acquire, store, and maintain the accuracy and reliability of the collected information.

As with other property rights, ownership of information property does not in itself allow for unrestricted use of that information. Rather, use of that information is subject to all laws, regulations, and professional rules of conduct applicable to its use, including those specific to consumer privacy as discussed in the balance of this chapter.

Following is a list of the information collected by electrical corporations which, when collected, have had conditions of use attached to them:

1. Information obtained through customer research surveys where participants were told their responses would only be used for specific purposes, and individual responses would never be disclosed for marketing purposes.

2. Information obtained through energy surveys or audits where participants were informed the information collected would not be used for marketing purposes.

All other information collected by electrical corporations is proprietary to them.

Alternative 7.5.2.3 CON

1. This distinction ignores the fact that the customers can have an interest in any customer-specific information that the utility has acquired since the customers reimbursed the utilities for the collection of that information through their rates. It may be that, if the customer specific information is used by the utilities for revenue generating purposes other than for which the data was collected, the customers should be compensated for such use.

2. Customers should be able to designate which information they want to release, in the same way that they are able to designate whether their telephone number is private or published. Additionally, customers should be able to authorize their energy service provider to release such information as is needed in the conduct of providing energy to the customer.

> 7.5.2.4 ALTERNATIVE: Customer specific information for an individual account — i.e., raw data — is owned by the customer. Aggregated, compiled or manipulated data of more than one account, even though they may be accounts of a single customer, belong to the UDC.

Alternative 7.5.2.4 PRO

(PG&E) UDC's may have established their own databases, and used their own resources, to forecast loads, make rates, plan system operations, or determine customer competitiveness in market. As long as sufficient barriers are in place as to not allow uncompetitive affiliate behavior (i.e. equal information distribution between energy service provider and affiliate companies), manipulated information should be the property of the utility. The utility should be allowed to charge a fair and reasonable price for the work done in manipulating the data and for its distribution. Shareholders and core customers shouldn't be burdened with this restructuring cost.

Alternative 7.5.2.4 CON

This creates a bottleneck for information flow with the UDC, thereby maintaining its monopoly power. New entrants should at least have access to the raw data, so they can manipulate it as they wish. In addition, see the arguments under Alternative 7.5.2.1 CON.

7.5.2.5 ALTERNATIVE: Ownership of customer information does not need to be fully resolved to accomplish the objectives of competitive restructuring.

Alternative 7.5.2.5 PRO

1. The customer and utility both have an ownership interest in customer specific information compiled by the utility. The ownership of customer information is shared by both the customer and utility, and is indivisible. However, the customer specific information in aggregate form is probably not constrained by ownership rights as such information doesn't identify specific customers.

2. Restructuring implementation efforts should instead focus on specifying the rights and responsibilities of all parties that collect, maintain, and use customer information, specifically as regards commercial uses of such data and protection of customer privacy. The notion of "ownership" by itself — i.e., without specifying the bundles of rights and responsibilities that comprise ownership — is too simplistic to be useful to the present restructuring process, yet its debate could absorb a lot of CPUC and stakeholder effort that would be better spent on practical implementation problems.

There is a need to spell out what the holders of customer data must, can and may not do with that data. As the last few sections should have made clear about this issue, positions of parties differ according to their relative emphasis on facilitating competition, protecting customers from possible harm, and protecting proprietary claims to the data. Depending on how the CPUC assesses and balances these three somewhat conflicting interests, it will need to define certain required, permitted, and prohibited activities for the collectors and custodians of customer data.

3. Resolution of ownership questions may take a long time. Fair access to customer information with adequate protection of customer privacy will have to be implemented in time to facilitate competition beginning in 1998, which means that practical details may have to be specified before all the ownership questions can be fully resolved. To look at it another way, specifying the rights and responsibilities of all parties is practically equivalent to specifying ownership. Taking this approach, the package called "ownership" may be distributed over a few different parties, rather than accruing to any single type of entity as it might if we tried to resolve ownership first.

4. A previous CPUC investigation raised the question of ownership of customer information, but did not need to resolve to accomplish its objective. In OII. 90-01-033, which was motivated by competition in telecommunications, the CPUC asked parties to address the question of ownership to determine "who can have access to the information, at what price it can be sold, and what should be done with the profits" (pp. 14-15). Parties' responses dealt mainly with specific rights and responsibilities and did not lead to attribution of ownership in general to any

one type of entity. Nevertheless the important practical questions of the investigation were resolved.

Alternative 7.5.2.5 CON

Attributing rights to and responsibilities over data is tantamount to determining who owns it under which circumstances. In establishing access, pricing, and revenue assignment policies, the Commission should give consideration to ownership rights to determine how best to allocate the value created by opening access to customer information. Ignoring clear ownership rights may otherwise lead the Commission to establish precedents which can be carried over into other areas of utility asset ownership rights.

7.6 Parties Eligible for Access to Information

7.6.1 Access Equality

According to the order contained in D. 95-12-063, utilities should provide qualified retailers with access to all customer information under the same terms and conditions used by utilities when providing access to themselves or their affiliates for marketing purposes. To prevent misuse of customer information, only qualified retailers should have equal access to it. Qualified retailers will be operating under codes of conduct specifically dictating how customer information is to be used, and misusing information should result in appropriate disciplinary actions. Retailer qualifications and codes of conduct are discussed in Chapter 6.

7.6.2. Recipient Eligibility

The issue raised in this section is whether or not each type of qualified retailer has the same access to customer specific information, and if not, what different protocols will govern each retailer class. For example, one retailer may qualify to provide generation brokering, another to provide energy efficiency services using PGC funding. Should each have the same protocols governing access to customer specific information? (See also the related discussion in Section 6.2.1 on CPUC jurisdiction over "electricity corporations.")

> POSITION: The same customer information access protocols should apply to all classes of qualified retailers.

PRO

Access to customer information should apply equally to both (1) generation retailers, and (2) energy service retailers using public goods charge (PGC) funding to promote energy efficiency market transformations. As has been successfully argued in past resource planning proceedings, provision of subsidized, market transforming energy efficiency services to reduce customers' energy use is as much an electric service option as is the provision of the commodity itself. Information access on an equal basis is necessary to meet the Commission's desire to neutralize natural advantages created from utilities' past monopoly roles in both facets of the industry. Any Commission decision pertinent to accessing customer specific information should therefore be applicable to the broadest definition of qualified energy service retailers.

CON

None submitted.

7.7 Rules Requiring Utilities to Disseminate Information

[Editors' note. Section 7.7 appears redundant, as it asks the Commission to consider a decision it has already made, namely, to require utilities to allow access to the customer information they possess. Some parties, however, wanted to make statements in this area, so in keeping with the policy of not deleting any controversial material we decided to let it stand.]

The Decision requires equal access to customer-specific information. What remains is the need to decide whether to require or possibly just allow utility dissemination of customer information to qualified retailers. Rules governing dissemination of customer information to other than qualified retailers, though not addressed by the Decision, should also be considered. Key factors affecting the Commission's selection of rules should include the effects they will have on competition, customers, and the health of the utilities and their competitors.

7.7.1 ALTERNATIVE: Rules should *require* utilities to release information to qualified retailers.

Alternative 7.7.1 PRO

1. In a restructured world, where either competition already exists or UDCs have no vested interest in protecting generation market share, an easy solution to creating equal access to customer information would be to prevent its release to any generation or energy service company. All competitors would then be treated equally. However the Decision clearly states that "some utility generation assets will remain under the ownership of the utility." (Decision, p. 85.) Under that condition, regulatory control over which information is made available to utility personnel representing both distribution and generation business interests at the same time becomes virtually impossible. Utility personnel will by default have access to information otherwise unavailable to both generation and energy service competitors. For that reason, the

Commission has made it clear that valuable information available to the utility as a generation competitor shall likewise be made available to all other generation competitors.

2. Potential UDC advantage is not eliminated by the requirement that utility generation sell into the PX and that the new UDCs buy from the PX for their full-service customers. The advantage is created by the competitive affiliate of the utility, or the UDC acting as a retailer or aggregator in competition with other non-affiliated retailers, having access to resources like customer information that enable them to unfairly retain customers.

Therefore, to neutralize the UDC's potential competitive advantage, the Commission must require UDCs to release the customer information to qualified retailers. Simply encouraging utilities to release information, even with incentives or rewards, does not guarantee information will be released. Instead, the decision will still be left with the utility. Rules and procedures for information release are therefore necessary to address how, not whether information is to be released, and should be developed in the early part of 1997.

Alternative 7.7.1 CON

1. Ordering paragraph 20 only requires the UDC to provide information to generation providers. UDCs should not be mandated to sell this asset but rather allowed to maintain ownership and control of this asset including the decision whether to sell. This information is not necessary, and is otherwise commercially available from other sources, for parties wishing to provide non distribution related services to customers.

2. In general, information which is considered non-personal (i.e., for which there are no privacy concerns), and which is gathered or developed by the utility in the course of performing its UDC functions, should be considered for release to all market participants. Rather than imposing a specific obligation on utilities to provide any non-personal information , the Commission should carefully develop guidelines governing the scope and procedures by which such information is released. Information release policies should take into account the value of the information, and the degree of administrative burden associated with its release. Guidelines are necessary to insure that neither marketers nor utilities abuse the process of releasing information. By developing guidelines, the Commission can deal with information release affirmatively, rather than as a result of protests by parties.

Once the Commission approves such guidelines, information which qualifies should be released to all parties, not just those who are qualified retailers. Once the Commission has concluded that a particular kind of information can be released without privacy concerns, and that it is reasonable for utilities to accept the administrative burdens of making such information available, there can be no legitimate reason to limit the release of such information in any manner.

3. Statements made by proponents regarding UDC s natural competitive advantage are not true, and should not serve as a justification for adopting the stated position. Under the terms of the

CPUC s Restructuring Decision, utility generation must be sold into the Power Exchange. UDCs must buy all the generation they provide to their non-direct access customers from the Power Exchange, subject to continued Commission regulation at the price charged by the Power Exchange. Thus, there is no competitive advantage that can be exploited by utility generating assets. Regarding unregulated utility generation affiliates, information transfers are addressed in utility holding company decisions and affiliate transactions manuals, and are subject to regulatory audit.

7.7.2 ALTERNATIVE: Rules should *encourage* utilities to release information.

Alternative 7.7.2 PRO

1. With regards to non-personal information which is gathered or developed by the utility in the course of performing its UDC functions, pricing and revenue ratemaking procedures that provide reasonable encouragement for utilities to participate in releasing information are likely to work better than command and control oversight.

2. Utilities may wish to develop business activities that involve aggregating, or otherwise processing customer information in ways that remove privacy concerns, yet are valuable to retailers. These activities go beyond the scope of the utilities regulated monopoly function, and they involve up front expenditures which, depending on the utilities business acumen, may or may not be recoverable from the sale of such aggregated information. In light of the associated business risks associated with such ventures, but recognizing that the customer information on which such activities derive results from the utilities monopoly activities, any profits from such activities should be subject to sharing between the utilities and their customers.

Alternative 7.7.2 CON

The Commission must *require* UDCs to provide customer information to all qualified retailers. Absent that requirement, UDCs would retain the option to choose to whom they provide information, and under which circumstances. Should a retailer be considered a threat, the UDC would be able to minimize that threat by denying access to valuable information. Allowing UDCs to retain control over the dissemination of information will prevent the Commission from achieving its desired objective of moving to a competitive market for both generation and energy services.

7.8 Obtaining Customer Consent

7.8.1 Introduction

The issue of customer privacy is founded on the claim of individuals, groups, or institutions to determine for themselves when, how and to what extent information about them is communicated to others. It has no foundation in ownership of information. Rather it addresses the degree of control that can be exercised by an individual over others' use of information about him or her.

Currently, utilities release customer data under various circumstances. Thus, the issue here is not whether utilities will make customer information available, but the procedure by which customer consent should be obtained. A procedure that requires a customer action to authorize release of information, for example returning a signed postcard, is called an "Opt-In" form of consent. A procedure that requires a customer action to maintain confidentiality is called an "Opt-Out" form of consent. In essence, these forms differ with respect to the default, i.e., the situation where the customer takes no action. Under an Opt-In mechanism, the default is *not* to release the information; under an Opt-Out, the default is to release it. The Opt-In is thus the stronger form of privacy protection, and typically generates much lower access rates than the Opt-Out.

Under some circumstances, customers need not be notified at all in advance of the release of information, and therefore no explicit or implicit prior consent is necessary. This procedure can be called the "No-Consent" approach. Obviously No-Consent will generate the greatest amount of customer information for potential electric service competitors.

In D. 95-12-063 the Commission has recognized that when information is used in ways other than originally expected by the customer, an invasion of privacy could result. It has therefore ordered that customer consent be obtained prior to release of proprietary or confidential customer information. For data requiring privacy protection, the Commission has stated that a customer must be notified in advance of the intention to release information to electric service providers, and be given an opportunity to deny consent. This principle rules out the No-Consent approach, but allows either an Opt-Out or an Opt-In to be used.

7.8.2 Procedures for obtaining customer consent to release information

There is a wide spectrum of possible procedures available to garner customer consent to release customer information. At one extreme is the No-Consent approach (no customer control); at the other extreme is the No-Access approach (no information release). In between are shades of consent that generally fall into either the Opt-Out or the Opt-In categories. Within each of these two categories there are implementation issues that could either foster or discourage customer responses. Following are the main procedures identified by the Direct Access Working Group, and discussions of advantages and disadvantages associated with each.

7.8.2.1 ALTERNATIVE: Non-personal customer information should be accessible without requiring customer consent.

Alternative 7.8.2.1 PRO

Non-personal information includes both individual and aggregate information that is not identifiable to an individual, business, or distinct group of individuals. Because customers cannot be identified from non-personal information, privacy and trade secret protections are not needed.

Non-personal information is useful to retailers for both planning and marketing purposes. Absent access to UDC compiled information, retailers would either incur higher costs to acquire the information through other means, or be forced to compete without the same level of customer knowledge enjoyed by the UDC when no other source of information is available. The price qualified retailers should pay for non-personal information is addressed in Section 7.11.

Examples of non-personal information useful to qualified retailers include appliance or equipment stock saturation and average load profiles for customers with specific appliance or equipment characteristics. Aggregation of small customers may be substantially boosted if aggregators have access to typical load profiles for various classes and subclasses of customers. In fact, at the June 26, 1996, meeting of the "Ratesetting Working Group" (formerly the "Unbundling and Rate Design Working Group"), some potential aggregators claimed the market would not be conducive to small customer aggregation without substantial customer data being available.

Alternative 7.8.2.1 CON

None submitted.

7.8.2.2 ALTERNATIVE: Non-sensitive personal information should be released to all qualified retailers without requiring customer consent.

Alternative 7.8.2.2 PRO

If the Commission's intent is to create an environment under which competition can best flourish, all non-sensitive personal information should be made available to qualified retailers without first having to get customer consent. Qualified retailers will be using non-sensitive personal information to perform the same services traditionally only available through electric utilities. Customers gave non-sensitive personal information to utilities with the expectation that it would be used to perform those services. Therefore it is not necessary to again require customer consent before releasing it to service providers who qualify to compete under the Commission's standards and regulations.

Use of sensitive personal information for the express purposes for which individual's originally intended eliminates the need to classify it as sensitive. Its use will not, when used for those purposes, seriously invade the privacy of individuals. It therefore can be categorized along with all other non-sensitive personal information.

For example, a retailer's use of personal information to market both energy management products and services (DSM) and electricity contracts (quantities, rates, and terms) is no different from the use of personal information by utilities today. There has been little objection by customers over the utilities' use of their names, addresses, account numbers, and usage history for those purposes, for example, in connection with DSM bidding programs. The Commission should therefore continue to classify those data elements as non-sensitive when used in ways previously open only to utilities, and should not require prior customer consent to release it to qualified retailers.

Alternative 7.8.2.2 CON

There is no example of non-sensitive personal information, i.e., personal information that would not compromise a utility customer's privacy. The customer's name is very compromising, especially if it is a full name which discloses the gender of that customer. An address is also sensitive. For example, many do not list their address in telephone directories and others only use PO Boxes to receive correspondence. But most importantly, any information given to the UDC in the past was so given with the expectation of full protection of the confidentiality of that information. And it was given to the monopoly because there was *no choice* in the matter, as there are no reasonable alternatives to monopoly electric service. Thus, the implicit contract with monopoly customers dictates that the personal information given to them should be treated as if it were sensitive.

7.8.2.3 ALTERNATIVE: Sensitive personal information may be released using an Opt-Out form of consent.

Sensitive personal information should be accessible to all qualified retailers with only tacit consent of the customer. An adequately noticed Opt-Out procedure, where the customer is given an opportunity to object to release of sensitive personal information, is sufficient to gain customer consent.

Alternative 7.8.2.3 PRO

1. As was pointed out in a February 1996 draft report from the Information Access Study Team (p. 20), legal control over information use by others is typically granted when resulting societal benefits are outweighed by the existence of all three of the following criteria: (1) there is a legally protected privacy interest; (2) there is a reasonable expectation of privacy; and (3) the expected invasion of privacy is serious in its nature and impact.

When determining which data meet these criteria, it is useful to focus on the third criterion first. If specific use of data does not create a serious invasion of privacy, it does not meet the last and therefore the full set of three criteria necessary to exercise control. Information that could

potentially create a serious invasion of privacy has been classified as "sensitive personal" information. Other customer-specific information that when used does not create a serious invasion of privacy is classified as non-sensitive personal information.

Unless information is determined to be sensitive personal information, there are no legal grounds that can be used to give individuals control over the use of others' information about them. Any establishment of such controls would therefore be strictly a matter of policy implementation.

2. In a restructured industry, unlisted telephone numbers collected by utilities have the greatest potential to be used in ways which (1) were specifically prohibited by individuals providing information to electrical corporations, or (2) could seriously invade the privacy of individuals without providing counter benefits to either the customer or society: The concern expressed by some is that unlisted telephone numbers acquired by qualified retailers would be used for intrusive telemarketing purposes. Providing customers with an opportunity to prevent their telephone numbers from being used in such ways would be adequate protection of individual privacy, where utilities and qualified providers are the only entities with access. All other personal information, when used by qualified retailers, is considered non-sensitive personal information. (Note that the specification of "qualified retailers" makes this situation different from a release of unlisted phone numbers to all parties.)

3. This mechanism will result in higher participation by customers than an Opt-In mechanism.

Alternative 7.8.2.3 CON

1. As a practical matter, Opt-Out is simply not good enough to assure that all customers have a meaningful opportunity to protect their privacy. Proponents of Opt-Out clearly recognize that more consumers will lose their privacy protections under this procedure than under an Opt-In procedure, because of how non-respondents are treated. We need to be sensitive to the reasons why consumers do not respond to a solicitation for information release. While there may be some consumers who do not care about privacy, yet would decline to respond to an Opt-In procedure, there are other consumers who, due to language barriers or inattention might inadvertently waive privacy protections that they consider important. With Opt-Out, nobody can really be sure.

2. The proponents inappropriately suggest that only telephone numbers should be considered sensitive. It should be noted that some consumers have their mail delivered to a post office box to retain the confidentiality of their address. Also, some consumers limit their telephone directory listing to their initials and last name, to disguise their gender. The Commission should not make any blanket generalizations about what information is considered sensitive, without considerable reflection on consumer needs.

3. With this mechanism, there is the potential for negative customer reaction. An Opt-Out mechanism maximizes the potential for inadvertent release of sensitive personal information.

4. A non-action by a customer should not be construed as an action in itself. There are many things that might not allow or compel a customer to send in an objection to information release, including: (1) time - the customer may not have the time or inclination to read the opt-out notice; (2) effort - customer may be too busy to respond; (3) delivery - customer may never even get the notice, it may be lost in mail; and (4) understanding - customers may not grasp the ramifications of the opt-out notice, and electric service providers may not have the incentive to educate them of the ramifications.

7.8.2.4 ALTERNATIVE: Sensitive personal information should require an Opt-In procedure for obtaining customer consent.

The UDC shall not release sensitive personal information to electricity retailers, energy service providers, or other agents of the customer without express authorization by the customer.

Alternative 7.8.2.4 PRO

1. A proactive action by a customer is clearly indication of interest in a program. Customer education is critical to stimulate this interest and a opt-in notice will encourage energy service providers and other participants to actively educate the market. With an opt-in notice, there is verification that the customer has read, and presumably understands, that personal information will be released, because a person will generally not sign a consent without understanding what it means.

2. The opt-in notice is also consistent with the philosophy that the customer owns its own account information. Nobody should be allowed to dispense information owned by another without specific authorization to do so.

3. As the Commission affirmed in its CNEP program, utility customers have the right to expressly release personal information. Opt-out or "negative check-off" arrangements exploit most consumers inability to process all information provided to them. For this reason, such arrangements are generally discouraged in state law.

4. An opt-in procedure should be designed to elicit maximum customer response. The maximum amount of customer information should be available to competitors in order to facilitate the transition to a competitive retail market. At the same time, customers must knowingly consent to provide personal customer information to competitors (opt-in).

5. Most customers are unlikely to respond to a privacy designation process, and specifically to opt-in. This lack of response does not necessarily mean that customers would be unwilling to provide information to competitive electric service providers. It simply means that inaction and inertia are the predominant response to utility communications, particularly if those communications fail to establish awareness and understanding.

6. The objectives for the $33 million Customer Notification and Education Plan (CNEP) for Pacific Bell's caller ID program are instructive. Caller ID required affirmative customer action in order to select the option that provided greater privacy protection, that of per-line blocking to prevent number identification. In contrast, an opt-in procedure allows the customer to do nothing, and maintain maximum privacy protection. Hence, it is likely that caller ID would elicit greater customer response than an opt-in procedure for electric restructuring. The Commission's consultant framed a 30 percent objective for customers taking action as realistic, but aggressive. In other words, we can expect that upward of 70 percent of customers will not opt, either in or out. (See "Evaluation of the October 11, 1995 Pacific Bell Customer Notification and Education Plan on CPN Delivery," Brenda Dervin, p. 22.)

This has two implications. First, the characteristics of the default option are the most important. Secondly, to achieve an objective of maximum informed customer consent will require resources and creativity.

7. Although aggregate customer information is an imperfect substitute for individual information, aggregate information can provide significant knowledge of potential target markets to competitors. The dividing line between aggregate and customer-specific information is still under discussion and needs to be carefully defined. While there should be broad disclosure of aggregated customer information, individual customers should be able to control contacts as a result of that disclosure. Specifically, customers could designate their willingness or lack thereof, to entertain mail and/or telephone marketing material.

8. It appears that the CNEP gathered a significant amount of baseline material to assess what customers already knew, and how customers might respond to communication. Since electric restructuring involves both privacy considerations, as well as widespread industry change, the privacy designation process merits a comparable effort.

9. This effort could overcome several obstacles to customer response. Some reliance on bill inserts will probably be necessary. Customers tend not to respond to bill inserts for several reasons. Historically, inserts provided information that was difficult to understand; if customers could even act upon the information, it has often been unclear how they could do so. These obstacles can be overcome by designing simple, clear inserts, and testing those inserts for customer response.

10. An education effort should also consider means other than bill inserts. For example, a separate mailing may elicit a higher response rate in general. Alternatively, a separate mailing might be considered for non-respondents to an initial bill insert.

11. The more value an action has, the more likely people are to take action. Some of the recommendations in the consultant's CNEP report are for various inducements for those who respond. (Dervin, op cit, p. 31.) There are several ways to enhance benefits. One is addressed in

section 5.8.1, and pays customers for the value of information about those customers. Since privacy is a significant concern of many people, increasing the privacy benefits of taking action is attractive. The Mail and Telephone Preference Services of the Direct Marketing Association allow customers to inform many sellers at one time that they do not wish to receive mail and telemarketing calls respectively. Since millions of Californians requested per-line blocking, but national enrollment in the Telephone Preference Service is under a million nationwide, privacy options that extend beyond electricity could increase response rates.

Alternative 7.8.2.4 CON

1. The Opt-In mechanism will result in lower customer access to competitive alternatives than any other mechanism. Far fewer customers who would benefit from competitive alternatives will take the time to investigate what it means to Opt-In, and then proactively respond to the Opt-In procedure. It takes time to investigate alternatives, especially those which by the very nature of the Opt-In mechanism indicate that there must be something potentially harmful with responding. If responding isn't potentially harmful, why would the Commission require this process?

2. It is also unnecessary to require customers to give their consent to release and use information for purposes specific to an industry which is heavily regulated. The electric industry is one which has regulatory oversight of existing utilities. If the Commission also establishes regulatory oversight of qualified retailers performing traditional utility services, the Commission will retain control over how utility collected information, used by all competitors for the provision of electric services, can be used.

3. Asking customers to provide explicit consent is only appropriate when the Commission discharges its regulatory responsibilities, which it should not. By retaining its regulatory responsibilities over these facets of the electric service industry, the Commission will be able to ensure only reputable companies have access to sensitive personal information. Also, the Commission will be able to take corrective actions should any party misuse sensitive personal information. These controls are the same in place today for overseeing utility service, so little will change if the Commission chooses instead a less restrictive procedure for customer consent for sensitive personal information.

7.9 Mechanisms for Information Release

For the sake of concreteness, this section will focus on the near-term problem of releasing utility-held customer information to eligible retailers to facilitate meaningful competition by 1/l/98. The near-term involves release of only utility-held data. It does not consider a later stage in which the custodians may be more diverse parties; the mature market scenario is discussed in Section 7.13.

This section lays out options for the actual transfer of customer information from utilities to retailers. Whatever options are selected, they all have in common the need for utilities to create from their existing data bases a new data base that will be accessible by retailers. Such a data base could contain all categories of data discussed in Section 7.4 — personal and non-personal, and individual and aggregate.

Criteria which should guide the choice of an information release mechanism include: prompt release to all qualified retailers; user-friendly data format; implementable in 1997; cost effective; and, compatible with appropriate customer privacy protection.

7.9.1 One-Time or Continuing Release

For implementation in 1997 the Commission might consider a one-time window of access, to begin in the latter half of 1997 and last for a well-defined period of time, perhaps as short as a month or as long as a year. Any electric service provider who was qualified before the end of that period would be eligible to receive customer data. Under this option the utility would prepare a data file from its records only once, and that file would be given to all providers.

Alternatively, the Commission might wish to specify an open-ended period to continue during the transition to a mature market. One objective might be to create incentives and conditions at the beginning that would stimulate the evolution of societally efficient information-management arrangements for the mature market. Under this option the utility would design its accessible customer data base to be updatable.

These two ideas are conceptually not mutually exclusive. A finite window of access could be an experiment to inform the design and implementation of later phases of information access. It would enable the Commission to assess the satisfaction of all parties with the process and to correct problems. To be really useful as an experiment, however, it would probably require that the accessible utility data bases be updatable.

7.9.2 Electronic Bulletin Board (EBB) or Standard Floppy Disk

The features of an EBB include: updatable monthly with easy dissemination of updates; retailer access by password; retailer who accesses EBB leaves a footprint; near zero marginal cost per additional EBB user.

Standard Disk is perhaps the simplest option from the viewpoint of data distribution. The utility would create a standard data base for one-time release to qualified providers, and all providers would receive that data base on disk. No updates would be required for this phase of the information access regime.

7.9.3 Energy Service Fulfillment House

The mechanisms discussed above all involve direct release of information to eligible retailers. An alternative would be to create an information intermediary, a fulfillment house similar to the kind used in direct mail retailing. The fulfillment house option places greatest emphasis on customer privacy by being the sole authorized entity to have possession of customer data bases. Retail providers would deliver their promotional material to the fulfillment house to be mailed to a set of customers with specified characteristics. The fulfillment house would identify the desired customers from the data bases and send them the material. This option is discussed more fully in Section 7.12.

7.9.4 Combined Arrangements

Because of the variation in sensitivity of customer information, it may be desirable to develop a combination approach to customer information. Non-personal information, for which privacy is not an issue, could be released to eligible providers on disk or through an EBB. This kind of data would be valuable for market analysis, but would not be helpful in identifying customers the retailer might wish to contact. Customer contact could be performed by the fulfillment house, so that customer ID is never released in combination with usage, billing, or other personal data. See Section 7.12 for further discussion of specific options for near-term information access.

7.9.5 Utility or UDC Role in Administering Information Access

Like other aspects of information access, the utility or UDC role needs to be assessed in terms of both the near term (to facilitate competition by 1/1/98) and the long term (information access in the mature market). For the near term it makes sense to give utilities a substantial role, as the data in question are in their possession. However, it is not obvious how large their role should be. For example, if the utilities are required to release customer data to competitive retailers, and if they are to be responsible for obtaining necessary customer consent for such release, then should they also be responsible for educating customers about their privacy rights and the implications of consenting to data release?

Although consumer education is not the topic of this chapter, it is clearly intertwined with the problem of consent to release information. For any particular consent mechanism, there may be vastly different numbers of consenting customers depending on the style and format of the education materials. The Commission should therefore consider the utility role in information access from a systems viewpoint, to include customer education, obtaining consent where necessary, formation of the data base to be released, and actual turnover of information to eligible recipients. Section 7.12 discusses some more comprehensive scenarios.

For the long term, the utility or UDC role cannot yet be determined. One could imagine a large role for the UDC if that entity is the only custodian of information that has comprehensive data on all customers connected to the distribution network. Alternatively, it may be desirable for industry participants to develop an entirely new information management regime in which the central custodian of customer records is an independent entity that collects all metered data and provides information services to the ISO, PX and UDCs for operations and settlements and to competitive retailers for billing, product development and marketing. These ideas are developed more fully in Section 7.13.

Following are different utility administration role options identified by the Working Group.

7.9.5.1 ALTERNATIVE: Utilities should not be required, but instead should be encouraged to administer customer notification and selection of applicable consent choices.

Alternative 7.9.5.1 PRO

The opt-in or opt-out procedures suggested by some workshop participants place upon the utility a responsibility to serve as a form of market information clearinghouse. That is, the utility would need to add information to its existing customer information database regarding whether individual customers consider their information to be confidential, and then develop procedures to extract information from this database on request. Procedures would need to be developed to gather and validate confidentiality information from both existing and new customers, to update records, and correct errors. Carrying out this responsibility could be expensive, and may require customer support (in distribution rates), since there is no assurance that the resulting product would be cost effective for marketers to purchase.

Maintaining an ongoing opt-in or opt-out procedure should be distinguished from a one-time solicitation of customer interest in being included in a customer list provided to retailers. Such an approach, which could be undertaken by the utility prior to the commencement of direct access, would involve a "snapshot" extract of customer information for consenting customers, and would be administratively simpler than an ongoing process.

It would be better to leave the development of an information clearinghouse function to the market. Once the direct access marketplace has developed, there is no reason why retailers can't perform their own confidentiality waiver procedures, and turn the information they gather over to a third party. Utilities may wish to be involved in such a function, but if so, this involvement should be at shareholder risk.

Alternative 7.9.5.1 CON

None submitted.

7.9.5.2 ALTERNATIVE: Utilities should be required to administer customer notification and selection of applicable consent choices.

Alternative 7.9.5.2 PRO

As a default (absent any other solution), utilities, and later UDCs, should be responsible for administering any applicable customer consent procedures. However they should not be responsible for the costs associated with this process. The Commission should consider alternative sources of funding to reimburse utilities for their efforts.

Alternative 7.9.5.2 CON

Although the utility has information on where to send its bills and to whom, this address and addressee may not be appropriate for this distribution. For example, for a chain account, the individual store owner may not be authorized to make this decision for the company and may not be able to get a response timely enough from its corporate office to prevent the release of information.

The utility should not be saddled with either the administrative or cost burden, and the potential negative customer perception, that will go along with an some consent procedures. Depending on the procedure selected, an intensive customer education effort may be required. The energy service provider should also take responsibility to provide this education to the market.

7.10 Business Conduct Issues

7.10.1 Marketing practices of retailers who receive customer information

Competition in telecommunications has seen the occurrence of a number of intrusive or unethical marketing practices, including aggressive telemarketing and slamming. In anticipation of similar tendencies in the electric services industry, the Commission should identify those practices to be limited or prohibited, and impose appropriate rules upon recipients of customer information. Any violation of the rules may be punished by loss of license and punitive damages. For a full discussion of market rules and their enforcement see Chapter 6 of this report.

7.10.2 Guaranteed access by customers to their own data

7.10.2.1 ALTERNATIVE: Customer information collected by competitive retailers must be made available to the customers themselves, or to their authorized agents, promptly and in a usable format.

Alternative 7.10.2.1 PRO

Customers must have access to information from their own data records, for at least two reasons. First, that information may be useful to them for making decisions to change their energy usage patterns, to install new equipment, or to change suppliers. Second, they must have the right to ensure that their credit histories and other sensitive records are error free. In addition, customers must have the right to authorize access to some portions of this information for any other party they deem appropriate.

At the request of a customer, a retailer or UDC shall provide the customer's usage information (for a reasonable historic period) to another retailer, the UDC, or energy service provider. The price of such information, if there is such a charge, shall not exceed the reasonable cost to the provider of supplying such information.

Alternative 7.10.2.1 CON

Only customer information which both the customer and retailer agree is transferable should be available to customers or their assigned agents. Retailers will be compiling information about their customers that will become trade secrets to the retailer. If given to other retailers or the UDC, a retailer's competitiveness could be compromised. It will be important for customers to identify, before signing any retailer agreement, which data will be transferable to others.

7.10.2.2 ALTERNATIVE: Retailer-collected information must be made available only upon both customer and retailer consent.

Alternative 7.10.2.2 PRO

Retailer collected information is proprietary to the retailer. Customers choosing direct access and other energy services from retailers should work with their retailers to determine what information, upon termination, is transferable to others. Because retailers in the early stages of restructuring will be at a competitive disadvantage, the rules applicable to utilities and UDCs should not be applicable to retailers. Rather, the Commission should recognize and protect the proprietary rights of retailers to enable them to flourish.

Alternative 7.10.2.2 CON

Just as one would reasonably expect the UDC to provide historic information about a customer transferring service to a retailer for use in load forecasting, there should be a similar expectation

when a customer transfers from one retailer to another. The Commission should not foreclose the option for developing retailer-to-retailer information transfer requirements.

As long as the customer doesn't enter into an agreement with the retailer giving up his rights to his customer data, the customer data belongs to the customer.

Retailer-*collected* information about a given customer or account should not be seen as proprietary to the retailer (or for that matter to the UDC). Such *collected* information includes names, address, and periodic energy usage. Retailer-*manipulated* information (such as analyses of usage patterns, multiple customer or account databases, or any other product requiring analysis beyond mere collection of data) should be seen as proprietary, and should be available only upon retailer consent.

7.10.2.3 ALTERNATIVE: The UDC should provide personalized energy use profiles to its customers.

In order to effectively comparison shop, customers will need to understand their energy consumption patterns and history of usage. Customers essentially want to know "how much money will I save?" However, the answer is not arrived at easily. In order to answer, the electric customer needs energy usage history, data from comparable periods of the current and at least one previous year, adjustment for weather fluctuations, adjustment for price changes, comparison to other customers' energy usage and breakdown of expenses for major appliances. (See: W. Kempton, Improving Residential Customer Service Through Better Utility Bills, ESource SM-95-1, August 1995). It is unreasonable to expect that customers have saved their bills over the previous three years in order to secure this information. However, UDCs have collected a certain amount of historical data about its customers that can be used.

The UDCs should be ordered to provide, upon request, an energy usage profile for an individual customer. Costs to provide this information should either be reimbursed by the customers or through cost recovery mechanisms that encourage UDCs to perform this function proactively. Profiles could include a chart and breakdown of monthly data for energy consumption and price paid for energy over the previous 12-24 months, depending upon the information storage practices of each UDC (typically, utilities save 13-18 months of customer usage data. It should be adjusted for weather and price changes. It should also include a comparison to other representative customers' data so as to provide a benchmark against which to a customer can compare his/her usage. The first energy profile should be offered at no cost to customers. Modest charges may be applied to subsequent profile requests.

This profile will be the basis upon which customers can gauge their historical energy consumption patterns, better assess their energy needs and gain a sense of the cost of that electricity. This profile could be released by the customer to retail energy companies to better enable them to choose

appropriate services for that customer. Or it could be the same information provided without prior customer consent to enable retailers to effectively compete against in the market.

Alternative 7.10.2.3 CON: Forces the UDC into a business — creation of usage profiles — that it may not want to be in. It may be better for customers to obtain raw data from the UDC and then have a third party create its usage profile. The customer should pay the costs of obtaining its raw usage data.

7.10.3 Dissemination or sale of customer information by retailers

Competitive retailers who collect and maintain customer information should be subject to rules of custodianship that protect customers' privacy and trade secrets. However questions remain as to (1) the precise consent requirements to impose on private retailers, (2) the authority of the CPUC in such matters, and (3) the means of enforcement. At one extreme, the Commission might require only that retailers send customers notice of their intent to disseminate information, with a reasonable time period for the customer to respond and opt-out. At the other extreme, retailers may be required to obtain explicit customer consent to release information to another party. Following are positions identified by the Working Group.

7.10.3.1 ALTERNATIVE: A retailer's release of personal information would only be allowed if the customer has given a *meaningful* waiver of privacy protections.

Alternative 7.10.3.1 PRO

A retailer's intent to release personal information must be adequately disclosed to the customer, to prevent unauthorized or abusive use of personal information.

Alternative 7.10.3.1 CON

None submitted.

7.10.3.2 ALTERNATIVE: Retailers receiving customer information from UDCs must utilize an opt-in method for determining which information may in turn be released or sold.

Alternative 7.10.3.2 PRO

Utility customers must expressly choose to have any protected information released by the utility. Such affirmative control of personal information should also pertain to other energy service providers, but it may exceed the Commission's jurisdiction to so require. However, if an energy service provider takes advantage of access to utility-held information, then that provider

must, as a precondition to such access, agree to obtain explicit customer consent to use that information for any non-energy matters such as release or sale to another entity. Providers may periodically offer customers an opportunity to opt-in to a release of their information, and may offer incentives to opt-in. However, under no circumstances may the retailer release protected information if a customer fails to respond.

Alternative 7.10.3.2 CON

None submitted.

7.10.4 Privileged Access to Utility Customer Data by Competitive Affiliates

This section has two parts. The first contains a position statement on the need for market rules to prevent privileged access to customer data. Such rules may be incorporated in the general set of Market Rules discussed in Chapter 6. The second contains a position statement on the need for up-to-date, formal statements by the utilities on their policies and practices in this area.

7.10.4.1 ALTERNATIVE: The Need for Market Rules to Prevent Privileged Access

A competitive electric services market needs enforceable rules to prevent privileged access to data maintained by a regulated utility.

Alternative 7.10.4.1 PRO

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

Earlier sections of this chapter have discussed the principal mitigation for this utility advantage, namely, a fair access regime that will allow all competitors to have access to the same information on the same terms. The present section raises a parallel concern: how to prevent competitive divisions or affiliates of the utility, or any other party for that matter, from having privileged access to customer information.

Potential UDC advantage is not eliminated by the requirement that utility generation sell into the PX and that the new UDCs buy from the PX for their full-service customers. The advantage is created by the competitive affiliate of the utility or the UDC acting as a retailer or aggregator in

competition with non-affiliated retailers for the same customer base, having access to resources like customer information that enable them to unfairly target and market to choice customers. (This possibility could, of course, be mitigated if utility-affiliated retailers were precluded from operating in their affiliated utility's service territory, as argued in Section 6.5.3.)

There are at least two reasons why this issue needs explicit attention and is not adequately mitigated by implementing a fair access regime. The first has to do with the proposed schedule of restructuring. Rules of fair access being developed now are still far from implementation. Meanwhile the marketing departments or retail affiliates of the utilities may have privileged access to customer information which could give them a head start over competitors. If competition is to be meaningful in 1998 then head starts to incumbents need to be minimized.

Second, it is likely that only a portion of the data contained in utility customer data bases will be made available to competitive providers. Even after the transition to a mature market, the utility will continue to maintain other customer data which is not released to other providers but which could still be useful for marketing and product development. The potential thus exists for unfair advantage to the utility's own retail activities.

So long as utilities are permitted to transfer personnel from their regulated to their unregulated businesses, there will continue to be unfettered transfer of competitive information that is not accessible to the utilities' competitors.

Alternative 7.10.4.1 CON

Section 7.2.5.1, which is a consensus position, establishes a principle that UDCs will provide equal access to customer information used for marketing purposes to all retail entities. UDC transactions with affiliated retailers are governed by "holding company" standards and subject to audit by regulators. Thus, the proponents' statement that "rules of fair access ... are ... far from implementation" is simply not true.

The proponents express concern that a UDC's "competitive divisions" will somehow gain a head start in competing with unregulated retailers as a result of using confidential customer information for marketing purposes. This ignores the restrictions imposed on utilities by the Restructuring Decision, particularly a requirement that distribution utilities meet the energy requirements of their full service customers entirely from Power Exchange purchases. (See the Restructuring Decision, p. 51; also pp. 71 and 97, which restricts contracts between the distribution utility and affiliated generation. These are requirements that apply during a transition period.)

7.10.4.2 ALTERNATIVE: An Immediate Need for Formal Utility Statements

To facilitate competitive direct access beginning in 1998 the CPUC should, as soon as possible, require the incumbent utilities to file statements of their policies and practices regarding access to customer information in their possession.

Alternative 7.10.4.2 PRO

An open CPUC order issued in D. 90-12-121 requires that energy utilities notify the Chief of the Energy Branch of CACD 90 days in advance of an intended change of policy regarding use and dissemination of customer information. That decision dismissed the energy utilities from OII. 90-01-033, which had been opened to address access to customer information in the competitive long-distance telephone market. The CPUC dismissed the energy utilities on the assessment that, first, their stated policies and practices were appropriate for a non-competitive environment and, second, precluded commercial use of the data by the utilities themselves or their subsidiaries and affiliates.

Now that the electric services environment is becoming competitive there is ample motivation to revise the practices stated by the utilities in 1990. In fact, the customer retention activities of utility sales and marketing departments (see Section 7.2.1 and Figure 7.1 of this report) may be indicative of utility use of customer data for commercial purposes. Accurate, formal statements of current utility policies and practices, and any intended revisions to them, are needed now.

Alternative 7.10.4.2 CON

Energy utilities were respondents to I.90-01-033, and filed statements regarding their policies and practices. One utility presented its current practices to the workshop. The issues raised in this chapter directly address utility practices regarding customer information. It is unclear what proponents of this statement are seeking to achieve. At this point, making formal statements appears superfluous, and inconsistent with the use of workshop processes.

7.11 Price Charged by Utilities for Customer Information

As access to customer information increases, UDCs may seek to charge for the service of supplying such information. Going beyond basic access to metering and billing data, UDCs, competitive electric retailers, and non-profit entities may want to develop a business of performing studies that aggregate or analyze customer data in a manner that protects individual confidentiality, yet provides insights into customer characteristics, that are useful to competitive electric retailers. It is not clear what ratemaking practices would govern the disposition of proceeds from such a business venture. Following is a discussion of the options identified by the Working Group.

7.11.1 ALTERNATIVE: Customer information should be sold at a price equal to the incremental cost of providing the information, as determined by the CPUC.

Alternative 7.11.1 PRO

To encourage efficient competition, information should be made available to all competitors at the lowest possible cost. However providing information to competitors at a price below the incremental cost of producing it would place an unnecessary burden on the provider of information, and may actually cause the provider to be less effective in disseminating information to avoid the negative consequences. Therefore, to encourage the greatest dissemination and use of valuable information, and consequently maximize the opportunity for competition, the Commission should require UDCs to provide information at a price equal to their incremental cost of production. The Commission should determine how to calculate the incremental cost of information production by ruling on options provided to it by future working groups tasked with defining costing alternatives.

Alternative 7.11.1 CON

Pricing at incremental cost may be appropriate in some circumstances. However, where there are substantial fixed costs associated with information systems, pricing at incremental cost may result in unnecessarily subsidizing retailers.

7.11.2 ALTERNATIVE: Customer information should be sold at no higher than fully allocated costs, unless the CPUC determines that sufficient competitive alternatives exist to allow market pricing.

Alternative 7.11.2 PRO

This position is not necessarily inconsistent with using incremental cost as the basis for pricing, but provides greater flexibility for the Commission to set pricing policies based on factual circumstances unique to the information markets in question. While it may not be likely that competitive information markets will develop, as a general proposition, price regulation by the Commission should be relaxed or eliminated if retailers or third parties develop ways to obtain and market customer information.

Alternative 7.11.2 CON

There are two scenarios: 1) the release of account specific raw data to a customer, and 2) the release of the manipulated or compiled data of more than one account. Under the first scenario, the information belongs to the individual residing at the account location. Currently, the customer does not pay to have its account usage history released to it. This practice should

continue, excepting the possibility of a premium being paid to the UDC for short turnaround of its request. (Its very possible that the UDC will be inundated with such requests. To provide such turnaround would likely require the UDC to operate outside its normal course of doing business. This service should require an added cost to the requesting party.)

Under the second scenario, the UDC owns the secondary or refined information that has resulted from its manipulation of the data. The UDC should be allowed to charge a fee for providing this processed information.

7.11.3 Disposition of Revenues from UDC Sale of Customer Information

7.11.3.1 ALTERNATIVE: Any revenues resulting from UDC provision of customer information should be returned to the individual customer whose information was provided.

Alternative 7.11.3.1 PRO

This revenue treatment logically follows from customer ownership of information. However, even if customers are denied ownership, customers are entitled to the revenue from the provision of customer information. Finally, a logical implication of customer control of information is that providing incentives to customers to make information available will benefit competition.

Restructuring will lead to the expansion of competitive markets for electric services. Expanded markets increase the monetary value of marketing information, such as customer information. The claim of customers to increased value is superior to that of utilities. First, customers have been assigned the full cost of the transition to competition in the form of competition transition charge (CTC). The CTC is likely to dwarf the increased monetary values of information. There is no apparent justification for customers to bear only liabilities, and not any corresponding assets of the transition competition.

Some utilities claim at least a potion of information provision proceeds due to their significant efforts to store and maintain accurate and reliable information. However, any utility investment in order to carry out monopoly utility functions has already been included in revenue requirement. To the extent that utilities have invested in customer information systems for business activities beyond traditional regulated utility activities, then rates to carry out regulated activities were too high.

Assignment of information revenues to customers also benefits competition and should enhance the success of Commission restructuring efforts. The more information which is available to competitive providers, the more that providers can tailor their products to customers. Providing

monetary inducement to individual customers should increase the quantity of customer information available, relative to alternatives.

The assignment of information revenues to individual customers should also affect broad attitudes to changes in the electric industry. Assignment to individual customers provides at least one positive answer to the common question of "what's in it for me?" The provision of a customer specific benefit is also far more noticeable to customers than a revenue credit embedded in rates. In contrast, under the present phase-in schedule, many customers may not recognize any choice or benefits, at least during the first year.

Direct provision of information revenues to customers is something new, and attention-getting in a way that the ability of select different generation providers is not. Customers already have choice for almost every product. In that sense, electric choice is simply an extension of an existing, broadly practiced concept. Customers rarely receive payment for information. That new concept should draw greater, and more favorable, customer attention and awareness of electric restructuring.

If the customer information is sold at a price that is above incremental cost the net revenue should be returned to the customer. But since such a reimbursement would result in added transaction costs, it is probably more efficient to deduct the net revenue from the customer's bill than to return the net revenue.

Alternative 7.11.3.1 CON

The proponents are certainly correct in observing that direct customer payments for information usage is something new. The administrative burdens of implementing a regulated program for providing direct customer payments are likely to be daunting, and the associated administrative costs might very well overcome the proceeds from selling customer information. There were a few examples of telephone retailers providing inducements to customers to waive confidentiality, discussed in the workshop. It is best for the Commission to leave such market experiments to the unregulated market, and not attempt to use regulation to force the development of such mechanism on the UDCs.

7.11.3.2 ALTERNATIVE: Net revenues from the sale of customer information should be retained by the UDC, subject to the net revenue sharing and any periodic reviews of Performance Based Ratemaking mechanisms.

Alternative 7.11.3.2 PRO

Traditionally, utilities have engaged in miscellaneous business activities, such as leasing land under transmission lines to nurseries. Revenues from such activities are booked as "other operating revenue", and serve to reduce utility rates. (Other Operating Revenues are forecast in

GRCs, and shareholders are at risk for achieving the adopted forecast.) Under PBR, utilities have substantial flexibility to develop creative opportunities to improve the utilization of utility assets. PBR mechanisms typically allow shareholders to retain all other operating revenues so long as overall earnings remain within a net revenue sharing dead-band, and a and a portion of such revenues outside the dead-band. This provides strong incentives for the utilities. In the short-term, customers benefit from net revenue sharing. In the long-term, such opportunities allow the Commission to establish more aggressive "productivity targets" for the utilities, so such benefits are ultimately passed on to customers.

Alternative 7.11.3.2 CON

If the customer information is sold at a price that recovers the UDC's cost, there should be no net revenues to be retained as a result of the sale of customer information. Allowing the sale of customer information that results in large net revenues is inconsistent with the Commission's goal of facilitating competition.

7.11.3.3 ALTERNATIVE: Net revenues from the sale of customer information should be returned to customers, via ratemaking procedures that reflect recorded, rather than forecasted, net revenues.

Alternative 7.11.3.3 PRO

The justification for customers receiving revenue is the same as for Section 7.2.10.3.1. Ratemaking credits are a well-established ratemaking procedure. The provision of customer information is similar to the category of "other operating revenues", *i.e.*, revenue not strictly related to the provision of regulated services. Many such revenues are forecasted based on historic trends. The provision of customer information is a new service, for which there are no historic trends.

While ratemaking credits are well established, the Commission's Decision introduces new ways of setting rates, including the rate cap. Since information revenues have never been part of bundled service rates, the information credit should be a further deduction from otherwise applicable rates.

Alternative 7.11.3.3 CON

Using flow-through ratemaking for information revenues represents a return to the kinds of "command and control" ratemaking practices that the Commission is seeking to avoid by encouraging utilities to develop PBR mechanisms for those portions of utility activities which will remain under regulation.

7.12 Options for the Near Term

7.12.1 Options for a One-Time Release of Customer Information Prior to 1/1/98

CPUC Decision D.95-12-063 recognizes the marketing value to competitive electricity suppliers of the customer data presently in the custody of the investor-owned utilities. To support the objective of facilitating healthy competition, the Commission orders the utilities to make that data available to their competitors. At the same time, the Commission expresses concern for the privacy of customers and orders that customer consent be obtained prior to the release of such data to competitive suppliers.

Implementing the CPUC's order requires that we strike a societally efficient balance between the needs of the emerging marketplace and the privacy rights of utility customers. This section offers two feasible approaches for achieving such a balance. The options described below should be thought of as "one-time releases of" or "windows of access to" utility customer data. As such they have two major objectives: 1, to facilitate a direct access market that will reach all classes of customers on 1/1/98; and 2, to assess the importance of customer data in this market and evaluate the strengths and weaknesses of whichever option is implemented.

7.12.2 ALTERNATIVE: Release Data Directly to Qualified Providers

Under this option, customer data would be provided to qualified energy service providers during a specific time period or window which begins prior to 1/1/98. The utilities would produce a standard data base including, for those customers who give the necessary consent, customer name, service address, billing address, phone number, rate class and the last 12 months energy consumption in whatever form the utility possesses for each customer (i.e., monthly totals, time-of-use subtotals, or load profiles).

(Note: Release of telephone numbers may be controversial. The opening of competition in long-distance phone service has seen abundant complaints about intrusive telemarketing. Also, it may be impossible for the utilities to tell which of their customers have unlisted telephone numbers. Customer consent may therefore be more of an issue if telephone numbers are to be released.)

The certification or registration procedures established for generation service providers or other energy service providers would confer eligibility for access to customer data. Access to customer data would carry prohibitions on further dissemination of the data and undesirable marketing practices. Any party who felt a violation had occurred would have ready access to an impartial venue for resolution, and providers who obtained the data would be required to demonstrate insurance or post a bond to cover assessed damages. These mechanisms would constitute one aspect of customer privacy protection. The other main aspect would be the customer consent procedure.

Once the CPUC determines the numbers of customers in each class that may participate in direct access in 1998, some form of solicitation of customer interest will need to take place. Following an education campaign, customers could be asked to return a signature card that would express both their desire for direct access and any necessary consent to release data. Once the final pool of eligible customers was selected, only those customers would be part of the data release no matter how many more might have returned the signature cards.

Alternative 7.12.2 PRO

1. Customer data essential for aggregation of residential and small commercial customers would be available to potential aggregators of those customer classes.

2. The data would be released only to qualified energy service providers who would be liable for damages resulting from misuse of the data.

3. Release of consumption data would benefit the residential and small commercial customer classes as a whole by facilitating aggregation of load for these classes.

4. The release of consumption data would promote efficient marketing practices by enabling providers to target specific customers who match their marketing profile and avoid those who do not.

Alternative 7.12.2 CON

1. Some customers might actually have their privacy compromised by inappropriate use of the data, thus provoking lawsuits against the firms involved.

2. The data could be used by some firms to avoid customers in areas or with usage patterns they did not wish to serve, thus increasing the possibility of "redlining."

7.12.3 ALTERNATIVE: Release Data to a Fulfillment House

Under this option, which is a variation of a standard practice in the direct mail industry, customer data is not released directly to competing providers. Instead it is released only to a special type of entity, a fulfillment house which performs a marketing function for competing providers and which is governed by the same use limitations and bond requirements discussed in the previous section. The energy service providers would be given only impersonal data, such as aggregate consumption and typical load profiles without customer identification. The firms would then develop marketing literature for a target customer group and turn this over to the fulfillment house which would, in turn, mail the literature to the target group.

The energy service providers would not have any personal customer data until such time as the customers responded to the marketing literature and authorized the fulfillment house to release their data to the energy service provider(s) they designate. Energy service providers and the fulfillment house would have to work together to determine how the marketing strategy of the potential provider would interact with the customer data to identify the specific customers to which the mailing of literature would be made.

Alternative 7.12.3 PRO

1. Customer privacy would be maximally protected since customers can select those providers they wish to receive their customer-specific data.

2. The fulfillment house, as a specialist in sorting customers into target groups and mailing out marketing literature, would develop efficiencies and economies of scale that would enhance the efficiency of information flows and of the marketplace in general.

3. The fulfillment house created to support the 1/1/98 opening of direct access would be a useful prototype for a stand-alone clearing house for customer data, which is a potentially attractive information management institution for the mature, competitive marketplace. (See Section 7.13 for a discussion of this idea.)

Alternative 7.12.3 CON

1. This option requires the design, creation and oversight of a new entity, the fulfillment house.

2. Some energy service providers would find their analysis capabilities more limited and their marketing much slower than what they might accomplish without the fulfillment house as an intermediary. For example, because they would have information only about customers who responded favorably to their literature, they would find it hard to develop useful databases of electricity consumers, or to cross reference these customers to other data sources or to data they had developed from other services they offer.

7.13 Considerations for the Mature Market

ALTERNATIVE: The CPUC should sanction a stakeholder working group to develop a practical model for a cooperatively owned and operated information clearing house.

A main theme of this entire report is that information flows of various kinds are essential to the success of a competitive electric services marketplace. A theme of this chapter is that different parties have different needs for and concerns about information flows, not all of which are fully compatible. One way to balance the needs of all parties is to create an information clearing house

that is designed, owned and operated by all of them. The clearing house would be a not-for-profit company owned by those participants in the California market who intend to rely on its services. Its board of directors would be structured to contain a fair balance of all stakeholder groups, including the ISO, the PX, UDCs, schedule coordinators, consumer organizations, competitive providers, etc. Its operations and management would be structured to perform the information flows required for system operations and for healthy competition, while protecting the privacy and other rights of customers.

The clearing house would not perform metering activities. It would acquire metered usage data, via the UDCs or other metering entities, from all customer premises and other points as needed for system operations and settlements. It would dispatch this data to the appropriate parties in a timely fashion. It would maintain a data base of all metered data, for which it would perform a custodian function. That is, it would disseminate the data to eligible parties on agreed terms and conditions, it would implement safeguards to prevent unauthorized access to data and it would provide a process to investigate and resolve any complaints. Under cooperative direction, it would modify its activities to adapt to the changing needs of parties as the market evolves.

Alternative 7.13 PRO

1. The needs and concerns of all stakeholders are built into the design, creation and operation of the clearing house.

2. Achieves the economies of scale and scope of a monopoly, but without requiring regulatory oversight or government management.

3. Cooperative control would enable the clearing house to adapt to changing market arrangements and conditions.

4. Many of the relevant parties already understand information issues quite well by virtue of their participation in the DAWG and other working groups, and could therefore participate in creating the new entity with small start-up costs.

5. Successful models already exist, such as the VISA bank card system. VISA is a not-for-profit company owned and operated by its member banks, i.e., banks that issue VISA cards. It serves primarily as an information clearing house, allowing its members to compete in whatever entrepreneurial ways they choose while providing a necessary common resource that is managed cooperatively for the benefit of all. Member banks have immediate access to information on their own clients, but have access only to statistical (aggregate, non-personal) information on the other banks and their clients.

Alternative 7.13 CON

1. Requires creating a new entity that has some features of a monopoly.

2. Requires creating a cooperative governance structure for the new entity.

3. Similar entities already exist. If this is deemed to be a major need, it should be determined whether existing entities can be used.

4. It is not clear whether the benefits generated by this new entity will justify the costs of creating it. Regulators should not fund such an effort. If it has value, then electricity retailers and other participants in the market should be willing to provide the required resources.

Chapter 8. Metering and Data Communication Systems

8.1. Direct Access Suggests Great Changes for Electric Metering and Data Communications

8.1.1. Introduction to Data Communications Systems

The Metering and Communications Team of the Direct Access Working Group focused on the technical and economic issues of metering and data communications related to Direct Access. Four main themes tended to emerge from the team's efforts:

- Data Communication is essential to the success of a competitive Electric Service marketplace.
- Needs, and the concerns that accompany those needs, for Data Communications differ among various parties; these differing needs may not be fully compatible.
- Technology that can accommodate the communication of hourly usage data for all of California's electricity customers exists, but cannot be installed for all customers by January 1, 1998.
- Implementing a Data Communications system –economically—is highly dependent on at least two factors: (1) the chosen scope, with a wide or comprehensive deployment resulting in lower costs per customer than a limited or narrow deployment; and (2) the realized operating savings, relative to current UDC costs. As the cost savings tend to increase with wider deployment, they progressively offset the higher costs of a wider deployment.

This Chapter begins by addressing the scope of changes anticipated for usage measurement in a Direct Access environment. An overview of the state of the metering and data communications industry today, as well as the information requirements for the future, leads into the discussion of feasibility and cost for implementing real-time metering in support of Direct Access. Finally, the issues of control, both over the activities and the technology (as standards) are reviewed.

8.1.2. Scope of Metering and Data Communications Changes for Direct Access

Under the Commission Decision D.95-12-063, restructuring of the present electric utility environment may result in a completely new set of information requirements that cannot be efficiently addressed using traditional methods. The competitive retail generation market may increase the energy usage measurement requirements for billing exponentially, as more and more customers elect direct and require real-time meters capable of collecting an energy measurement every hour instead of every month. Consumers may also need access to real-time pricing signals

in order to take full advantage of their hourly rates by modifying their electricity usage behavior. Generators may have their system inputs metered for daily settlement. After an orderly phase-in all consumers may also have the opportunity to select Direct Access. A communication system to enable daily settlement with the ISO may also be required

8.1.3. Existing Restructuring Decisions Constrain Flexibility

Existing CPUC restructuring decisions provide the context in which this assessment has been conducted. It is unclear whether the direction in D.95-12-063 and D.96-03-022 represents firm CPUC decisions, or was intended to provide interim guidance that this working group process should consider, but suggest modifications if appropriate.

D.95-12-063 addresses metering in three specific ways. It does not directly address associated data communication systems, so it is unclear whether references to metering implicitly also refer to data communication systems. First, metering may be provided by non-utility entities once metering standards have been adopted. Through subsequent rulings, development of proposed metering standards has been assigned to DAWG. Second, RTP/TOU meters are to be installed by the UDC for all customers except residential and small commercial on a specified schedule extending through 2001. Third, any customer wishing to receive virtual direct access may have the UDC install an "RTP meter" at the customer's expense. This decision clearly imagines an ongoing role for the UDC in metering.

D.96-03-022, on the other hand, explicitly directs parties (in what has become the Ratesetting Working Group) to investigate unbundling the proposed UDC and its exclusive distribution function activities into competitive and monopoly component services. This decision suggests that there might not necessarily be an ongoing role of the UDC in metering and data communications. The RWG is directed to file a report on August 26, and drafts clearly reveal that some parties propose alternatives that would eventually result in radical reductions of the scope of responsibilities of the UDC. In effect, the metering and data communications services are available.

The combination of these two CPUC decisions constrains IOU freedom or action with respect to metering and data communication systems. While IOUs have investigated advanced metering and data communication systems, and two have actually solicited bids through formal Request For Proposal processes, IOUs cannot feel they have the certainty that investment in such systems would be able to be recovered in rates in the traditional manner. Further, exclusion of the residential and small commercial customers from mandated RTP/TOU meter installation creates confusion concerning the proper systems to select, since these customers would derive the greatest benefits from universal systems.

Until the CPUC is able to resolve these ambiguities, IOUs are unlikely to make metering commitment systems commitments, which reduces the lead-time between the start of the installation process and the 1/1/98 start date for direct access. This reduces the number of customers for which such equipment will be available to accommodate direct access needs. Since the time

schedule of the meter standard development process is unclear, and it is further uncertain whether the CPUC can itself establish standards, this precludes non-utility entities from being able to install meters or metering and data communication systems for revenue purposes. Thus, many parties believe that the CPUC is itself on the critical path controlling metering and data communication systems capacity development by its necessity to make decisions.

8.1.4. Outlook for Direct Access Customers

Before technology assessment can occur, there must be a common understanding of the business conditions that technology is meant to address. In the case of Direct Access, this required discussion about 1) the type of information required and 2) the frequency with which the information must be delivered, broken down by size of load and stakeholder. This section describes the results of that analysis, which was used as the base set of working assumptions for the technology assessment presented in Section 8.8.

8.1.4.1. General Direct Access Data Prospects for of Industrial Customers

The Direct Access data requirements for industrial customers can be met today with the products that are available from various manufacturers of meters. These include products that have a phone modem interface and the ability to record and store energy and kilowatt demand data in five minute increments or less. From a metering and data communications technology perspective, Direct Access may have little effect on what is now standard practice for most industrial customers metering, except that a communication system must be added in most cases.

8.1.4.2. General Direct Access Data Prospects for Commercial Customers

The Direct Access data requirements for commercial customers can be met today with the products that are available from various manufacturers. These products have a phone or radio module interface and the ability to record and store energy and kilowatt demand data in five minute increments or less. While the technology capability exists, standard economic practice for most commercial meters does not include installing this level of technology sophistication except on very large commercial installations.

8.1.4.3. General Direct Access Data Prospects for Residential Customers

The Direct Access data requirements for residential customers can be met today with the products that are available from various manufacturers. New meters could be factory-ordered with a phone or radio module interface or existing meters could be retrofitted with an electronic module (usually done in a meter shop environment). Either approach produces a meter or

metering system that has the ability to record and store energy data in one hour increments as well as communicate that information to some other location. Manufacturers of meters and of automatic meter reading equipment are beginning to offer equipment of this nature in large quantities. Currently, some utilities are also implementing network meter reading on a large scale basis to provide consumption, time-of-use, demand, load profile and other metering on a monthly or daily basis. Installations typically begin in geographic areas where the cost of meter reading is higher than average or where population density is high. From there, they may proceed to other areas of a utility's service territory.

8.1.5. Clarification Of Concepts And Terms

Metering and data communications systems are the techniques and equipment used to achieve certain business functions within the Electric Services industry. Because a new paradigm is unfolding in this industry, many of the terms used repeatedly throughout this chapter and the rest of this report may not be well defined. At some point in the restructuring process, it may become important that we clarify how we view our subject matter and the words with which we may describe and discuss it. One such attempt to do just this may serve to indicate the breadth and depth of the concepts that may need to be reconsidered, and is presented in Appendix C.

8.1.5.1. Distinguishing Direct Access from Bilateral Contracts and Aggregation Arrangements

Enabling bilateral contracts may require hourly energy metering and daily meter reading for daily settlement, based on proposed ISO settlement requirements. Since the price of service has been contracted previous to purchase, outbound price signals to the customer may not be required. Inbound energy consumption signals for daily settlement are required for bilateral contract customers. If deemed acceptable, aggregation of customers with similar load profiles may still require sample metering to assure proper billing and daily settlement. Aggregated customers found operating outside the terms of the aggregation contract may have to be individually metered so that PX pricing and penalties could be applied.

While utilities typically require that their meters operate within +/-1%, and a few set their meters to operate within +/-0.5%, it is highly unlikely that any two customers may have "identical" load profiles that may fall within that range.

8.1.5.2. Virtual Direct Access

While Virtual Direct Access is not yet fully specified, such customers may be purchasing their energy from the PX at the spot market price. Virtual Direct Access customers may, therefore, require hourly energy metering and daily meter reading for daily settlement of hourly imbalances. Since bills are to be based on hourly usage, hourly meters are to be required. The volatility of spot markets requires outbound price signals to the customer so that the customer has the option

to change their load and energy use. Therefore, two-way communication capability would be required.

8.2. Direct Access Will Require Much More Information

8.2.1. Hourly Usage Data is Required to Support Electric Service Billing.

Customers who elect Direct Access, whether actual or virtual, will be billed by either their Electric Service Provider or the UDC for electric energy usage. This bill may be produced by the customer's Electric Service Provider (utility or non-utility) or that provider's agent. See Chapter 9 for details on the various options for billing.

8.2.1.1. Hourly Usage Data May be Actually Metered

The hourly energy consumption data used daily to settle with the ISO may be accumulated by the Electric Service Provider and used to prepare periodic customer bills.

8.2.1.2. Hourly Usage Data May Be Estimated from Average Usage Conformed to a Load Profile

If Direct Access customers are allowed to use an approved Load Profile instead of a real-time meter, they may be billed based on the metered consumption recorded and collected by the customer's UDC. In preparing the bill, the Electric Service Provider, the UDC, or some other party may allocate collected monthly usage data based on the authorized hourly profile. See Chapter 9 for further discussion of billing options.

8.2.2. Hourly Usage Data is Required to Support SC and ISO Functions

ISO settlements are based on hourly reconciliation of nominations, deliveries, and usage with Schedule Coordinators. Hourly settlements are an integral part of Direct Access (other than for potentially aggregable customers) and require that actual hourly information on energy consumption (or estimated information in the case of load profiling) is provided prior to final settlements.

It is unclear why the Schedule Coordinator and the ISO would require estimated information on load profiling instead of actual real time load profile data. A technology assessment should include all currently available alternatives, i.e., the fact that current technical solutions can provide actual real time load profile data.

8.2.2.1. ALTERNATIVE: Settlements May Be Finalized Daily

Some parties assert that final settlements of the hourly transactions must occur daily because of the magnitude of financial transactions. As an example, the UK Electricity Pool has used daily settlements since 1990 and plans to use daily settlements when 100 percent retail access becomes available in 1998; the stated reason is the tremendous dollar volume of daily trading and the cost of delaying settlement. Under this option, hourly data would have to be retrieved daily and the information uploaded to the ISO via Schedule Coordinators. This is the current proposal by the WEPEX team. Explicit PRO and CON arguments were not provided by any parties for this position.

8.2.2.2. ALTERNATIVE: Settlements May Be Estimated Daily, and Finalized Later

Other parties agree that hourly imbalances must occur, but disagree as to whether final settlements should occur weekly or monthly. Explicit PRO and CON arguments were not provided by any parties for this position.

8.2.3. Hourly Usage Data Is Required to Support Forecasts of Hourly Loads

Developing load forecasts for submission by Direct Access retailers to the ISO through a scheduling coordinator may require changes in current load forecasting and data collection practices. First, utilities and Direct Access providers may be required to submit hourly load forecasts for their customers. Second, the accuracy needed for these forecasts may be greater since the financial consequences of error are potentially more significant. These two major changes may lead to different needs for data and for new techniques in processing load data to support load forecasting.

8.2.3.1. Preparation of Short Run Load Forecasts

Utilities currently prepare a variety of forecasts as an element of planning for generation, transmission, and distribution responsibilities. The emergence of Direct Access may focus attention on (1) very short term load forecasts for unit commitment and dispatching, and (2) distribution system planning and optimization planning.

8.2.3.2. Preparation of Very Short Run Energy Forecasts

As the Direct Access market emerges, the potential financial consequences of ISO imbalance conditions may drive the market to develop greater competency in the forecasting of very short run load projections (day and hour ahead). This may require the availability of daily energy usage for the creation of dynamic load profiles.

In the restructured industry, all parties serving loads, regardless of market affiliation, must forecast 24-hour, day-ahead loads (equivalent to energy consumption) and provide these forecasts to a scheduling coordinator (SC or PX) which interfaces to the ISO.

Some aggregations of loads may be large enough and diverse enough that traditional methods of forecasting may be satisfactory. However, even these load forecasts may need to accommodate the fact that customers may move into or out of various aggregations (whether that of a specific DA retailer or the UDC). There may be numerous schedules provided to the ISO and the PX, each much smaller in scope than the former utility system load forecasts, and some composed of a single or a few end-use consumers. Therefore, the methods for preparing load forecasts for these much smaller groupings of loads cannot ignore the consumer-specific features of loads, e.g., things that cause a single or a few customers to do something at specific times.

All of the parties supplying load in the future may need greater access to accurate load profiles of their customers as an essential input into load forecasts. Interval metering data, retrieved quickly and used rapidly may be the key to successful load forecasting in this industry environment. No special data is required to support load forecasting, rather it is the quick acquisition and intelligent use of the same data needed for Direct Access billing transactions that may be most important. The amounts of load data required, and the determination of who is responsible to collect it and process it into load forecasts, does have implications for the UDC. It is expected that the UDC load forecasts may consist of total system load minus Direct Access load, and that settlements may also be based on this calculation. Therefore, the UDC may require the hourly load data from Direct Access customers for both forecasting and settlements.

8.2.4. Hourly Metered Data May Be Required to Support Distribution Charges

The UDC may require kilowatt-hour (kWh), kilowatt (kW), and kilovar (kVar) data from electric meters associated with customers who elect Direct Access in order to calculate the monthly distribution charge. It is expected that UDC distribution delivery rates may be based at minimum, on energy consumption measured in kWh. Some customer classes could also be charged based on peak energy demand, measured in kW, and peak reactive power demand, measured in kVar. Other charges, such as taxes, regulatory fees, etc., are also expected to be based on energy consumption. Virtual Direct Access may require hourly metering, although collection and delivery could be monthly. Depending on how settlements and daily load forecasting are done, the UDC may require hourly energy consumption in kWh for Direct Access customers on a daily basis. It is expected that the UDC load forecasts may consist of total system load minus Direct Access load and that settlements may also be based on this calculation. Therefore, the UDC may require the hourly load data from Direct Access customers for both forecasting and settlements.

8.2.5. Hourly Usage Data May Be Required to Support Customer Service

Metering and data communications systems supply critical data necessary for the operation of the customer service function of the utility. At a minimum the following data requirements would contribute to efficient operation of the customer service functions. It should be noted that the data described may not be available unless some form of automatic meter reading (AMR) system is in place.

8.2.5.1. Data to Support Outage Detection and Restoration

Utilities need real-time notification of outage conditions in order to dispatch crews and restore service to customers. Utilities also need outage restoration information and "power on" checks significantly improve customer service quality and efficiency.

8.2.5.2. Data to Support Turn Ons And Shut Offs

Utilities require opening and closing readings when customers move into or out of a premises. The reads are on-request. Utilities also prefer to monitor vacant residence for idle consumption.

8.2.5.3. Data to Support Power Quality Monitoring

Power quality data is desired by certain groups of customers to ensure that energy service quality is maintained for critical production operations. For example, voltage quality and harmonics control may be required for a factory's service.

8.2.5.4. Data to Increased Scope of Operations

Many believe that two-way communications are essential to create the benefits of increased scope of services and to leverage customer opportunities to participate in the competitive market. The distribution system operator, for example, may benefit from having customer-specific data and two-way communications with the Schedule Coordinator.

8.2.5.5. Data to Detect Meter Tampering and Theft Detection

Meter tampering and theft detection are operating costs incurred by all utilities, the monitoring and control of which would lead to more efficient operations.

8.2.6. Data to Support Efficient Distribution System Utilization

8.2.6.1. Data on Circuit and Transformer Loading

Monthly meter readings are used by the UDC to monitor and verify on-going load patterns for network planning and design, to optimize sizing and loading of circuits and transformers, and to ensure continued safe and reliable operation of the network. This optimizes the use of existing UDC facilities, reduces losses, and defers or eliminates the need for additional facilities.

8.2.6.2. Data on Interruptible Loads and Demand-Side Management

Real-time meter reads are used by the UDC on interruptible loads during curtailment periods to monitor and verify contract compliance.

Daily load profiles are used by the UDC to monitor demand-side management applications.

8.2.6.3. Data on Power Quality Monitoring

Where necessary or desired, meters could be installed to monitor power quality: spikes, surges, sags, drop-outs (zero voltage), over voltage, under voltage (brown outs), and harmonic distortion. When a power quality event occurs out-of-band, alarms could be triggered automatically to notify the customer and UDC. With that information, steps could be taken to mitigate the power quality problems.

8.2.7. Data to Support Customer Control of Usage

In order for the Direct Access customer to respond to price signals and to curtail usage, the customer must have a way of receiving ISO pricing signals. The customer should also be able to get current usage information for his own accounts.

Direct

Direct control of customer loads, through signals that are ISO initiated or supply aggregator initiated, require a communications system capable of interacting with the load control devices installed at the customer's premise.

Behavioral

In the absence of a load control device, customer's receiving price signals can elect to alter their behavior and, for example, turn down the air conditioning. Without a means for receiving the price signal, the benefits of real-time pricing are diminished. Customer behavioral responses to price signals need not be communicated directly to the ISO or to supply aggregators, however. The

customer may face different advantages from each medium that is used to provide price signals, such as the value of real-time information by direct signal from the ISO versus the use of less-sophisticated data communication channels.

8.3. Important Contextual Considerations in Evaluating Technology Options

8.3.1. Metering, Communications Industries are in Transition

The metering and data communication industries are currently undergoing transformation. Technology innovations of the last two decades are beginning to find applications in this market, resulting in the entry of advanced products and services that did not even exist a few short years ago. While this engenders great excitement and interest by consumers when offered free of charge, it is unclear how much they would actually be willing to pay for these advanced services.

8.3.2. Metering and Data Communications are Closely Related, Yet Distinct Operations

The common fusion of “metering” and “data communications” operations into a single “metering and communications system” concept is largely arbitrary. It can be seen as overemphasizing synergies, which, while they often do exist, may not be deterministic. Relying on comfortable “shop-floor” associations may also depreciate the present opportunity to re-examine fundamental relationships in light of restructuring.

8.3.2.1. Current State of the Metering and Data Communications Industries

From the inception of metering until the early 1980’s, meters were electromechanical in nature, with modern meters having a life somewhere in the range of 30 to 40 years. The resulting population of meters is, therefore, largely electromechanical and incapable of directly supplying the data requirements of Direct Access. Such meters can, however, be easily retrofitted with digital encoders and interfaced to the appropriate telemetry. As metering electronics has improved, fully solid-state, electronic meters were have been introduced. Typically, these meters have been only used for very complex metering installations such as interchange points and co-generation facilities (typical costs were several thousand dollars each).

8.3.3. Current State of the Metering And Data Communications Industry

8.3.3.1. Metering Equipment Presently in the Field

The electric meter population currently existing in the State of California consists of approximately 40,000 industrial and large commercial metering locations, 1.5 million commercial and agricultural metering locations, and 8.5 million residential metering locations. Of the industrial meters, approximately 50% are capable of supporting the data requirements for Direct Access (hourly recording of energy usage and daily meter reading) with only a portion, perhaps 20% to 50%, now outfitted to communicate, typically by phone line, back to a central data base. Of the Commercial meters, approximately 10% are capable of supporting the data requirements for Direct Access with fewer than 10% presently capable of communication to anything but a hand-held device carried by a meter reader. Residential meters typically may not now support the data requirements of Direct Access. There is a small, but growing, population of residential meters that have been outfitted with communication modules to allow for meter reading of kilowatt hour consumption data via a variety of communication means including drive-by van, telephone, and radio communications.

8.3.3.2. Metering Developments

From the inception of metering until the early 1980's, meters were electromechanical in nature, with modern meters having a life somewhere in the range of 30 to 40 years. The resulting population of meters is, therefore, largely electromechanical and incapable of supplying the data requirements of Direct Access. Hybrid meters, consisting of an electromechanical meter with an electronic register attached, were developed to meet more sophisticated metering requirements primarily due to TOU rates. As metering electronics improved, fully solid-state, electronic meters were introduced. Typically, these meters were only used for very complex metering installations such as interchange points and co-generation facilities (typical costs were several thousand dollars each).

During the 1990's all meter manufacturers began to mass produce hybrid electronic and solid state electric meters for industrial and commercial applications. The functional requirements for industrial and commercial meters helped to justify the added cost of these meters. The volume of hybrid electronic and solid state meter production compared to electromechanical is increasing and manufacturers are beginning to produce electronic residential meters with time-of-use capabilities for prices ranging between $75 and $125.

8.3.3.3. Communications Developments

There are essentially four forms of communication currently in use for electric meters: telephone, radio to a mobile vehicle or meter reader, radio networks and power line carrier. Each has economic and functional advantages in particular applications.

8.3.3.4. Telephone

Telephone based communications for meters has the apparent advantage of using a network that is currently in place in most locations. The difficulty, however, is that the telephone line is not necessarily co-located with the electric meter at the customer's location and a telephone connection has to be made to each meter. While built-in phone modem costs have declined in recent years, running the telephone line and the physical interconnection to the meter could be costly. In addition to initial and ongoing costs, jurisdictional disputes between the electric utility and the phone company as well as scheduling work, have combined to limit the application of telephone communication technology to large customers where the economics are justified or to locations where a radio network infrastructure can not be justified.

8.3.3.5. Radio to Mobile Vehicles or Meter Readers

To improve monthly meter reading efficiency, some utilities have elected to install radio modules in electric meters, both new and existing, and use radio equipped vehicles or meter readers with radio equipped hand-held computers to capture meter read data. While large numbers of these module-equipped meters (2.5 million electric and 4 million gas) are in operation today, the volume of data required for Direct Access constrains the use of these alternatives. These systems are typically not set up for hourly metering, which significantly increases the volume of data compared to monthly metering. Furthermore, given the proposed ISO settlement protocol requiring daily settlements, the basic technology may not permit compliance with ISO requirements.

8.3.3.6. Radio Networks

In the last few years, several manufacturers have begun to supply fixed radio networks and/or network based meter reading services that work with modules that are either adapted to existing meters or purchased in new meters. These radio networks consist of the module in the meter, a neighborhood collection unit with an integral radio that reads meters within its range and a wide area radio infrastructure that brings the meter readings back to a central location. These systems are characterized by very simple meter modules that are low in cost and relatively sophisticated neighborhood collection units that perform all kinds of functions allowing for load profile and real time pricing applications.

Fixed radio networks are most cost-effective when deployed in areas of medium to high density, as the cost per point goes up or down based on how many meters are within the range of the neighborhood collection unit.

8.3.3.7. Power Line Carrier

Power-Line Carrier (PLC) systems transmit signals over the UDC's electric distribution wires, and has typically been used only for remotely reading electric meters. The advantage for

communicating electric usage is that the network is already in place. The disadvantage (due to the very limited bandwidth imposed by needing to be compatible with the 60 Hz power lines) is that it is extremely slow. In truly remote areas, however, PLC remains a valuable alternative.

8.3.4. Multiple Technology Solutions May be Required

A review of the technology available for metering and data communications, the customer class requirements for different frequency of delivery and types of data, and the geographic location and likely dispersion of Direct Access customers leads one to the conclusion that combinations of different types of metering and data communications systems may need to be deployed to accommodate the requirements of Direct Access and customer choice

8.3.5. Communication Systems Used to Upload Metered Data May be Able to Serve Multiple Purposes

Once a communication technology is installed over a significant portion of a utilities distribution network, it could be used to change processes, reduce costs and provide additional services beyond meter reading. These functions would be of great interest if they could be achieved at a net benefit over any additional costs. Such operational benefits could then offset a portion of the original system costs. A summary of the potential benefits is presented below:

Meter reading costs could be reduced significantly if a meter reader no longer has to be sent to the meter site. The need to purchase and maintain manual reading equipment (handled devices) would also be reduced significantly.

Turn on and turn off costs could be reduced, since in most cases there is no need to physically turn the meter on or off, and remote meter reads may suffice.

Accident and injury costs associated with meter reading activities would be reduced.While evaluating technology options, it is important to note that a network can provide additional services at no additional cost if it has been installed with sufficient capacity to be expandable, scaleable, and is capable of being upwardly compatible. Otherwise, there may be significant costs associated with switching to a technology that can accommodate additional services.

Benefits from the implementation of interval metering and its related communications are expected from the increased scope of services that may be available and from the capability of power consumers to participate directly in providing services to the power system. The unbundled nature of ISO services, for example, allows consumers to offer the equivalent of spinning reserve, non-spinning reserve, and curtailability to the ISO. These are additional services that may add to the scope economies of communications between the consumer and the ISO. Generators and distribution companies may also gain the benefits of increased scope through such communications. With broader scope of services, scope economies may help expand the

penetration of communications and metering capabilities, eventually to virtually all electricity consumers.

Direct Benefits

Automated data collection results in higher customer confidence, fewer missed reads, and fewer inaccurate reads leading to a reduction in customer complaints and phone calls to the customer service call center.

Automated systems with “on-demand meter reading” capability enable operators to answer meter related questions without having to dispatch field personnel.

Meter investigations resulting from missed reads, inaccurate reads, unusual usage, or other reasons could be reduced.

Accounting expenses associated with special processing (e.g., meter re-reads, estimated bills) could be reduced.

Indirect Benefits

By shortening the meter read to collection time, accounts receivable associated interest expenses could be reduced.

Cash flow improvements include shortening the meter read to bill issuance time through automation of data delivery, which may benefit some utilities that do not currently use same day billing.

Indirect improvements of the bill issuance to collection time are possible by offering convenience services such as summary billing and selectable bill date. Flexible billing options may translate into improved payment performance since customers can choose bill receipt times that coincide with paycheck receipt and bill payment cycles.

Continuous monitoring of customer energy usage enables detection of usage on inactive accounts and improved ability to monitor customers with recurring payment problems.

Automation identifies sources and enables solutions to reduce line losses.

Other Benefits

Some systems provide the flexibility to provide different levels of metering service to any customer without installation of expensive meters. This includes Time-of-Use, Demand, and Real Time Pricing. Because these networks deliver this level of service through the network itself, the cost of purchasing expensive, stand-alone time-of-use meters is avoided.

With on-line checks, the utility can determine remotely whether a power problem is on the line or load side of the meter, thus avoiding the unnecessary dispatch of field personnel.

Some systems provide immediate alarms of meter tampering, obviating the need for seals used to prevent meter tampering.

By delivering positive real-time outage alarms and restoration notification for each meter, the distribution utility can rapidly identify the location and extent of the outage and better manage and monitor the power restoration process.

8.3.5.1. Natural Gas Meter Reading and Data Acquisition is Important for Combined Utilities

For any utility that distributes both electricity and natural gas, a metering and data communications system that is installed for Direct Access could potentially read the gas meters and the non-Direct Access meters as well. The same meter-to-telemetry issues prevalent with electrical meter reading would have to be addressed, and the issue of which entity is to own the meter and/or communication system may well come into play. Nevertheless, additional customers would make the per point cost of the metering and data communication technology less than it would otherwise be, and could make the enterprise economically justifiable for all customers.

8.3.5.2. Other Utility Uses for the Network

With additional investment for end-point devices, the capacity on a network can also be used for applications and functions like quality of service monitoring, automatic reconfiguration of the distribution system to reduce minutes of customer outage, other distribution automation functions, and home automation services.

8.3.5.3. Potential Cost-Sharing and Revenue Opportunities for Communications

There are potential up-side revenue opportunities for the owner or operator of a communication system that has been installed for Direct Access. Other meters could be read including water meters and gas meters that do not belong to the local electric company. Some of the communication alternatives available today can also be used to collect data from other sources such as vending data or security alarm data. These opportunities require additional investment in sensing devices, and would have to overcome the same issues of compatibility and security faced for electricity metering, but would utilize potential excess capacity in the network.

Communications networks may support a combination of metering and other services, including non-utility services. Thus, potentially, profits from the sale of such services could be used to offset partially he cost of implementing hourly metering services, if electric customers are paying for and bearing the risk of the communications network. Electric customers benefit to the extent they have access to the network without bearing the risk, i.e. the capital and technology risk components of the network cost is shifted to the unregulated subsidiary or a third party, and

such arrangements, if made appropriately, can ensure that there is no cost shifting from other parties to electricity customers.

8.3.5.4. Data Processing, Storage, And Transfer May Increase Under Direct Access

Implementation of Direct Access may require changes to the systems currently used to process customer meter reads and prepare customer bills. These changes may need to be phased in as needed to support the phase in of Direct Access.

The volume of meter data to be processed may increase with the implementation of direct and virtual Direct Access. Currently, the great majority of customers only have one meter read data item per month associated with their account, and that is the total energy consumption. Even most large accounts on TOU rate only have several meter reading data items per month associated with their account. A very small number of customer meters actually record interval data for billing purposes. With Direct Access, hourly energy consumption may be metered. The number of meter data items per meter per month may increase to 720. This increases the volume of data by 720 times for residential customers and about 100 times for a TOU customer. The magnitude of data volume increase may require increases in the capacity of billing and customer service computers to store and process the data, if Direct Access are deployed on a wide scale.

Also under current rates, most customers only have one energy price to be calculated per month. Even on TOU rates, there are only a few energy prices. A very small number of customers are subject to more than a few energy prices. With Direct Access, hourly pricing may be implemented. The number of potential prices to be processed per customer per month may increase to 720. This magnitude of data volume increase may require increases in the capacity of billing and customer service computers to store and process the data, if Direct Access is deployed on a wide scale.

For Direct Access, the meters may be read daily, the data processed, and the data sent to all parties associated with the transition. Current UDC systems are not set up to store or process daily data or transfer the data to other parties daily. These systems would have to be upgraded to provide this capability. The data transfers may have to be electronics since all parties may require the data on a timely basis. This electronic data transfer capability would also have to be developed or upgraded.

Unbundling of electric energy related services may also increase the information processing requirements. Since energy charges, distribution charges, and transmission charges may be calculated with totally separate pricing, the complexity of the billing process may be increased. The customers' bills may be more complicated since each of these charges may be a separate line item on the bill, compared to a single item on current bills.

Customers may be free to change energy suppliers at any time. This would increase the record keeping requirements for customer accounts to ensure that the correct parties receive the data and unauthorized parties do not receive the data.

In addition to system upgrades or development due to the increase in data volume, communication and data format protocols may have to be developed to facilitate the transfer of data among all involved parties in a timely, reliable, and accurate manner.

8.3.6. Distinguishing Among Ownership, Control, and Operation for Metering And Data Communication Systems

Ownership, Control, and Performance of Work are different dimensions connected to the provision of metering and data communication systems enabling Direct Access. This section reviews the differences between them, and identifies the major dimensions of concern for the policy decisions that the Commission must make in the coming months.

8.3.6.1. Ownership

Ownership is often understood as the ultimate claim upon the value of goods, and often manifests itself in the right to receive the profit in a property's use or the receipts from its sale. It often derives from purchase: the owner of a property is most often whoever paid for it. Ownership can also be the subject of negotiation, and title to a property, such as the physical components of a premises electric service, may be transferred to another in exchange for services of some value. Ownership usually implies the power to control the owned property, but such control is not necessarily absolute. Either law or common practice may establish or limit the manner in which an owner exercises appropriate control. Neither is ownership always exclusive, and no person with an interest is some property is usually allowed to act in a manner that is detrimental to those who may have other, albeit lesser, interests in the same property.

8.3.6.2. Control

Control is often understood as the ability to make decisions, enact policy and select alternatives for the function under discussion, including whatever facilities it entails. Control is often understood as a right and a responsibility of ownership, the presumption since the owner has the greatest interest and ability in the effect of the control exercised. Public policies may specify or limit control, where the public has an interest at stake.

The controlled activities here considered are the installation and maintenance of facilities and the routine production activities associated with metering and data communications. Complicated interests are involved between consumers and the various providers of services in an unbundled environment. It is important to note, however, that control over metering and data communications does not usually extend itself to equipment installed beyond the meter socket on

the customer's premise. Customer-owned premises equipment would still be subject to any appropriate regulation, presumably to ensure the security and stability of the overall system.

8.3.6.3. Operation

Operations are the specific activities over which control is exercised. In addition to rights and interests, one must also give further consideration to responsibilities. Many operations, especially those involving electric power, are dangerous to workers or the public if performed improperly. Still other operations, such as data communications, often determine financial results between parties, who therefore have an interest in such functions being performed properly. Operations are not always actually performed by the parties who are entitled to control those functions. Practical competence, legal or professional requirements, or risk considerations may influence the choice of whether to exercise control over operations directly or through an agent.

8.4. Options for Implementation Schedule

8.4.1. Installation of Meters and Communication Systems

The Commission decision adopted a five-year plan starting in 1998 and phased-in until 2002 for customers above 100 kW other than those within the Domestic, GS-1, and TC-1 customer groups to have real-time metering capable of hourly measurement. (A communication system to support the metering and reporting functions is also implied) Customers may be responsible for the cost of these meters.

8.4.2. Adopted Schedule

The Commission adopted, in Decision D.95-12-063, the schedule for real-time meter installation for those customers with maximum demands over 100 kW:

1/1/1998 500 kW and up

1/1/1999 400 kW and up

1/1/2000 300 kW and up

1/1/2001 200 kW and up

1/1/2002 100 kW and up

Interval recording meters are desired for Direct Access, but the communication system is unspecified and may change configuration during the phase-in to be economical. For example, initially the number of Direct Access customers may be small and their reporting requirements could be met by a relatively expensive telephone systems that are installed point by point. Two-way communication systems for universal deployment could then be installed in a progressive geographic manner during the phase-in period, if the need and desire for a universal metering system is determined. This may keep the final total installation cost lower than attempting to install a full two-way communication system in a piecemeal fashion.

8.4.2.1. ALTERNATIVE: Unscheduled Implementation

The Commission should recognize that the mandated phase-in of interval meters according to energy use determinants may not result in the lowest cost. The best way to optimize cost may be to install the meters in geographic blocks.

The marketplace, and not the UDC, should decide the methods for achieving meter installations to meet any proposed schedule of meter installations.

The Direct Access Working Group sought to explore alternatives to the specified phase-in schedule and its connection to metering requirements to achieve the phase-in determined. D.95-12-063, at page 79, also offers a meter installation schedule that is meant to compliment the Direct Access phase-in schedule. As this decision and other rulings invite modification to the phase-in schedule, accompanying impacts on any metering restrictions should also be expected. The communications system is unspecified and may change configuration during the phase-in to be economical.

If the Commission decides that kW are no longer the criterion for deciding who is eligible for Direct Access, and that all customers, regardless of class, should be allowed to be eligible in the

first year, phase-in of meter installations should be established in the marketplace between customers and providers.

No explicit PRO or CON arguments were provided by any parties for this position.

8.4.2.2. ALTERNATIVE: Resolving Concerns About the UDC Responsibility for Metering

Some parties believe that the UDC should not determine the exact method for achieving the Commission's mandatory schedule, even if the responsibility for achieving this goal rests with the UDC. A single, monolithic approach to metering or the communication system might severely dampen the markets for additional innovations that could add to the scope and scale benefits of new services that accompany Direct Access. An ongoing working group could monitor metering and data communications plans and schedules and insure that other metering and data communications vendors can integrate their technology.

No explicit PRO or CON arguments were provided by any parties for this position.

8.4.3. Direct Access to Include All Customer Classes

In their decision, the Commission also stated that the initial year of phase-in would include representation from all customer classes. This statement has been interpreted to mean that potentially large numbers of customers would require real-time metering capability in order to participate in the initial year. Eventually, all customers would be eligible for Direct Access, and would require the capability for hourly measurement if they so choose.

Some parties interpret this statement to mean that potentially large numbers of customers could require real-time metering capability. Others interpret this statement as an expression of Commission intent without particular reference to the means of achieving such representation. For instance, the use of load profiling could achieve widespread representation without requiring large numbers of customers to actually have real-time meters.

Two primary motivations expressed by the Commission for restructuring are: 1) to reduce costs to consumers, and 2) to increase consumer choice (Commission Draft Policy Decision, December 20, 1995, page 201). One mechanism to achieve these goals is to provide customers with a choice of suppliers; the more efficient suppliers are likely to offer lower prices based on their lower costs. A second mechanism is hourly metering. With hourly metering, customers may be able to select from various time-differentiated price plans. They may then be able to choose when and how to use electricity to minimize cost, maximize comfort, or achieve other desirable goals.

In the absence of a universal service principle, real time metering will be available only, or at least disproportionately, to large and urban customers. This difference results from the fundamental economics of metering. Large, urban customers have large power bills, which justifies their paying

more for metering. Also, hourly metering costs more in dispersed, rural areas than in compact, urban areas. When deployed in saturated installations, hourly metering is far more cost-effective than in scattered deployments, due to multiple economies of scale. Thus, many small customers will be able to obtain lower metering costs simply by fortuitously being located in or near groups of large customers who are desirable to power marketers.

8.4.3.1. ALTERNATIVE: To Provide Universal Real Time Metering

Unless the principle of universal service to hourly metering is applied in a restructured electric utility industry, many customers, especially small and rural customers, may be deprived of major opportunities for cost savings and choice that may be available to large and urban customers.

Alternative 8.4.3.1 PRO:

1. Universal hourly metering provides true customer choice, with all possible options available, including Direct Access, virtual Direct Access, and average pricing.

2. There are many potential operational benefits to universal metering systems, such as automatic meter reading, that can offset a portion of the costs.

3. With appropriate regulatory oversight over customer access to hourly metering, appropriate policy tradeoffs could be made between the fundamental physical and economic constraints of hourly metering and various public policy goals, including maximizing customer choice.

4. Universal metering provides enhanced system efficiency through the increase in generation capacity utilization that results from the effect of price signals on load shifting.

5. There are scale economies in implementation of hourly metering.

6. Unless the principle of universal service is applied to hourly metering in a restructured electric utility industry, many customers, especially small and rural customers, may be deprived of major opportunities for cost savings and choice that may be available to large and urban customers.

7. Universal hourly metering increases customer economic welfare through the free exercise of choice in time of consumption.

Alternative 8.4.3.1. CON

1. The cost of regulation must be weighed against the public policy benefits. Before the Commission mandates universal deployment of interval meters and imposes these costs on captive ratepayers they may want to first assess the actual costs and benefits.

2. Mandatory deployment of interval meters may limit technological innovation and customer defined customization.

3. The perpetuation of command and control regulation in a universal meter mandate runs contrary to the transition to a competitive generation market. It is time for the Commission, and the UDCs, to allow customers to exercise choice, including the type of meter to install if they wish to exercise competitive options.

4. Not all of the parties agree that new, more sophisticated meters are needed for all classes of customers to participate in Direct Access. Some parties believe that the cost of installing new meters for all small customers creates a barrier to entry that may dissuade power providers from serving those customer segments under Direct Access. These parties encourage the Commission to examine alternatives for small customer classes, including the use of load profiles to estimate load requirements. Customer meters may still be read on a monthly basis, and for most small users, this may be fine. Small customer or their power providers who find it in their interest to obtain a more sophisticated meter should do so as a matter of choice, not as a matter of mandate.

5. The cost of universal metering may be too large to pursue at this time.

6. Existing billing systems capabilities do not allow for processing of all of the information for universal metering.

7. Customers may not want to use hourly interval meters.

8.4.3.8. ALTERNATIVE: To Allow an Unfettered Market

The Commission should provide the most extensive choice of service providers and load profiling opportunities to all customers. This can be best achieved by specifying policy goals and high-level mechanisms, with specific implementation left to those with expertise in metering.

The Commission should consider how its policy approach to metering and data communications affects equity and choice for all customers in the context of an unfettered electric power market.

Some parties believe that an unfettered market (except for interface and safety standards) in metering service would usually be a desirable policy goal, resulting in the most socially optimal deployment of such services. Furthermore the ongoing and increasingly sophisticated (over-time) provision of load profiling options may help achieve market access for all customers and avoid market “failures."

The Commission should ensure that metering is not controlled by the metering industry itself or others with vested interests in the outcome of metering implementation. Rather, the Commission should examine meter implementation plans and schedules to ensure that monopoly results cannot occur. One way to do this is to require fuctional standards applicable to any venders of metering, communications, and related services. This may best be accomplished by developing specifications for an open architecture in metering and in data communication, which could be accomplished by the use of open standards for meters and the meter-telemetry interface.

While an unfettered market is usually a desirable policy goal, in metering services it can be expected to result in metering being offered to more customers, at lower cost, who are large or urban and fewer customers, at higher cost, who are small or rural. An unfettered market in metering services will likely result in an uneven availability of metering and, thus, may indicate an imperfect market for access for all customers to the range of choice intended by the Commission.

Alternative 8.4.3.2. PRO:

In metering, there are quantifiable economic savings associated with regulation. These include 1) enhanced system efficiency through the increase in generation capacity utilization that results from the effect of price signals on load shifting, 2) scale economies in implementation of hourly metering, and 3) increased customer economic welfare through the free exercise of choice in time of consumption

With proper Commission oversight and the use of open standards to ensure a metering-communications architecture with "plug-and-play" capabilities, potential monopoly results and potential barriers to entry of new technology could be reduced or eliminated.

Alternative 8.4.3.2. CON:

The costs to develop specifications for an open architecture are potentially high and the time to develop such specifications would potentially delay implementation of metering. The additional costs of vendors to conform with open or non-proprietary standards could increase the costs of metering to all who employ it.

8.5. Options for Ownership

Under the industry restructuring proposed by the Commission, the possibility is raised that parties other than the UDC could eventually be involved in the ownership of various elements of the metering and data communication systems that may be developed to replace the current equipment. Whether the customer, specialized operators of various items of equipment, or others may want to own this equipment is an economic question dependent in part on the results of the Ratesetting working group and in part on the likelihood that the parties making the investments, whether regulated by the Commission or not, need to see a high probability of recovering their investment and a reasonable rate of return on it.

In D.95-12-063, the Commission states that, “All customers may be individually responsible for the cost of the meter installation, and can opt to pay for it on their bill in reasonable installments that avoid severe bill impacts or hardships.” The decision further suggests that a customer may obtain a real time meter to advance his access to Virtual Direct Access.

The Commission decision can also be interpreted to mean that the UDC may be the default supplier and installer of meters for all customers, with the meter being supplied and installed at the customer’s expense.

Regardless of ownership, all metering and data communications equipment and installations may be required to comply with applicable standards in place today or developed in the future.

8.5.1. ALTERNATIVE: Customer Ownership

End-use customers should have the option to decide if they want to own their meters and control the meter data, or select a company to provide that service, or allow their UDC to provide all metering functions. Customers who are not satisfied with the value of services from their vendor should be allowed to shop the market for a competitive meter with the "value added" features desired or return to their UDC. The customer needs to rely on regulated safeguards to assure that meter manufacturer certification standards, data compatibility standards, and installation safety standards are established and enforced. No other restraints need occur. At this critical time, the Commission should not close the option for customers to own their meters or to control their electricity usage data. To assume that only the utility monopoly is capable of satisfying customer meter needs appears to be totally inconsistent with the fundamental principles of Direct Access.

If one assumes that the elemental connection to electric service is provided primarily, not to any residential or non-residential tenant of real property, but to the owner, the implications for a tenant to elect Direct Access are unclear. Tenants, of course, enjoy certain rights in billing if they are the customer of record and charged for the service they use. But owners exercise reasonable control over the nature of that electric service, even including the decision whether they or their tenants are to be the electric service customer. Property rights at a premise tend to determine control over goods and services appurtenant to the premises, regardless of whether those appurtenant facilities are owned or not.

Alternative 8.5.1. PRO:

1. The customer's right to select, own and control meters and meter information is fundamental to Direct Access.

2. Improvements in meter technology may advance at a greater pace and to higher levels if the meter industry must respond to millions of customers rather than a few UDC's.

3. The customer who is responsible for paying for the meter owns it. This tracks what happens in telecommunications, where customers who find it economic to do so purchase their own switches.

4. The customer's ability to obtain the benefits of a broader scope of services or to choose a narrow scope of services is bound together with the customer's ability to choose and own specific metering and data communications technology, and should not be limited.

Alternative 8.5.1. CON:

1. Decisions in the market are often made for other than economic reasons and it is not up to outsiders to determine whether the decisions are good or bad.

2. UDC's are in the best position to provide large volume of metering equipment and can bargain for superior price and value. (However, this buying power could be used to provide lower cost meters to customers, allowing for both customer ownership and profit potential for the UDC as a reseller of meters.).

3. If ownership is a requirement, some customers may never take advantage of Direct Access

4. Because the meter is a component of the UDC's distribution system, the acts of one private party could result in substantial injury, damage or inconvenience to his neighbor

5. The existence of energy theft suggests that it may be inappropriate to allow customers free rein in the metering arena.

6. If Customer is defined as the premise owner and therefore the only acceptable meter owner, then tenants may be included or excluded from participation in Direct Access against their wishes.

7. Real-time measurement capability, not meter ownership, is the only fundamental requirement for Direct Access participation.

8. Ownership may be incorrectly interpreted to mean unrestricted control of the meter.

9. Some metering infrastructure costs cannot be clearly allocated to individual customers.

10. No advantage to those unable to purchase their own meters.

8.5.2. ALTERNATIVE: UDC Ownership

Discussions of non-UDC ownership inevitably focus on the meter, which historically has been the connection for usage measurement. The utility has traditionally carried a substantial investment in the meters installed in the field and those carried in the associated meter shop inventory in authorized rate base. The ongoing costs of personnel and other expenses were recovered as costs as an element of necessary revenue requirements. In a few instances the utility has contracted out metering and data collection. This may result in a shift of the mix of investment and expenses toward expenses, but only in situations where the utility elects to divest itself of all meters. In the restructured environment, the utility may retain its role as the meter owner and supplier for all non-Direct Access customers.

For Direct Access customers, the UDC recognizes that customers electing Direct Access (physical or virtual) may be responsible for bearing the cost of the meter, which, in theory, they can do through the UDC or via their own sources. The UDC, as it does today, may continue to stock a variety of meters to meet customer specific needs, but is fundamentally less interested in

who owns the meter than it is interested in maintaining control of the end-point of its distribution system (which is the meter).

Evaluation of the technical alternatives in Section 8.8 indicate that there are a number of options that could provide other service benefits to all distribution customers, regardless of their Direct Access preference, using the infrastructure installed. To the extent that UDC ownership of the communications system(s) would result in improved non-discriminatory distribution service, the UDC should retain ownership and/or control of those systems.

Some parties believe that the UDC=s have an objective of retaining ownership and control of the metering, communications, and billing function. And furthermore that the UDC=s seek Commission approval through Commission Decisions on Direct Access and also Rate Unbundling of a multi-year expenditure of hundreds of millions of dollars to deploy an Automated Meter Reading system, with a reasonable Utility expectation of recovery of this investment.

Alternative 8.5.2. PRO:

1. Scale economies available to the UDC may result in comparatively lower costs for all customers who elect Direct Access.

2. As a regulated entity, the UDC can provide non-discriminatory metering and data communications services to retailers, thereby encouraging retail competition in energy supply and services.

3. All customers receive the benefit of the communications system

Alternative 8.5.2. CON:

1. If UDC's are allowed to continue to own meters and to control the meter data, the results of that decision may stifle competition unless regulations are implemented for the communication of the information.

2. The UDC is not currently perceived as retailer-neutral.

3. If UDCs are allowed to control deployment of real-time meters because this results in other cost or revenue benefits then the cost to the customer should be offset by the value of the benefits.

4. It should not be assumed that the UDC is the only entity that is capable of providing the lowest meter cost for all customers. An "open market" may prove otherwise.

5. The UDC has strong incentives to limit the scope of customer services, particularly customer services that enable it to respond to prices, obtain curtailment capabilities, and provide the customer with the ability to provide ancillary services.

8.5.3. ALTERNATIVE: Provider Ownership

Energy Service Providers should have the right to own the metering and data systems that they employ to serve their customers. At the point at which the system consists of central equipment and the inter-customer network of communications, it is imperative that the competitive, private marketer of Electric Service should be able to exercise substantial control over those systems employed to meter, communicate with, and bill its customers. Their systems should however, be flexible enough to equally accommodate customers who wish to provide their own premises equipment as well as those who wish their ESP to provide equipment for them.

Alternative 8.5.3. PRO:

1. Customer segments desired by a retailer may be more likely to receive attractive inducements to sign up (including metering).
2. The provider can retain control of his own information
3. The entity who is responsible for paying the meter owns it
4. Ownership may be incorrectly interpreted to mean unrestricted control of the meter
5. The provider should be given the opportunity to own the meter and/or the communication system in order to provide the best possible bundle of services to each customer group, assuming that it avoids monopoly practices.
6. The Provider can retain control of access to the data it needs for business management.

Alternative 8.5.3. CON:

1. Reliability and safety of the distribution system may suffer
2. The cost of the meter and communication system is unlikely to be a barrier to competitive market access.
3. Non-desirable segments may never be offered competitive access.
4. Provider control of information is likely to raise barriers to consumer choice and stifle competition.
5. Would require creation of a separate institution to monitor and police metering.

8.6. Options for Operational Control

Regardless of the Commission's decisions on ownership and control, the question of who may actually perform metering and data communications activities must be addressed. This section

breaks metering and data communications activities into three basic categories: 1) Installation Operations, 2) Production Operations, and 3) Maintenance Operations. The sections below define each of these categories.

Due to the inherent safety concerns associated with metering and the connection to the energized distribution system, only "qualified" employees should install, remove, turn on, turn off, or test metering equipment. Qualifications may include, among other things, proper training and education concerning electrical hazard, safety requirements, metering, agreement to comply with established standards, and acceptance of responsibility and liability. The question seems to be: In which enterprise should these persons be employed.

8.6.1. Installation Operations

In D.95-12-063 (as modified by D.96-01-009), at pages 79-80, the Commission states:

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

- Our primary concern, is that our oversight of the utility includes the assurance that these services meet specific service, safety, and reliability standards. Therefore, we are requiring the investor owned utilities to install the new RTP or TOU meters

- Pending the adoption of performance specifications and standards which assure the functional quality of such devices, the utility will continue to provide metering service for all utility service customers

Clearly, the Commission indicates that the UDC may continue to have a responsible role in the matter of metering, yet leaves open just what that role might be. The meter installation schedule was established to compliment the Direct Access phase-in schedule discussed at page 69 of the same decision, which also invites parties to offer alternate schedules and parameters for the phase-in of Direct Access. Furthermore, the Joint Assigned Commissioners' Ruling dated May 17, 1996, at page 11, directed that: "The working group should not assume that Direct Access requires special metering and communications systems."

The installation activity normally requires working with a "hot socket" and may require special training to perform without risk of injury. In cases of simple residential and small commercial services (120/240 volts, single phase), the installation of a meter may involve no more risk than the installation of a new panel fuse circuit breaker which, while hardly risk-free, is still accomplished by contractors, handymen, homeowners, and tenants in what must be thousands of times each month in this state. In cases of more complex service (poly phase), however, some UDCs have modified their internal policies to restrict installation and maintenance of these

services to meter shop personnel who have higher qualifications and are professionally trained to work with complex metering systems safely.

There are basically two alternatives for who should install RTP and TOU meters. The Commission can continue to allow the UDC exclusively to perform this work, or it can authorize the installation of these meters by appropriate third parties.

8.6.1.1. ALTERNATIVE: The UDC Should Perform Installation

The UDC should retain this responsibility. There are safety reasons for doing so. The electric meter socket is essentially a live switch, that if handled improperly, is life threatening. While local government authorities currently have and are expected to retain accountability for the inspection of customer wiring, this activity occurs prior to the installation of the meter. If the wrong meter is installed, or the meter is installed improperly, hazardous conditions are created which can cause harm to anyone who deliberately or inadvertently accesses the meter or the panel, including utility personnel.

These employees also ensure that the entire metering system (meter, CTs, PTs) is accurately operating as one unit once the installation is complete, as errors affecting accuracy have greater potential for revenue impact at these installations.

Alternative 8.6.1.1. PRO:

1. The UDC has the expertise and equipment in place to perform these activities.
2. Meter installation must remain a UDC responsibility because improper installation may negatively impact the overall distribution system.
3. Ability to bring adequate resources to bear to meet Commission schedule.
4. UDCs more likely to be able to take advantage of scale economies to reduce costs as installer for all retailers.
5. UDCs are the most knowledgeable about customer base and geographic territory.
6. Sufficient metering standards exist and no additional standards need to be developed.

Alternative 8.6.1.1. CON:

1. The installation of a metering or communications system could be specified along any appropriate performance standard.
2. Calibration is not a meaningful issue. Meters, CTs, and PTs are calibrated, and maintain their calibration, independently of one another.

3. Stifles competition in meter installation, and competition could result in lower costs.

4. Customers, who are responsible for the cost of metering, would have no control over the work.

8.6.1.2. ALTERNATIVE: Any Qualified Party Should Be Allowed to Perform Installation

As long as safety, reliability and accuracy standards are met, no qualified party should be excluded from installation activities, nor should any customer not select their own installer.

Alternative 8.6.1.2. PRO:

1. Promotes competition and would tend to lower costs to the customer.

2. Facilitates customer choice; customer control is consistent with having customers directly responsible for costs.

3. Within specified standards and connection requirements of the UDC, the customer and the energy supplier can employ customized installation procedures and meter applications tailored to the customer's needs.

4. Redistribution of possibly underutilized UDC meter installation assets among multiple non-utility meter installation firms would increase economic efficiency.

5. It is perfectly feasible for meter installation to be handled by specialized, licensed personnel. (The English/Wales deregulated electricity industry now allows licensed meter operators to install and maintain meters. A separate organization is under contract to the POOL to read these meters on a daily basis and provide the data to both the POOL for settlement and to the Tier II energy suppliers for their use in billing their individual customers for energy usage.)

6. The installation of a metering or communications system could be specified along any appropriate performance standard.

7. Allows bundling of energy related services by retailers.

Alternative 8.6.1.2. CON:

1. Standards for accuracy, safety, and certification for Direct Access revenue meters and qualifications for meter installers have yet to be developed by the UDCs or accepted by the Commission. Development of these standards may result in additional costs.

2. There is an existing utility investment in meter inventories, equipment for meter installation, and facilities for testing and repair of meters. If these assets become stranded, they may increase consumers costs through CTC.

3. Creates unresolved concerns over the control of connection and disconnection.

4. Creates unresolved concerns over the ongoing accuracy of meters.

5. Scale economies available to UDC may not be available if multiple companies enter the business, tending to increase installation costs

6. Since meter installation is an infrequent event, the opportunity for consumer fraud increases.

7. A separate entity must be created to ensure accuracy.

8.6.2. Production Operations

Operation of a communications system would entail collection, validation and delivery of usage measurement and, possibly, other data, and providing outage reporting services. Metering includes a very limited set of services that are closely linked to the distribution system: providing physical connection and disconnection to and from the distribution system.

UDC distribution system operation responsibility may require that the UDC exercise control over connection and disconnection of meters, as in turn-ons and turn-offs.

Measurement Services

Operation of a metering system for usage measurement has traditionally been dominated by the meter aspects of the business. The sophistication of the meter was a function of the detail and complexity of the required measurement. The meter reading function served to transport the measurements from the meter to the billing center. The most common approach has been to send a human meter reader to the service location equipped with a hand-held computer. Collected measurements were later entered into computer data systems for bill processing and archiving. The efficiency of conventional meter reading is dependent on 1) all meters in a geographic area to be scheduled for reading at the same time, 2) designing a path from meter to meter that minimizes travel time between meters and 3) spending as little time as possible actually downloading or entering measurements from each meter.

Essential Customer Services

The introduction of a competitive retail market should benefit consumers financially, while not resulting in undue confusion or decreased safety. There are a number of issues directly affecting consumers of electric service, regardless of provider.

Consumers moving to new residences still need to have someone turn on their electricity. In a competitive market, as today, they may know who to call, as the UDC remains the default provider of last resort.

Consumers may also require disconnection, whether at their own request, or due to failure to meet payment agreements. Consumers need to know what personnel are allowed to perform this disconnection and, where disconnection is the result of switching among suppliers, should be able to transition without ever losing power.

When the lights go out, or live wires are lying in the street, the consumer needs to know who to call. These situations transcend issues of retail energy supply, they are public safety issues. However, none of these concerns may materialize so long as the UDC maintains a commercial presence with the customer.

Access to Usage Measurement

A flexible means to deliver data to all interested parties is an essential requirement of the metering and data communications systems operators. All authorized parties must be able to access the information they are entitled to , and no more.

8.6.2.1. ALTERNATIVE: UDC Should Operate Metering and data communications Systems

The UDC is the logical choice to operate the metering and data communications system. It can serve both providers and consumers as a neutral, regulated provider of cost-effective measurement services.

Alternative 8.6.2.1. PRO:

1. Scale economies available to the UDC may result in comparatively lower costs for all customers who elect Direct Access.

2. As a regulated entity, the UDC can provide non-discriminatory metering and data communications services to retailers, thereby encouraging retail competition in energy supply and services.

3. All customers receive the benefit of the communications system

4. Customers may not suffer redundant costs for basic metering services when performed by multiple companies operating in the same territory.

5. UDC operation does not preclude an ESP from offering advanced energy services, or from choosing to act as the customer's agent in its dealings with the UDC.

6. All required metering standards are in place.

7. UDC delivers and distribution system operations responsibility requires control of connection and disconnection of meter, turn-on and turn-off.

Alternative 8.6.2.1. CON:

1. If UDC's are allowed to continue to operate metering, the results may stifle competition unless regulations are implemented to communicate the information.

2. The UDC is not currently perceived as retailer-neutral.

3. It is feasible for a separate organization to read these meters and to provide the data to others for their commercial purposes.

4. The operation of a metering or communications system could be specified along any appropriate performance standard.

5. Third party metering for Direct Access need not displace existing UDC metering. However, eliminating UDC control of customer information is crucial to stimulating a viable competitive market.

8.6.2.2. ALTERNATIVE: Any Qualified Party Should Be Allowed to Operate The Metering and data communication System

The UDC has natural conflicts with the expansion of service options and the further development of customer capabilities, which suggests that other private or public entities may better operate the metering and data communications system:

As restructuring proceeds, the Commission may elect to open currently regulated aspects of the metering and data communications business to competition. Those firms whose facilities are used to transmit electricity or who bill for energy transmitted and energy consumed all have a stake in insuring that metering and data communication systems are operated correctly and safely and that meter reads are accurate. In addition, these stake holders may need to have the flexibility to install their information systems to obtain energy information that is directly or not directly used for revenue purposes. The UDC has natural conflicts with the expansion of service options and the further development of customer capabilities. This suggests that subject to certain limitations, such as the qualifications of a firm, other private or public entities may better operate the metering and data communications system:

Alternative 8.6.2.2. PRO:

1. Competitive metering may result in lower costs.

2. Natural and consistent incentives exist to meet the diverse and changing needs for services of customers and others related to customer data and communications.

3. Fewer unintended consequences are expected if the UDC is not involved in operation of the metering and data communications system.

4. As long as the entity is not affiliated with any other aspect of the energy business, they offer neutrality.

5. It is feasible for a separate organization to read these meters and to provide the data to others for their commercial purposes.

6. The operation of a metering or communications system could be specified along any appropriate performance standard.

7. Promotes competition.

8. Facilitates customer choice.

9. Allows unbundling of energy related services by retailers.

Alternative 8.6.2.2. CON:

1. Less direct regulatory oversight may be available if there were problems with the operation of metering and data communications.

2. Scale economies may not be available; no assurance of non-discriminatory service.

3. Standards may need to be developed.

4. May increase UDC average costs.

5. Creates safety concerns with control of connection and disconnection of meters, turn on and turn off

6. Scale economies available to the UDC may not be available if multiple companies enter the business.

7. Requires development of a new regulatory body to ensure safety, accuracy, reliability, and security of the UDC distribution system and of customer's usage measurement information.

8. Only Direct Access customers receive the benefit of the communications system.

9. Customers may suffer redundant costs for basic metering services when performed by multiple companies operating in the same territory.

10. As long as the entity is not affiliated with any other aspect of the energy business, they offer neutrality

8.6.3. Maintenance Operations

Maintenance typically consists of activities associated with the asset base, including certification, quality assurance, field accuracy testing, field safety testing, removal, repair and return of defective equipment to the manufacturer.

There are basically two alternatives for who should perform this work, either the utility or another party elected by the controller of the metering and data communications systems.

8.6.3.1. ALTERNATIVE: The UDC Should Continue To Maintain Metering and data communications Systems

The UDC may be responsible for maintaining all metering. As mentioned above, the meter is the end point of the UDC's distribution system. It is essential that all customers connected to this system receive consistent, safe and reliable service. In order to ensure this high quality service, the distribution system must be properly maintained. The Commission recognized this in their December 20, 1995, decision when they state " In the restructured industry, they (utilities) would continue their obligation to provide non-discriminatory distribution services to all customers, including Direct Access customers in their service territories." UDC PBR mechanisms would be structured to focus on utility performance in this critical category, ensuring that the utilities continue to provide quality distribution services and do not jeopardize distribution service reliability or safety. Recent observations of restructuring in the UK suggest that even when metering activities are open to competition, 95% of the customers chose the Regional Electric Company (their UDC) to perform these activities.

Non-discriminatory maintenance services ensure that meters are reporting the information accurately. Given the number of parties with a vested interest in usage information (whether for forecasting, reconciliation or billing) the impact of improper calibration, improper installation, incorrect record keeping (ex. Meter multiplier), or missing information is multiplied. The impact of downstream correction once the errors are identified and corrected adds additional complexity. Furthermore, the impacts of inaccuracies are felt not only by the customer with the problem, but by all customers, as these errors impact forecasting and reconciliation. This is remarkably different from in the past, where meter accuracy concerns have generally been associated with addressing customer high bill complaints or investigating theft detection as a result of tampering with the meter or its settings.

Alternative 8.6.3.1. PRO:

1. The UDC has the expertise and equipment to perform these activities

2. Maintenance services are part of the overall distribution system and should benefit all customers, not just those electing Direct Access

3. UDC maintenance ensures safety, accuracy and reliability

4. All required metering standards are in place.

5. The UDC has greater incentive to maintain meters properly as many of its own charges are dependent on accurate measurements.

Alternative 8.6.3.1. CON:

1. It is perfectly feasible for meter maintenance to be handled by specialized, licensed personnel.

2. The maintenance of a metering or communications system could be specified along any appropriate performance standard.

8.6.3.2. ALTERNATIVE: Any Qualified Party Should Be Able to Maintain Systems

Under restructuring, the maintenance requirements for metering and data communications would remain very much the same as they are today. However, restructuring presents an opportunity for companies to bid the service competitively. The Commission may need to determine how best to track performance and qualifications of firms who enter this business.

Alternative 8.6.3.2. PRO:

1. It is feasible for a separate organization to maintain metering and data communications systems such that reliability, safety and accuracy are not reduced

2. Maintenance standards for metering or communications system could be specified along any appropriate performance standard and , in many cases, have already been developed.

3. Promotes competition

4. Facilitates customer choice

5. Allows bundling of energy related services by retailers.'

Alternative 8.6.3.2. CON:

1. Significant additional overhead may be required to monitor multiple organizations involved in meter maintenance activities

2. No assurance of non-discriminatory service

3. Standards may need to be developed

4. Creates concerns with control of connections and disconnection

5. Creates concerns over ongoing accuracy of meters

6. Creates concerns over safety and reliability

7. Scale economies available to the UDC may not be available if multiple companies enter the business

8. Requires creation of separate agency to monitor compliance

9. Most likely to result in distribution system (and reliability) problems due to inexperience, lack of familiarity with a wide variety of meters, and lack of familiarity with the distribution system

10. Increased opportunity for tampering and theft if customer has control over unregulated maintenance firm.

8.7. Options for Structural Alternatives

Historically utilities have controlled the metering function, including retrieval of data from the meter and the ultimate processing of the data to render a bill for the customer. In the great majority of cases the utility has also owned and operated all equipment used in these related activities. In a few instances the utility has contracted out one or more of these activities, but has continued to exercise control over them. Section 8.3.6 will review the distinctions among ownership, control and performance of the work. Section 8.7 will review structural alternatives for metering and data communication systems activities.

For example, CellNet Data Systems, Inc. has a 20 year contract with Kansas City Power & Light to obtain metered consumption data and deliver such usage data to the utility in an agreed upon computer data format. The utility retains overall control of the metering function, even though its employees do not perform the work.

Commission D.95-12-063 indicates that all of these component services would remain the exclusive role of the UDC, unless and until the Commission decides otherwise in the unbundling/rate design aspects of restructuring.

The Commission sanctioned examination of further unbundling of the UDC distribution function in D.96-03-022, but the efforts of utilities and a recently formed working group are not likely to lead to further Commission unbundling decisions in the near term. Commission decisions and assigned Commissioner rulings [ACR] have not yet established a schedule for resolving this major issue. The Ratesetting Working Group is required by an ACR [Duque, June 21, 1996] to provide its recommended schedule to the Assigned Commissioner on August 26, 1996.

This section addresses important policy questions that the Commission must resolve expeditiously, including questions about the role of the UDC versus other potential providers of metering and data communication system services. While these unbundling/rates issues appear to have been formally assigned to the Ratesetting Working Group, their impact on the

implementation of Direct Access require that they be addressed in this report. This is a specific example of the general phenomenon of substantial interdependency among the various working groups' assigned topics, discussed with the Commission at scoping workshops and checkpoint meetings. There is need for the Commission to have a decision-making process that weaves together input from various forums in its next level of more detailed restructuring decisions. Further, some of the options discussed in Section 8.7 can not be implemented immediately; thus, this discussion should be understood in the context of a multi-year time frame. It is anticipated that the UDC may continue to play a transition role even in those options where ultimately the UDC is no longer the exclusive provider of these services.

The activities discussed in Section 8.3.6 attempted to address particular aspects of metering and data communications on a standalone basis. What is less obvious, but more important, is determining whether these systems may be treated independently or not, and if not, then what party may exercise control over the complete set of metering and data communications system activities.

The control perspective is one crucial element of the decisions that must be made to ensure that these services are available by 1/1/98 and beyond. In the various assigned Commissioner rulings guiding this working group and the ratesetting working group, the Commission may be open to revising its determination that these activities must be retained by the UDC, but the explicit process that might be followed for this decision to be made is unclear. To facilitate an informed debate about these control decisions, this subsection identifies and discusses several different organizational structures that would control the metering and data communications systems necessary for Direct Access and future unbundling.

The operation, maintenance and installation of metering, communication systems and consumption history database services for electricity consumers are essential services required for the commercial operation of specific Direct Access transactions, for a broader Direct Access market that includes aggregators, and for the regulated monopoly distribution functions. While at least five different organizational models have been identified that could be used to control these services, they fall into two major categories, regulated models and competitive models. The distinguishing feature of the two alternatives is control over these functions. Within each one there are a variety of options described which could be further augmented by various options for contracting specialized services. The third alternative is a hybrid of the regulated and unregulated models.

The following sections describe the three alternatives and their options:

1) Regulated Alternatives, either A) the electric UDC, B) a monopoly information services provider, or C) a hybrid alternative, a stakeholder-owned, monopoly information clearing house; or

2) Competitive Alternatives, either: A) the energy service providers, or B) competitive, standalone information services companies.

For each of these alternatives, the assessment may address the general features of the organization and its ability to perform metering, data communication, and consumption history database activities. Each organizational model has some advantages and some disadvantages.

8.7.1. ALTERNATIVE: Commission Should Maintain Regulated Models

From the perspective of metering, communication systems, customer consumption history database maintenance, and bill processing, a regulated alternative would have the same responsibilities as the current IOU. A regulated monopoly would control most or all of the component services for operations, maintenance and installation, and would be subject to cost containment under PBR mechanisms.

Services Offered

Usage measurement, billing and pricing broadcasts could be offered as standard and optional services that the customer or ESP could elect, provided the minimal requirements met ISO/SC needs. Optional services could be based on customer class differences, density, and/or various customer- or industry-specific or ESP needs. Due to large size and degree of territory coverage, regulated entities may be more likely to expand beyond basic service functions into multiple energy (electricity, natural gas) and other commodities (domestic water, sewage), based on their selection of a metering and data communications systems.

Alternative 8.7.1. PRO:

1. Energy service customers encounter no problems shifting to or from suppliers (ESP or UDC)
2. It is relatively easy to preserve a continuous consumption history
3. Metering costs are reduced due to scale economies
4. Coordination of ISO/SC/UDC/ESP requirements less cumbersome than competitive models
5. All customers may benefit without cost-shifting regardless of who their Electric Service Provider may be.
6. Does not preclude additional alternatives for customers who desire them
7. Regulators have easy access to information needed.

Alternative 8.7.1. CON:

1. Once universal coverage implemented, monopoly status might impede technology innovation more than in competitive alternatives

2. PBR mechanism may provide less pressure for cost reduction compared to competitive alternatives

3. Customer negotiates meter cost and features, not UDC.

4. Customer retains control of usage records, not UDC.

5. Meters installed to satisfy ISO requirements may be indifferent to who installed, owned, or maintained them, therefore interface with the ISO should be readily facilitated.

6. Regulation of meter may stifle innovation and cost competition.

7. When the customer is responsible for his own meter costs there could be no cost shifting.

8. Universal deployment of RTP meters may impose added costs on customers without the prospect of offsetting benefits. When added to already excessive rates, the customers may revolt.

9. Preserving a continuous consumption history is not necessarily a problem for private enterprise.

10. Regulatory oversight may not be conducted "at arm's length" with a single institutional provider.

11. Metering costs may suffer from complacent institutional economy.

Alternative 8.7.1 entails three subpositions, which follow.

8.7.1.1. ALTERNATIVE: The Commission Should Continue with the UDC

The Commission assigned this responsibility to the UDC in their December 20, 1995 decision when they stated " In the restructured industry, they (utilities) would continue their obligation to provide non-discriminatory distribution services to all customers, including Direct Access customers, in their service territories. ". The meter is the end point of the UDC's distribution system. It is essential that all customers connected to this system receive consistent, safe and reliable service. In order to ensure this high quality service, the distribution system must be properly operated and maintained. If some customers are improperly connected , their metering could have a negative impact on all other customers. To ensure consistent, safe and reliable operation of the entire distribution system, the Utility Distribution Company (UDC) should continue to be the sole provider of metering for all customers on their distribution system.

General Features of the Organization.

From the perspective of metering, communication systems, customer consumption history database maintenance, and bill processing, an electric UDC could be imagined to have the same

responsibilities as the current IOU. It would be a regulated monopoly that continues to provide all of the component services of the distribution function and receives compensation for that service through the distribution charge. As a point of regulated stability during the implementation of competitive Direct Access, the UDC can continue to focus on providing superior distribution services to all customers.

Services Offered

The technology expertise and capabilities in routine metering, specialized metering and bill processing that the IOUs have developed and are continuing to improve would be retained and all ESPs could elect to take advantage of them. Usage measurement, billing and pricing broadcasts could be offered as standard and optional services that the customer or ESP could elect, provided the minimal requirements met ISO/SC needs. UDC control also ensures that meters are accurate, that new meter designs are certified before being installed, that specialized meters are available to customers, that the metering activity is conducted on a timely basis to ensure cash flow, that privacy of metered data is maintained as required by statute and that the distribution system continues to operate in a safe and reliable fashion. Third, the regulated utilities currently have systems and processes in place to provide meters to its customers. These include but are not limited to, competitive procurement contracts that take advantage of economies of scale, electric meter shops that are responsible for meter inventory management, acceptance testing, calibrations, meter repair, etc., quality assurance personnel that perform meter testing and certification. Optional services could be based on customer class differences, density, and/or various customer- or industry-specific or ESP needs. UDCs may also elect to extend services functions into multiple energy (electricity, natural gas) and other commodities (domestic water, sewage), based on their selection of a metering and data communications systems.

<u>Alternative 8.7.1.1. PRO:</u>

1. The quickest option for providing Direct Access by 1/1/98.

2. No changes in current UDC responsibilities are made, and existing utility staff resources and expertise remain in place and undisturbed.

3. Minimal changes to privacy statutes for customer usage data.

4. Experienced in the maintenance of consumption history.

5. Minimizes customer confusion for outage and basic service calls.

6. Familiarity with territory and customer-base served results in better quality of service.

7. The reliability and safety of the distribution system remains intact.

8. Non-DA customers also receive the benefit from whatever metering and data communications systems is installed.

9. Metering standards are in place.

Alternative 8.7.1.1. CON:

1. Potential for higher costs than monopoly INFOCO if natural gas and other commodities are excluded due to regulation and cost accounting complexities.

2. Coordination with ISO and/or SC requirements may still be more cumbersome than for a singular INFOCO monopoly.

3. Multi-site customers across two or more UDCs still have data coordination issues.

4. Competitive Direct Access suppliers may require proof that UDCs adequately protect data from access by their own affiliates.

5. The current monopoly on meter service is no more sacred than that over generation, customers may benefit if UDCs must compete for the meter business.

6. Ready availability of meters may allow customers to acquire them consistent with the customer's timetable.

7. It is possible that with proper incentives, competition can exceed the UDC standard of service. To assume the UDC may always be the superior service provider may not be correct.

8.7.1.2. ALTERNATIVE: The Commission Should Consider a Monopoly INFOCO

A regulated monopoly that meters, routes data across communication channels, maintains customer consumption history databases, and possibly renders bills for other organizations is an alternative option to multiple regulated UDCs performing this function. The term INFOCO has been developed to describe a standalone organization that conducts metering and data communication services organization. Like a UDC, it provides opportunities for economies of scale and greater expertise through specialization in functions that would not be likely for smaller companies.

General Features of the Organization.

The statewide monopoly INFOCO is an organization that is limited to metering, communication systems, consumption history database maintenance, and perhaps data processing for billing. It would not have responsibility for operating and maintaining the distribution system.

An INFOCO monopoly would offer the same services that multiple UDCs would offer.

A variation of this approach is the franchise INFOCO that bids to provide services for a geographically specified area. While there would be multiple INFOCOs, they would be time-

limited franchise monopolies in a given region. The advantages and disadvantages of this organization are virtually the same as for a regulated, statewide INFOCO monopoly.

Alternative 8.7.1.2. PRO:

1. Lowest cost per unit by having universal coverage and multiple commodities (electricity, natural gas, domestic water).

2. Multi-site customer using a single ESP may have fewer problems obtaining consolidated bills.

3. Advantages in dealing with vendors by virtue of large size.

4. Consumption database keeps seamless history across ESPs and UDCs.

5. No affiliate relationships to supervise.

Alternative 8.7.1.2. CON:

1. Least cost pressure or need to introduce technology by its monopoly status

2. To retain expertise, personnel and infrastructure, a monopoly infoco would have to be formed by "spin-offs" of the existing UDCs, requiring UDC compensation for asset turnover or monopoly INFOCO CTC charges

3. Likely disruption and confusion when UDC functions shifted to INFOCO and reconciled

4. Requires statutory changes concerning privacy.

5. INFOCO management of metering may have a negative impact on the safety and reliability of the distribution system.

6. Single point of failure for database and data communications systems.

7. May increase the amount of regulatory oversight required.

8. Difficult to have in place by 1/1/98.

9. Requires development of metering standards.

10. Cost per unit advantage does not exist unless gas utilities are enforced to participate.

11. Higher administrative costs for this new stand-alone entity.

8.7.1.3. ALTERNATIVE: The Commission Could Adopt A Hybrid Model: A Stakeholder-Owned Monopoly Clearinghouse

One way to balance the needs of all relevant parties is to create an information clearing house that is designed, owned and operated by all of them. The VISA bank card system is an example of this model. This is a not-for-profit company owned and operated by the member banks. It serves primarily as an information clearing house, allowing its members to compete in whatever entrepreneurial ways they choose while providing a necessary common resource that is managed cooperatively for the benefit of all. The following discussion is abbreviated, since much of the description of this alternative parallels the INFOCO monopoly, and many of the advantages and disadvantages are the same.

General Features of the Organization.

The Direct Access clearing house would be owned by those participants in the California market who intend to rely on its services. Its board of directors would be structured to contain a fair balance of all stakeholder groups—the ISO, the PX, the UDCs, schedule coordinators, consumer organizations, competitive providers, etc.—and to prevent domination by a few players. Its operations and management would be structured to perform the information flows required both for system operations and for healthy competition, and would modify its activities to adapt to the changing needs of parties as the market evolves. It would implement safeguards to prevent unauthorized access to data and would provide a process to investigate and resolve any complaints.

Services Offered

The clearing house would not have to perform metering activities directly, as long as the information that came to it satisfied various key parameters. The clearing house would control the specifications of the metering function, and could bid out the work, subcontract the work, or rely upon existing member organizations if clearing house rules permitted this. It would acquire metered usage data from all customer premises and other points as needed for system operations and settlements and dispatch this data to appropriate parties in a timely fashion.

Alternative 8.7.1.3. PRO:

1. The needs and concerns of all stakeholders are built into the design, creation and operation of the clearinghouse.

2. Achieves the economies of scale and scope of a monopoly, but without requiring regulatory oversight or government management.

3. Stakeholder control would enable the clearing house to adapt to changing market arrangements and conditions.

4. The requirement of commercial viability (no subsidies) would provide pressure to be efficient.

5. Many of the relevant parties already understand information issues quite well by virtue of their participation in the DAWG and other working groups.

Alternative 8.7.1.3. CON:

1. Delay of 1/1/98 implementation likely in order to ensure that the needs and concerns of all stakeholders are built into the design, creation and operation of the clearing house.

2. Requires creating a stakeholder governance structure with clear accountabilities.

3. Potential difficulty in reaching consensus agreements among stakeholder operators with wildly divergent interests (unlike commercial banks).

4. Requires new statutes, or revision of existing statutes, to address customer information privacy issues.

5. Requires creating a new monopoly entity.

6. While knowledge levels have certainly increased, it is by no means certain that enough relevant parties have the level of understanding of information issues required for this undertaking.

7. Lack of subsidies could result in demise of firm with disruption to customers.

8. Reliability and safety of distribution system likely to suffer.

9. May absolutely require regulatory oversight and/or government management.

8.7.2. ALTERNATIVE: The Commission Should Move Toward Competitive Models

A number of competitive alternatives exist. To many, the greatest advantage of these models is simply their unregulated status and the resulting invitation to innovation that is offered.

General Features of the Organization

Because of its competitive nature, it is difficult to make generalizations about the features of competitive models. Each one may look somewhat different based on its goals. However, competitive models do have some common attributes, such as profitability, customer/market-focused, opportunity for expeditious decision-making, and entrepreneurial spirit.

Services Offered

Services offered may be tailored to the market that competitor is targeting. This model is likely to offer the minimum information required by regulation for ISO settlement, etc. so that resources could be devoted to providing services that consumers may pay for.

Alternative 8.7.2. PRO:

1. Meter and data storage choices likely to be under strong cost reduction pressures, providing a benefit to the customer.

2. Technology diversity may introduce new products faster and be used to differentiate a particular company.

3. Customers are perceived to have more choice.

4. Many competitive businesses offer identical services with high transaction and very precise financial accounting requirements (e.g., Banks, credit cards, retailers).

5. Adding utility services to the existing client base could produce significant economies of scale.

6. Higher quality customer service with products customized instead of one-size-fits-all.

7. If UDC billing services are uncompetitive they should be abandoned, not propped up by a captive customer base.

Alternative 8.7.2. CON:

1. Lack of scale economies likely to limit potential for competitive cost reductions.

2. More difficult for customers to transfer among market participants.

3. Possible lack of experience in metering, communications, or billing.

4. Multiple companies create problems with assembling statewide data on timely basis for use by government.

5. Ensuring compliance with privacy of usage data is more complex in a competitive setting than for regulated monopolies.

6. Lack of universal penetration may preclude some technologies.

7. Multiple firms increase complexity of providing usage information to ISO and/or SC on a timely basis.

8. Dedicated systems likely to be underutilized, thus increasing costs per unit.

9. Competition might result in loss of market share and demise of firm with disruption to customers.

10. Existing UDCs are concerned that reliability and safety of distribution system are likely to suffer.

11. Existing UDCs are concerned that customers that lack appealing market characteristics never receive the benefits of competition.

8.7.2.1. ALTERNATIVE: The Commission Should Look to Energy Service Provider

The competitive Electric Service Provider (ESP) is a natural consideration for metering, meter reading and rate communication, billing, and customer-specific data management. These are but trade-specific terms for the classic components of marketing: the “place” (physical delivery), “price” (supply and demand determinants), “promotion” (validation of terms and conditions of sale), and “product” (specification of target markets) of electric service.

Billing is a natural function of a commercial business, and many businesses have undertaken complicated usage measurement at the customer's site and measurement transfer protocols to move these measurements to a central location as precursors to billing. Businesses throughout the world subscribe to billing services capable of processing a high volume of financial information and maintaining the security of the transactions. Examples include banks, credit cards, hospitals, retailers. The biggest third-party bill processor is GE Capital.

The ESP may be obtaining less than one half of the total electricity revenue for some small customers, with the remainder going toward distribution system fees, public benefit programs, and CTC requirements, during the first five years of the Direct Access period. The existence of these sizable revenue flows to other organizations may suggest that the ESPs share usage of metering and data communication systems results among the other service providers and regulated entities.

General Features of the Organization.

The organizational focus of a bilateral contract supplier or aggregator is oriented to matching generation supplies with customer loads. There may almost certainly be a high level of emphasis placed on detailed, customer-specific data and the efficient communication of that data. The relatively larger number of ESPs that could be expected versus other more centralized entities that might provide metering and data communication services implies that a strong ESP role may require a greater reliance on the development of industry standards. Greater efforts by the scheduling coordinator to ensure that the aggregated data needed by the ISO is available, may be required. Maintenance of a continuous consumption history across several private energy suppliers when the customer has switched would impose burdens not usually encountered in

competitive businesses. Therefore, the customers own records of energy consumption may obviate the need to rely on the UDC or third party service providers to obtain this information.

Services Offered

An ESP would conduct usage measurement with devices that served its needs most economically, and would be less inclined to be interested in the optimal methods to collect the information that others might require. The measurement, interim recording, and transmittal to the communication system would be accomplished using in-meter, standalone data storage devices, or communication system equipment selected to meet the ESP's needs. Meter certification would conform to standards established for the ESP, and it would meet this minimum standard through its own staff or contracting out this activity. Meter inventory management would be conducted as a business decision of the ESP, which might follow quite different practices than have traditionally been followed by integrated IOUs.

Alternative 8.7.2.1. PRO:

1) Customers are free to exercise choice.

2) Customers may receive special metering deals to sign with an ESP.

3) Customers control data.

4) Services and equipment are customized to suit customer needs.

5) As the central manager of energy flows, the ISO may provide one-stop service for government or private parties who require information on electrical consumption.

6) Customer escapes the arrogance of UDC's who may perceive that they, not the customer, know what is best.

7) It provides more incentives for innovation.

8) Competitive pressure to chose better performing technologies or business practices.

9) Customers having concerns about privacy of usage data have greater control over access to their data.

10) Greater diversity of communication systems encouraged by greater fragmentation of the market.

Alternative 8.7.2.1. CON:

1) Maintenance of continuous data histories may suffer, ultimately resulting in higher ISO imbalance costs.

2) Government would find it much more difficult to assemble timely statewide data compared to the more concentrated alternatives.

3) Ensuring compliance with privacy of usage data if customer data is in the hands of firms who can gain competitive advantage from it may be harder.

4) No scale economies compared to any of the other alternatives, thus increasing costs for the consumer.

5) Some communication systems precluded by low penetration rates resulting from fragmentation of the market.

6) Communication systems complexities likely to exceed resources/competencies/experience of energy suppliers.

7) Scheduling Coordinator role becomes more complex and prone to error.

8) No incentive to provide pricing signals or load shedding signals for arrangements apart from the ESP (ex. ISO ancillary services).

9) Requires development of metering standards.

8.7.2.2. ALTERNATIVE: The Commission Should Create Multiple, Competitive INFOCOs

In this option, multiple competitive INFOCOs exist to serve the mutual needs of ESPs, regulated distribution companies, and others needing information about energy usage. It provides opportunities for economies of scale and greater expertise through specialization in functions than would be likely for individual energy service companies, but not as great as those provided by a single INFOCO. It also provides a buffer between the services of the ESP and the customer by performing a customer service function that, if grouped with generation services, could provide a competitive advantage to the incumbent supplier over its competitors.

General Features of the Organizations.

The organizational scope of a competitive INFOCO firm is identical to that of a regulated INFOCO. Unregulated INFOCOs compete with one another, most likely bidding to provide metering and data communication services between the far more numerous ESPs and all of their end-use customers, but possibly arranging for these services with end-use customers. It is possible that financial institutions (banks, credit card organizations, etc.) could be aligned with INFOCOs to provide metering, communication, and billing services. These combinations would be more likely to be able to benefit from existing financial institution billing capabilities if no bill formatting requirements existed for energy bills.

Services Offered.

Usage measurement would be determined by each INFOCO independently assessing how it would meet the interests of the ESPs, regulated distribution monopolies, ISO/SCs, and perhaps end-use customers. The technology that the INFOCO selects to record usage may be subject to wide variances dependent on how much of the market share it was able to attract, the length of its contract, and how geographically cohesive its footprint is. It is possible that a limited number of competing INFOCOs could afford to have independent communication systems that provided two-way capabilities, but clearly sharing the market constrains the ability of any one INFOCO to achieve high penetration rates, and increases costs per customer for all INFOCOs. A large INFOCO would be likely to internalize meter certification and meter inventory as the large scale justified an internal meter shop. The INFOCO would either prepare a bill for the customer or deliver customer usage data to the ESP or UDC for them to prepare their own bill to the customer.

<u>Alternative 8.7.2.2. PRO:</u>

1. Greater scale economies exist than in the ESP alternative.

2. INFOCOs who can afford a communications system would be more likely to offer extended services than would an ESP.

3. End-use customers could switch among the family of ESPs using a single INFOCO with minimal delay or expense.

<u>Alternative 8.7.2.2. CON:</u>

1. Customers would still have to coordinate among INFOCOs when switching among ESPs using different INFOCO providers.

2. Scale economies lower than regulated alternatives.

3. To retain expertise, personnel and infrastructure, INFOCO would have to be formed by spin-offs of the existing UDCs, requiring UDC compensation for asset turnover or monopoly INFOCO CTC charges.

4. Likely disruption and confusion when UDC functions shifted to INFOCO and reconciled.

5. Requires statutory changes concerning privacy.

6. INFOCO management of metering may have a negative impact on the safety and reliability of the distribution system.

7. May increase the amount of regulatory oversight needed.

8. Difficult to have in place by 1/1/1998.

9. Requires development of metering standards.

8.8. Assessing Options to Determine Feasibility and Cost Implications of Alternative Technologies, Penetration Strategies and Installation Schedules

8.8.1. Metering Workshop and Taskforce

Once the basic working set of information requirements were established, the process to assess the variety of technical solutions available was initiated. The Metering Workshop, held on June 21, 1996, offered high level descriptions of the various technical alternatives and provided background on key features which impact feasibility and cost. Held in Sacramento with the cooperation of the National Meter Reading Conference, the workshop attendees benefited from the opportunity to see supplier exhibits first hand and from the participation of a number of suppliers who have not been active participants at regular DAWG meetings. The results of the information gathered at the workshop are described in Sections 8.8.2, 8.8.3, and 8.8.4.

Following the workshop, a task force of regular Direct Access Work Group participants convened to define specific Direct Access scenarios and to request information from a number of suppliers regarding recommendations and approximate costs to deploy real-time metering capabilities. Sections 8.8.5 and 8.8.6 describe the scenarios and the resulting supplier input.

8.8.2. Identifying Key Features Influencing Feasibility and Cost

This section addresses general questions that should be evaluated regardless of the particular technology or deployment strategy being evaluated. Typically, these are the types of criteria used to weigh the ability of a particular solution to solve the business problem.

8.8.2.1. Manufacturing Capacity and Lead Times

This feature addresses the ability of a supplier to provide the purchaser with the equipment ordered. Assessment of this category involves the following types of questions:

- Is manufacturing performed by the supplier, or sub-contracted?
- Does the supplier have the manufacturing capacity to fill the order?
- Are the manufacturers ISO 9000 certified (a measure of quality control)?
- Does the supplier have contracts in place for the raw materials required to manufacture the product?

- How much lead-time does the supplier require before order delivery can occur?

8.8.2.2. Installation

If the provider can and does elect to have others perform technology installation, questions about the ability of the installer to perform the work are required. For example:

- To what degree has the supplier performed this work in the past?
- Were the installer's former clients satisfied with the performance of the work?
- Are the installer's employees fully qualified?
- Does the installer have adequate resources to apply to meet schedule?
- Are appropriate work management and tracking tools used?
- Do the installers have the appropriate licenses or certification?

8.8.2.3. Coordination with Communication Carriers

Irrespective of the type of communications path to be used, and whether it pre-exists or must be installed, some coordination may be required. These questions primarily focus on logistics and operations.

- What permits and licenses are required and who may bear the cost?
- What level of coverage does the carrier have in the area to be deployed and does the carrier network within that network have the capabilities needed ?
- Is negotiation and coordination of multiple carriers required?
- What are the physical and environmental requirements for the network "links" and where may they be located?
- Where are the boundaries of accountability for error detection and problem resolution?
- What fail-safes, back-ups and alternative carriers are available and how may they be used?
- Who (supplier or purchaser) is responsible for securing the cooperation of the carrier?
- Are any fees to secure the communications carrier already included in the pricing quotes, or does the purchaser bear those costs separately?
- Who is responsible for the ongoing relationship with the carrier?

- Is the available capacity on the network adequate for the application being considered?

8.8.2.4. Maturity, Flexibility, and Obsolescence

Assessing the maturity of a supplier's product reduces the risk that the purchaser has received an excessively optimistic opinion of the product's performance. These questions allow the purchaser to make some assessment of the supplier's track record compared to the degree of risk the purchaser is comfortable taking.

- How many installations does the supplier currently have in place?
- How large are those installations?
- How long have they been in place?
- How many are "pilots" or "demonstration projects", compared to production systems/operations?
- Are the supplier's clients satisfied with the product/performance?

Flexibility typically refers to the ability of a product or service to adapt to changing market conditions or to changing technology.

- How much of the technology is based on proprietary standards versus open ones?
- Where in the architecture are the proprietary components located?
- What partnerships, strategic alliances, or MOU's does the supplier have with other suppliers? What are the expected results of those relationships?
- What other products interact and/or integrate with your products?
- May this technology be upgraded or compatible with future releases of the suppliers product? Of other suppliers' products?

8.8.2.5. Features and Performance

Questions about the features of the product or service allow the purchaser to determine if this product can meet the short-term and long-term needs the purchaser anticipates having. The purchaser may elect to select a product that only meets one (short-term or long-term), but doing so should be a deliberate decision, not an inadvertent one.

Capability generally refers to the list of functions the product or service offers (now or in future) and the point at which the technology in question is unable to provide/deliver the requested features.

- How much total capacity does the network have?
- How much of it is currently being used for other applications?
- What priority can the purchaser's application expect on the multi-use network?
- What kinds of information (i.e., data packets, voice, video, etc.) can the network transmit?
- How quickly can the network transmit from end-to-end?
- Can the system be expanded readily and economically?

Each of the categories above become critical components for metering and data communications technology evaluation. There are no "wrong" answers to any of these questions until the application (and information) requirements are applied. Once viewed in the context of the business need, the purchaser is able to narrow the selection of options and alternatives to those which best meet the criteria deemed most important.

8.8.3. Types of Meters

8.8.3.1. Solid-State Meters

Today, manufacturers are beginning to produce fully solid-state meters with interchangeable software features, which allow the consumer or provider to make changes to the measurements being captured by the device. Features such as power quality monitoring and harmonic tracking could be turned on and off as desired. Some meters have a dual connection, allowing one stream of data to flow through to the data collector and another to flow directly to the consumer. These advanced features are quite new and still costly, but consumers who want them have demonstrated the willingness to pay for them. Where the meter has a connection to some communications system, the consumer or provider may eventually be able to turn features on and off without scheduling a field visit to the device for reprogramming.

Manufacturers are currently working on the development of cards that could be easily swapped in and out of meters that would permit a variety of communications providers to seamlessly and fairly quickly connect to a particular device.

Solid-state meters have the capability to store large amounts of data for long period of time (depending on how much memory is purchased and installed in the device). Solid-state meters may range in cost from $150-$3000, depending on the features ordered.

8.8.3.2. Digital Meters

One of the more recent technology innovations is the application of digital technology on usage measurement. Several companies are bringing products to market that sample the sine wave as power enters the panel and interpolates usage based on the volts/amperes registered. If the meters, which are ANSI certified, actually perform as advertised, they may make inroads into the existing solid-state meter market share in the near term, with long term implications (as price reductions occur) for the electromechanical market in the long-term.

8.8.4. Descriptions of Technical Alternatives

The choice of technology to be used for Direct Access is highly dependent on the number of customers who participate, the size of the customer, the type of data required, the frequency of meter reading, and where these customers are geographically located. Each technology alternative must be capable of recording energy consumption on an hourly basis with the capability of daily meter reads to be suitable for Direct Access. Technical alternatives capable of providing Direct Access usage measurements that are available in the market generally fall into two major categories: 1) Meter-based alternatives, and 2) Communications- or Network-based alternatives. This section may provide a description of these categories and their sub-categories.

The following discussion focuses on the metering and data communications systems, and does not completely address the processing or storage of data, nor its transfer to other parties. Implementation of Direct Access may also require significant changes to the billing and customer data handling systems currently used by UDCs. The required changes are discussed in Section 8.2 of this chapter.

Communications/Network-Based Alternatives

There is a wide variety of data communications- or network-based alternatives in various stages of production or development. Typically, (but not always) they are characterized by 1) some type of connection or communications module which connects the output of the meter to the first tier of the communications network, 2) an interim “local-area” collector where reads from multiple meters are gathered and processed (to varying degrees), 3) an interim “wide-area” collector which routes data from the local collectors, 4) a “head-end”, the network manager responsible for controlling all the tiers below it and 5) the database, where all the information is eventually stored.

Advantages some networks have over a stand-alone metered solution are:

- Solid-state meters are not required in order to deliver Direct Access level usage measurement. Some telecommunication systems require digital input, but this can be achieved with either electronic meters or electromechanical meters with some type of analog-to-digital converter.

The network can acquire and store meter reads (via the module) at the necessary intervals required.

- Network-based solutions provide two-way communications directly to the customer premise thereby enabling customer choice.
- The network could be used for things other than electric meter reading.
- Network-based solutions could be expanded to provide value-added services to the customer
- The increased scope of services provided by a network-based solution may result in economies of scope and scale thereby decreasing the costs of providing these services.

8.8.4.1. Power-Line Carrier

Power-Line Carrier technology is typically used only with electric meters because it involves a connection to the actual electric lines as the communications carrier. The advantage for an electric utility is that the network is most already in place. The principle disadvantage is that it is not readily available for other uses, although development for other uses is conceivable. Another disadvantage is information capacity: Power Line Carrier system work rather slowly, as it must coexist on the lines with the 60 Hz power. In remote areas, however, PLC remains an alternative to be considered.

8.8.4.2. Telephone Line

There are two types of telephone based systems. One consists simply of solid state meters with a modem that could be read remotely. The second is as described in Section 8.8.4. Direct telephone line connection (whether the meter calls the “head-end” or vice versa), is the most commonly used form of network meter reading today. Telephone-based communication for meters has the apparent advantage of using a network that is currently in place in most locations. The difficulty, however, is that the telephone line is not necessarily co-located with the electric meter at the customer’s location and a telephone connection has to be made to each meter. This situation is exacerbated for unique metering locations (traffic lights, golf-course sprinklers and agricultural pumps, for example). While built-in phone modem costs have declined in recent years, running the telephone line and the physical interconnection to the meter could be costly. In addition to initial and ongoing costs, jurisdictional disputes between the electric utility and the phone company as well as scheduling work, have combined to limit the application of telephone communication technology to large customers where the economics are justified.

The growth of the competitive telecommunications industry has resulted in a number of emerging market players offering telecommunications-based solutions based on new technology developments. At this point in time, many of these projects are in pilot or development, so some

of them may not be available or attractively priced by 1/1/98. Nevertheless, these new projects are worth watching for future applicability.

8.8.4.3. Radio-Frequency Fixed Network

A radio frequency fixed network system is most effective where customer density is medium to high (i.e. metropolitan areas). The large scale of the deployment also permits a “blitzkrieg” approach to meter and data network installation, allowing large numbers of meters to be changed-out rapidly to coincide with the data network deployment.

Fixed networks are relatively new to the automated meter reading market (compared to telephone-based reading), but a robust market is beginning to emerge. A number of firms have gone beyond the 1000 meter pilot stage up to currently installed totals of over 300,000 meters, with contracts in place for over 800,000 network based meters and are actually collecting usage for billing purposes. Fixed networks could be used for other things, but are suited to short bursts of information (like a meter read) and are unable to handle long, large streams of information like voice and video. However, they have the costs to reflect that lower level of function. Fixed network providers typically have two-way networks from the interim “local” collector on up and have partnerships with building and home automation providers for development of energy related products and services.

8.8.4.4. Satellite Network

The continuing deployment of Low-Earth-Orbiting Satellites (typically called LEOs) may result in a cost-effective solution for rural and remote areas where fixed networks (wired or not) are not technically feasible. These technologies show promise, but have not yet gone beyond the pilot phase to full commercial production. Currently, not all the LEOs have been deployed, which also results in “holes” where no satellite coverage is available.

8.8.4.5. PCS/Cellular Network

PCS (Personal Communications Services) and Cellular networks are also technologies that may have the development of niche meter reading applications in mind, although this is not expected to occur within the 5-7 year time frame. The wait is largely due to FCC pressure on new PCS license holders to get infrastructure in place and utilized within 5 years (or lose the license). Industry analysts forecast that initial PCS focus may be solely on voice and paging traffic and that the narrow capacity used by metering applications may not make an interesting market until other markets with more lucrative revenue potential have been exhausted. In addition, PCS and cellular telephone networks require a level of data throughput and end-device complexity that results in inherently higher costs than current radio-frequency fixed networks optimized for meter reading and similar applications.”

8.8.4.6. Broadband Network

Broadband networks have, by far, the greatest capacity and capability. In some areas, notably San Diego and San Jose, broadband networks are currently being deployed and are planned throughout California, where they will bring their capacity and capability to the home. According to Pacific Bell, these networks costs are being justified by traditional telephony applications alone. Additional service such as video (the entertainment market), meter reading and home automation services will serve to lower the incremental cost of each service. This capability should be able to be realized with some of the lowest incremental costs of available technologies in the areas where broadband networks have been deployed. Broadband applications for meter reading are in pilot or demonstration phase at a number of utilities across the country.

Broadband networks are currently available and were selected by the Department of Defence for use as the Internet. Cable television has used broadband networks on a wide scale since the 1950s. Curent ongoing refinment of broadband technology has Pacific Bell demonstrating a completely addressable broadband network exhibiting a very high rate of location polling capability. Their network can have client servers that can interact with home based readers and management systems. They are now planning technical tests of their network systems with San Diego Gas & Electric Company and Los Alamos National Laboratory.

A clarification should be provided relative to the cost of the broadband network, i.e., investment in the infrastructure represents the initial investment outlay, offset by long-term reduced costs of operating and offering virtually unlimited services. The investment in infrastructure affords the converging industries of voice, data, information, and energy opportunities to create bold, new commercial offerings.

8.8.4.7. Hybrid Data Systems

There are numerous ways to combine the technology alternatives outlined above. For example:

- Solid-state meters could be hooked up to any of the networks, combining the desired advanced functions of the electronics with the advantages of the network.

- It is possible to use one network component (power-line carrier, for example) from the meter to the local collector, and then use another, (radio, phone, broadband) to transport the information the rest of the way

These are just a few examples of the flexibility that could be applied in order to achieve real-time metering for Direct Access.

8.8.5. Defining Appropriate Scenarios

8.8.5.1. The Matrix of Possibilities

Four different Direct Access deployment scenarios and four alternative timeframes were developed by a Metering and Communications Task Force, with review and approval by the Direct Access Working Group's Metering and Communications Team. The resulting sixteen scenarios were presented to a variety of industry suppliers along with a request for pricing information. The majority of the suppliers submitted at least some information, allowing the development of approximate cost ranges for each scenario. The results of that effort are presented in section 8.8.6.

8.8.5.2. Description of Deployment Scenarios Used for Requested Information

Scenario 1. Limited Deployment only, to All Customers over 100 kW.

Scenario 2. Narrow Deployment, to 100% Industrial, 25% Commercial and 10% Residential

Scenario 3. Wide Deployment, to 100% Industrial, 100% Commercial, 40% Residential

Scenario 4. Comprehensive Deployment of Real-Time Metering for All Customers

8.8.5.3. Time Frames for Deployment

Frame A. Accelerated Deployment in One Year: Beginning 1/1/97 and Completing 1/1/98

Frame B. Phased Deployment in Five Years: Beginning 1/1/97 and Completing 1/1/2002

Frame C. Delayed Deployment in Ten Years: Beginning 1/1/97 and Completing 1/1/2007

Frame D. Optimum timeframe as recommended by the Supplier

8.8.5.4. Scenario Assumptions

Consumer Group Size

- The study assumed 40,000 industrial consumers, 1.5 million commercial consumers and 8.5 million residential consumers, for a total of 10.4 million.

Consumer Distribution.

- The study assumed for each consumer group a geographic distribution of 85% urban and 15% rural.

Metering Requirements

- The study assumed the meter records data hourly, and may be polled daily or monthly using either onsite or remote access.

Size of the Project

- Suppliers were requested to assume that they would receive a contract to implement the scenario for the entire State.

8.8.5.5. Pricing Assumptions

Metering And Data Communications Systems Definition

The metering and data communications systems were assumed to include:

- Meter module, including certification
- Meter installation and calibration.
- Communication infrastructure deployment (hardware and software) for collecting meter data.
- System Integration of the ongoing process of meter reading, lost data 'fixing', data storage, and making data available to required parties
- Operations & Maintenance

Pricing Breakdown Requested

- Initial deployment cost
- Ongoing cost of operations and maintenance
- Cost differential for urban vs. rural installation

8.8.6. Results of Information From Suppliers

Of the seven suppliers solicited, six supplied pricing information and the set of assumptions used to reach the numbers provided. Two additional suppliers provided information or pricing on at least one of the scenarios. All pricing information was collated and minimum, maximum and average figures for each scenario and cost category were computed.

In order to protect the confidentiality of the information provided, which is normally submitted through closed competitive bids, direct quotations from suppliers may not be made available through this report. This approach was discussed in the working group meeting and approved.

In addition, it is important to recognize that suppliers were provided with very high-level, gross assumptions and were given only seven days to submit their information. Therefore, the information could be interpreted as no more accurate than general ball-park figures, useful for order of magnitude, but requiring the application of significant additional effort to increase levels of accuracy.

Finally, we note that although suppliers could have taken this opportunity to "game" the numbers in order to drive the results to a particular conclusion, no evidence that this has actually occurred has been detected.

8.8.6.1. Supplier Recommendations

The following recommendations could be extracted from the pricing and assumptions information provided by the suppliers:

- Complete deployment of real-time metering by 1/1/1998 was not considered feasible from a cost or schedule perspective by all but one supplier, who recommends it as their most cost-effective solution
- Two-thirds of the suppliers recommended 100% deployment of real-time metering by 1/1/2002 as their most cost-effective solution
- One supplier recommends a phased approach based on the demographics of each service territory, but was unable to provide costing information based on the information provided
- All suppliers submitted solutions that utilized multiple combinations of meters and communications networks in order to provide complete coverage
- If deployment were geographic, as opposed to random, costs would be reduced
- Increased costs to install in rural areas are largely associated with increased labor costs

8.8.6.2. Pricing Information

Pricing information from industry representatives is presented in Tables 1-12, and is presented in two formats. The first format is a purchase scenario in which a utility or other entity purchased telemetering equipment for hourly metering. The "Purchase" scenario includes a capital cost ("Total System Cost" and "Cost per Customer") and an operating cost per meter per year . The second format is a monthly service in which a third party owns the metering equipment and

provides it on a fee-for-service basis, per meter per year. In this case there is no up-front cost, only on-going costs.

Because metering suppliers did not provide pricing for both formats or for all scenarios, there are apparent inconsistencies in some of the results. For example, the average operating cost for the Purchase format for Scenario 4B is $20 per customer per year, while the total range of the Service price, which includes all of the capital, ranges from a low of $10 per customer per year to a maximum of $25. This large disparity is the result of supplier's using different technologies and approaches and illustrates the complexity of comparing alternatives.

Scenario 1: "Limited" Deployment Only, to Customers Over 100KW

Scenario 1A: Limited Deployment, Complete by 1/1/1998:

	Low	Average	High
Total System Cost:	$60 Mil.	$145 Mil.	$230 Mil.
Cost Per Customer:	$175	$1100	$2000
Annual System Costs:	$280 Thou.	$670 Thou.	$1,000 Thou.
Annual Cost per Customer:	$3	$3	$3
No Lease Costs Submitted			

Scenario 1B: Limited Deployment, Phased-In by 1/1/2002			
	Low	Average	High
Total System Cost:	$60 Thou.	$70 Thou.	$80 Thou.
Cost Per Customer:	$200	$450	$700
Annual System Costs:	$140 Thou.	$600 Thou.	$1,000 Thou.
Annual Cost per Customer:	$1.25	$2	$3
Annual Leasing Costs:	$9.6 Mil.	N/A	$21 Mil.
Annual Lease per Customer:	$240	N/A	$500

Scenario 1C:Limited Deployment Completion Delayed until 1/1/2007:
Same as 1B

Scenario 2: "Narrow" Deployment of Real-time Systems, to 100% Industrial, 25% Commercial, and 10% Residential

Scenario 2A: Narrow Deployment Completed by 1/1/1998:			
	Low	Average	High
Total System Cost:	$140 Mil.	$330 Mil.	$550 Mil.
Cost Per Customer:	$110	$270	$450
Annual System Costs:	$5 Mil.	$40 Mil.	$75 Mil.
Annual Cost per Customer:	$5	$32	$60
No Lease Costs Submitted			

Scenario 2B: Narrow Deployment, Phased-In by 1/1/2002:

	Low	Average	High
Total System Cost:	$135 Mil.	$250 Mil.	$400 Mil.
Cost Per Customer:	$110	$200.	$300
Annual System Costs:	$1.5 Mil.	$30 Mil.	$77 Mil.
Annual Cost per Customer:	$1.50	$25	$65
Annual Leasing Costs:	$10 Mil.		$20 Mil.
Annual Lease per Customer:	$10		$15

Scenario 2C: Narrow Deployment, Completion Delayed until 1/1/2007:

Same as 2B

Scenario 3: "Wide" Deployment of Real-time Systems, to 100% of Industrial, 100% of Commercial, and 40% of Residential

Scenario 3A: Wide Deployment, Complete by 1/1/1998

	Low	Average	High
Total System Cost:	$500 Mil.	$800 Mil.	$1,100 Mil.
Cost Per Customer:	$110	$165	$220
Annual System Costs:	$15 Mil.	$155 Mil.	$300 Mil.
Annual Cost per Customer:	$3	$30	$60

No Lease Costs Submitted

Scenario 3B: Wide Deployment, Phased-In through 1/1/2002

	Low	Average	High
Total System Cost:	$520 Mil.	$870 Mil.	$1,200 Mil.
Cost Per Customer:	$90	$180.	$240
Annual System Costs:	$6 Mil.	$110 Mil.	$310 Mil.
Annual Cost per Customer:	$2	$25	$65
Annual Leasing Costs:	$60 Mil.		$180 Mil.
Annual Lease per Customer:	$11		$20

Scenario 3C: Wide Deployment, Completion Delayed until 1/1/2007:

Same as 3B

Scenario 4: "Comprehensive" Deployment of Real-time Systems, to All Customers of All Classes

Scenario 4A: Comprehensive Deployment Complete by 1/1/1998

	Low	Average	High
Total System Cost:	$900 Mil.	$1,200 Mil.	$1,500 Mil.
Cost Per Customer:	$90	$120	$150

Annual System Costs:	$25 Mil.	$240 Mil.	$450 Mil.
Annual Cost per Customer:	$3	$25	$50
No Lease Costs Submitted			

Scenario 4B: Comprehensive Deployment, Phased-In through 1/1/2002			
	Low	Average	High
Total System Cost:	$870 Mil.	$1,600 Mil.	$2,400 Mil.
Cost Per Customer:	$90	$160	$240
Annual System Costs:	$12 Mil.	$170 Mil.	$470 Mil.
Annual Cost per Customer:	$2	$20	$50
Annual Leasing Costs:	$115 Mil.		$210 Mil.
Annual Lease per Customer:	$10		$25

Scenario 4C: Comprehensive Deployment, Completion Delayed until 1/1/2007:
Same as 4B

8.8.7. Conclusions About Alternative Technology Options

The goal of the exercise was to provide the Commission with a general impression of implementation costs and to discover trends or variances among the various combinations of scenario and timeframe.

In evaluating the pricing figures, the following observations are of note:

- The impact of a one year deployment was significant. Most suppliers found the scenarios based on this timeframe unfeasible, and did not even submit figures. Of those submitting

figures, the variances between min and max stayed constant over all 4 scenarios, suggesting that density was not a determining factor in this instance.

- The differences in pricing figures for 5 year versus 10 year deployment timeframes was nominal, suggesting that 5 years is the optimum period for deployment and that slower deployment does not result in installation or manufacturing economies. On the other hand, slower deployment has implications for technology improvement being excluded.

- The increase in costs per customer in scenarios 1 and 2 (compared to 3 and 4) reflect the higher costs (in advanced metering and phone-based communications) which characterize large commercial and industrial metering

- The decrease in costs per customer between Scenario 3B and Scenario 4B are a direct reflection of the lower residential penetration of Scenario B (100% residential versus 40% Residential). Cost differentials for Industrial., Commercial, and Residential classes were not available.

- Conclusions on the basis of average costs have little value as the input from one the suppliers skews average costs upward.

- Features offered by the suppliers included support for real-time metering requirements with several suppliers offering additional features (on-request reads, outage detection, tamper notification) as part of the total cost and others offering them for additional fees.

- To cover large geographic areas, fixed network solutions, on a purchase or leased basis, provide the lowest cost alternative and could be deployed in volume much more quickly than hard-wired telephone based systems. With a large deployment, the cost per customer for the fixed network solution is approximately $100 (one time cost) and under $1.00 per meter per month (ongoing service charge), although these numbers reflect overall system averages. Costs for industrial and large commercial customers are likely to be slightly higher and those for residential and small commercial customers lower based on costs to serve and metering preferences. In contrast, hard-wired phone line installations cost between $1,000 - $2,500 per meter (one time cost) and $18.00 - $30.00 per meter per month (ongoing service charge).

- While each of these technologies may be most appropriate in different situations, it should be noted that there is a break-even point based on the total costs for installation. If more than the break-even number of customers required a real-time meter, a fixed network solution would be most appropriate and have a lower total cost for installation, regardless of where the customers were geographically located. The installation of this type of system also enables customers to "hook on" to the system in the future with more of a "plug and play" process. The major issue with this scenario, however, is if just over the break-even number of customers elect the real-time metering, who pays for the network that has been installed system wide that is capable of providing service to all customers. This issue of affordability may not be as much of a concern if the majority of these customers were industrial and

commercial customers, whose costs would still be lower than if the phone option were utilized

- If less than the break-even number of customers require real-time metering, it would be more cost effective to install individual meters with phone lines. While it makes economic sense to use this technology, installation issues would need to be addressed immediately, as these installations are currently time consuming and resource intensive.

Finally, installation of a fixed network pre-supposes that there is a party or parties willing to invest the capital required to provide universal real-time metering to all customers in order to facilitate retail competition. Given the significant operational and ancillary benefits of fixed networks mentioned in Sections 8.8.4.3, including benefits for customers who have not yet elected Direct Access, this option should not be summarily dismissed from consideration simply because it requires wide-scale deployment of infrastructure.

Although the systems quoted meet the minimum requirements, it is important to differentiate between a system that may only meet the minimum requirements and one that, when installed, may provide the following additional characteristics at no additional cost:

- connection to an in-premises network,
- full two-way communications to the home (there is no need to bear the additional cost of a paging system for example for real-time pricing),
- additional capabilities like load profile in 5 minute increments for 100% of the customer base, and
- the meter modules use open communication protocols allowing multiple vendors to build the same module. This may decrease switching costs for the consumer and operators that may have the effect of lowering prices.

When looking at price it is therefore essential to compare full system implementation costs with values derived. At least one of the systems quoted has been designed to be expandable and to accommodate a robust set of features beyond the minimum requirements.

8.8.7.1. Net Cost of Metering

Evaluating the cost of telemetering-based hourly metering requires that the costs shown in Section 8.8.6 be reduced by the amount of operating savings that UDC's actually realize in implementing such metering. Such savings may be zero or negative, or could be highly positive. If only a small number of customers receive communications-based hourly metering, the UDC saves little or nothing, and may have higher costs associated with handling hourly data where monthly data is now handled. If all customers are automated with telemetering, the UDC realizes savings in meter reading and many other areas, as enumerated in Section 8.2.

Quantifying the benefits of telemetering is difficult and highly specific to individual utilities. Factors that affect the cost savings of implementing telemetering include the age and geographic distribution of the utility, the age and type of assets - including number of meters that must be replaced during implementation - current costs for meter reading and customer service, number of indoor versus outdoor meters, customer mix (residential, commercial, etc.), and other factors. Accordingly, savings reported by utilities that have implemented telemetering cannot be used to forecast other utilities' savings directly.

However, experience of other utilities can provide insight into the magnitude of potential savings. A number of studies have been published in the industry literature. One of the most detailed and most recent studies was presented at the 1994 Automatic Meter Reading Association annual symposium by Public Service Colorado (Seventh Annual AMRA Symposium Proceedings, Automatic Meter Reading Association, 1994, pages 212-229), a combined utility serving 1.9 million electric and gas customers. For a project involving 334,000 meters, PSCo reported projected savings in numerous operating categories having a total present value of $37 million (op cit. page 220), averaging $111 per customer (automation costs, including data processing, must, of course, be subtracted from this amount). Expressed as annual amounts, these savings average of $13.44 per customer per year.

8.9. Developing Standards for Meters and Communication Systems

As the competitive retail energy market emerges, the number of players with a vested interest in access to usage measurement information may increase exponentially compared to current levels. To mitigate the complexity resulting from competition, the adoption of a set of standards to govern metering and data communications systems is highly desirable. All stakeholders can agree, conceptually, that standards adoption may facilitate the implementation of Direct Access and consumer choice. Regrettably, consensus regarding the actual standards to be adopted has not emerged. This section attempts to clarify the discussion of standards for metering and data communications systems and provide a recommendation for proceeding with standards adoption.

In considering standards, the Commission must be clear about its objectives. Standards, like regulation, bear a cost: they limit innovation. Standards also delay implementation, and the delay could be very long, if imposed by government. Technology standards are most effective when they result from interaction of participants in a free market; for example, consider the success of TCP/IP as a market standard as compared to OSI protocols specified by the International Standards Organization. Presumably, the Commission’s interest in standards is to promote competition, whether by competing service providers or competing technology suppliers. Where vigorous competition exists and could be expected to continue, the a priori assumption should be that no standard is required. The metering and data communications markets are among the most competitive markets associated with the electric industry. Finally, the Commission should be aware that extensive standards already exist in metering and data communications. These are described in the sections below.

Standards could be broken into two major categories: 1) Standards required for Performance of Work , consisting of production, maintenance and installation operations (as discussed in Section 8.6), and 2) Standards required to ensure access to required usage measurements by all authorized stakeholders, consisting of hardware and software.

For the purposes of discussion, the term “Standards” is used in a generic sense and includes standards, specifications, rules, policies and procedures, and other requirements.

8.9.1. Standards for Performance of Work

This section attempts to describe the types of performance standards that may continue to assure consumers of reliable, accurate and safe connection to utility distribution systems.

8.9.1.1. Standards for Metering and Data Communication Systems Operations

In the case of production operations, performance standards, not product specifications, are needed to insure efficacy, efficiency, reliability, compatibility and safety of the systems. The stakeholders may need to define these performance standards. Section 8.9.7.2 will discuss a process for accomplishing this task.

Standards for meter reading accuracy and timeliness, and transfers of meter data to other parties are just a few of the performance standards that must be included in the metering standards for operations.

8.9.1.2. Standards for Maintenance and Installation of Metering and Data Communications Systems

Should the Commission elect, installation and maintenance operations relevant to revenue meters could be done by pre-qualified firms including: meter installation firms, electrical contractors, power suppliers (retailers), third party metering firms as well as the UDC. Firms may need to be pre-qualified based on their technical skills, training, and ability to safely and reliably install metering equipment according to set standards.

Third parties that install meters must be subject to metering installation standards, which initially should be based on current UDC standards and applicable governmental codes, ordinances, and rules pertaining to metering equipment, including safety and reliability requirements. All metering installers should accept responsibility and liability for any work performed.

While meters have typically required low levels of maintenance, the useful life of a solid-state meter is currently unknown but expected to be shorter than that of conventional electromechanical meters. Appropriate quality standards may be required for meter maintenance and repair. Questionable meters could be tested at any time, although testing costs could

eventually be passed on to the party questioning the accuracy. If found out-of-tolerance, meter testing and repair or replacement costs would likely accrue to the owner, unless another party has accepted that responsibility.

8.9.2. Standards for Hardware and Software

Where an industry standard already exists, common sense suggests that the industry standard should be adopted. In the absence of an industry standard, the arguments surrounding standards adoption coalesce into two fundamental alternatives, each associated with different categories of risk. Section 8.9.3 addresses metering and data communications systems components where standards already exist and recommends their adoption. Section 8.9.4 addresses components where no industry standard prevails and describes the alternative strategies for resolution.

If regulation mandated elements are deemed necessary in any portion of the system, then industry standard, open interfaces should be required at all interfaces.

The first point of the efficiency of a free market system in best protecting customers is evident. To illustrate the potential problems with regulation, examine the current proceedings that are focused on providing a minimal cost solution to accomplish meter reading. A free market may well (and probably would) decide that value added services enabled by an adequate communication system may provide entrepreneurs with enough opportunities that they may provide meter reading free to customers. The regulatory process inevitable must focus on cost, the free market allows and encourages a focus on customer value.

The second point follows directly from the free market principle by stating that if customer funding is applied to system costs, then all interfaces to the system should be based on open, non-proprietary industry standards. This does not preclude participants from implementing proprietary systems as long as no system funding is subsidized by the rate payer. To illustrate this point, if the regulators decide that the customer may pay for a Direct Access system through rates, then the components of that system must be open to access by all potential vendors of services.

The implicit assumption here is that given open interfaces the market may drive toward solutions that maximize customer value.

8.9.2.1. Why Open Standards?

The emphasis on Open Standards at all interfaces should be encouraged because:

- Open Standards enhance the potential for competition among potential providers. Competition is the best method of insuring lower costs and maximizing customer service. This follows since open standards would allow customers to switch providers if they were unhappy with the cost or value of the service provided.

- Open Standards enable third party providers to develop new products or services that utilize the communication infrastructure. For example, a refrigerator manufacturer could incorporate a standards-based integrated circuit into his product. The manufacturer would do this if it had value to customers as a means of saving money on energy bills or of automatically alerting the customer or energy service provider that efficiency is down or repairs are required. The benefit to the manufacturer is that he has a more valued product at a slight increase in price. The benefit to the consumer is that he may save money on energy bills and potentially have new automatic reporting features. The benefit to the energy services provider is that there are new offerings that can be made to customers with little or no additional cost to provide the service. This win-win-win situation is available only if open standards are embraced.

8.9.2.2. CEBus Is An Open Standard For Customer Premises

The most critical point in the system for standards based communications is within and around the customer premises. This is true because this is where the customer can interact with he system and hence the point of highest potential for value added services. Currently, the only truly open standard capable of efficient operation in this environment is the Electronic Industry Association (EIA) IS 60 spec based on CEBus technology.

Similarly, the American Meter Reading Association (AMRA) has developed standard table formats for presenting data from metering devices.

A comprehensive treatment of communication standards for the utility industry is contained in the Electric Power Research Institute (EPRI) Utility Communication Architecture.

8.9.3. Use of Existing Industry Standards

8.9.3.1. Existing Standards for Metering and Metering Devices

Meter installations include Potential Transformers (PT’s), Current Transformers (CT’s), metering cabinets, test switching systems and ancillary equipment.

Standards requirements help ensure that the correct meter and metering device combinations are used, in order to ensure accurate, reliable and safe metering that provides the necessary data. Standards for metering devices are defined primarily in ANSI C.12, which is a collection of accepted industry standards for electricity metering. These standards have been developed over many years, and incorporate the experience and expertise of many manufacturers, utilities, and other stakeholders. Meter standards are accepted and used for manufacturing by meter suppliers and for meter specifications by electric utilities.

Utility metering specifications typically supplement the ANSI standards with utility- specific operational requirements and optional functions, which are driven by accepted methods for connecting to their particular distribution system as well as all governmental codes, ordinances,

and rules that pertain to metering equipment, including safety and reliability requirements. A typical utility specification may include calibration and testing requirements, a listing of which meter types are acceptable, nameplate information and numbering required, as well as other requirements.

Adoption of the existing utility standards, including utility metering specifications may help advance the implementation of customer choice by eliminating the delays associated with development of new metering standards.

Appendix G lists the components where metering standards exist. Appendix H lists the relevant ANSI standards. Section 8.9.7 will discuss an approach for adoption, communication and monitoring of standards compliance.

8.9.3.2. Standards Exist for Meter Forms

The various standard forms correspond to the various standard electric service configurations designed to meet customer specific power requirements. These service configurations are based on specific customer loads and power equipment requirements which vary in many different capacities (5 to 4000 amperes), voltage levels (120 to 230,000 volts), transformer connections (star or delta), base configurations (socket, A-base, or switchboard), phases (single- or poly-phase), and even the number of service wires (2-3-4).

Form requirements for meters help ensure that the correct meter and socket combinations are used, in order to ensure accurate and safe metering installations. Form standards are accepted and used for manufacturing by meter suppliers and used for meter specifications by electric utilities. Not all utilities accept all standard forms (utilities generally accept a limited number of the available forms based on the characteristics of their distribution systems). All new service installations in the state could be accommodated with no more than three standard forms, with CTs and PTs, as required to match voltage and current levels.

8.9.3.3. Standards Already Exist for Meter Protocol Translation

Solid-State (Electronic) Meters and Interval Data Recorders (IDRs) store the information they collect on computer chip sets designed by each meter manufacturer. Due to the fiercely competitive nature of the metering market, these chip sets are programmed with proprietary protocols (sets of instructions) that are unique to each manufacturer. Meter manufacturers continually seek lower cost, higher function chip sets to differentiate their products in the marketplace. Most solid-state meters could be programmed to collect similar sets of information, but without access to the meter’s protocol, the information cannot be “decoded” so that it could be read by mainframe or personal computers.

In response to market requirements for translation of multiple protocols, a product emerged which provides “universal” meter protocol decoding. This product is called MV-90, the Multi-Vendor Translation System, developed by Utility Translation Systems, Inc. . This product not

only supports protocol translation of the meters developed by multiple manufacturers, it also supports translation of virtually every protocol used in the last decade. This allows utilities to take advantage of new products developed by the meter manufacturers (which take advantage of the increased capabilities and lower costs of the latest computer chip sets), while allowing "older", but still functional, equipment to continue to be used and useful. Further, MV-90 translation formats the data so it could be accepted by the utility billing and customer service system computers. In the Direct Access environment, this feature may facilitate access to usage measurement by multiple participants.

For many years, the metering business has been a highly competitive, unregulated, market-driven enterprise. In fact, lowest cost per highest function is reputedly the major market driver.

The Commission should not bind itself and the state to a proprietary protocol, yet it need not require the replacement of every solid-state meter currently installed (most commonly at the installations of large consumers of energy), To reconcile the existing practice of every major utility in the country, that of using MV-90 or equivalent for protocol translation, with the undeniable propriety of advancing toward the open system interconnectivity architecture, prevalent in the rest of the world of electronic data processing and communications, the Commission should allow a period of dual standards. After about five years, a remarkable product like MV-90 should have no trouble reconciling itself with competition as well.

It should be noted that the MV-90 capability to process Direct Access data has limits that may fall well below the numbers associated with any significant penetration of Direct Access within the IOU service territories. Experiences in Great Britain have shown that a practical limit for an MV-90 processing Direct Access data is in the range of 3000 to 5000 meters. Additional MV-90s could be deployed, but there are practical limits to that practice, too. The MV-90 is not a practical system for universal Direct Access, with 10 million customers, since it would take at least 2000 MV-90 systems to process the data.

Appendix I describes the MV-90 Translator in greater detail.

8.9.3.4. Industry Standards Already Exist for Network Communications Protocols

In the early 1970's, the International Standards Organization (ISO) developed the Open Systems Interconnection (OSI) model to define specific functions for each of several layers of functionality that are involved in network communications, with the goal of international standardization of computer network protocols. The protocol called TCP/IP follows a similar model [although it does not directly follow the OSI model, having been developed through a more expeditious process in the Internet Engineering Task Force (IETF) of circulation and revision of Requests for Comments (RFC)].

The available metering systems vary in their physical methods of communication for remote reading, and may vary in their methods of measuring electricity use; these functions correspond

to the highest and lowest levels of the OSI model. (In contrast, communications over backbone lines between metering agents and the ISO will need to follow the ISO's requirements at all levels.) These levels do not need standardization, while the intermediate levels do require standardization due to the need to preserve as much meter functionality as possible if a customer chooses service from a different vendor. Notably, the levels where standardization is needed are the same as those where the TCP/IP communications protocol provides a standard: TCP/IP supports a wide variety of application needs, and makes no effort to define the underlying network physical connectivity. Indeed, TCP/IP is used over a variety of physical media that is similar to what meter manufacturers are proposing for remote metering: radio, coax cable, twisted-pair wires carrying voice-grade (or lower) analog signals, and fiber optic (as well as ISDN, Frame Relay, etc.).

The need for standardization does include a common high-level communication format at the OSI Presentation level, just like Telnet, FTP, and HTTP are common high-level formats that allow Internet communications to occur. TCP/IP can accommodate extensions of the services that can be provided to customers over the same communication circuits (particularly Internet-based services); TCP/IP is used on all leading computer systems (MS-DOS/Windows, UNIX, Macintosh, etc.).

A few examples may help clarify the major points. First, consider a pager. The service company that provided the physical device had alternative models with different characteristics, but the company could communicate with all of them. If one were to change to a different service company, the new company could also communicate with the same pager, because they would use a common communications protocol.

Second, consider a mailing list through Internet e-mail that concerns any given topic. Some people use conventional Internet connections while others use packet radio, but can all communicate because all use a common communications protocol. Subscribers may use a variety of computer systems and mailer application programs, which are all compatible because they follow the standards.

Similarly, establishing a common protocol for communications between meters and higher levels of the utility system can allow for communications between different physical metering devices and over different communications media. The agent requesting metering data does not need to know whether the meter is read from a pole-top, a substation, or via the cable TV company, but just where to route its request to a device that can find the metering data. The Commission does not need to establish an exclusive metering system, but instead can allow alternative data communication suppliers to offer the services that they feel will be competitive, and can allow meter vendors to continue innovating to serve their markets.

8.9.3.5. Industry Standards Already Exist for Database Access Language

Regardless of the actual database selected for use by the provider of usage measurement data, the database must be ANSI Standard SQL-compliant with no usage of non-standard extensions. SQL (Structured Query Language) meeting ANSI X3.135-1992 (Information-Database Language - SQL), ANSI X3.168-1989 (Information-Database Language -SQL -Embedded SQL), and ANSI/ISO/IEC 9579-1-1993 (Information Technology -Remote Database Access -Part 1 Generic Model Service and Protocol) is the industry standard for cross product/platform relational database access language.

8.9.4. Alternatives For Components Without Industry Standards

Selection of a technology standard in the absence of a prevailing industry standard can be a two-edged sword. If the standard selected emerges as the industry standard, you “win”; if it does not, typically, you “lose”. On the one hand, a standard may be embraced by the marketplace and value-added retailers may rapidly develop innovative products based on it; on the other, over time, the number of products compatible with your standard diminishes and obsolescence results.

To guard against this risk, some advocate the adoption of an “open” standard. Open standards are preferable where they exist, but it is important to note that standards become “open” as the result of market forces. Typically, the supplier of a product with a proprietary standard decides that they would rather have, for example, a 10% share of a $10 billion market than a 50% share of a $1 billion market. By publishing their standard (thereby opening it to others), they create a domino effect which results in at least two positive outcomes: 1) value-added retailers can invest in new product development based on the standard and 2) consumers feel both less at risk for obsolescence and less chained to a single supplier. Both outcomes increase the revenue potential of the overall market.

The telephone industry’s RJ11 jack is a good example of how this phenomenon occurs. Prior to the advent of the industry standard RJ11 telephone jack (a universal connector to a telephone line) only a hard-wired voice telephone was available to the average residential customer on a standard voice grade telephone line. The RJ11 has allowed a variety of products ranging from voice telephone to fax machines to personal computers to be connected to the telephone network. These devices are now manufactured by hundreds of companies and offer features that were only dreamed of 30 years ago.

8.9.4.1. Adopt Telemetry Standards Such As TCP/IP

Another view is to adopt metering communications standards that allow for a hierarchy of protocols leading to a recognized standard like TCP/IP, where it makes sense in the network, but also allowing the equipment manufacturers to use their own good engineering practices and economic realty at the meter or the meter communication module. This approach does not eliminate from consideration TCP/IP at the meter or meter communications module, nor does it

eliminate another protocol like Hayes AT Command Set for phone based communication, it only opens the possibilities to the manufacturer for more cost competitive implementations where they make sense.

8.9.4.2. Meter-Telemetry Interface Standards

Metering communications could be viewed as communication between computers, thus allowing for the application of standards, with their resultant benefits, that are available from the computer-based data communications world. However, the general application of a computer networking analogy to meter data acquisition applies an inappropriate model. Computer network communications are characterized by significant amounts of data (several thousand characters) and frequent communication (many times per day). Meter data acquisition, on the other hand, involves a few hundred characters of data and, even with real time pricing, may rarely communicate more than once every fifteen minutes. The computer analogy carries with it the assumption of significant computational capability in every computer on the network (even to the extent of dedicated communication microprocessors on many local area network interface cards). Extension of computer local area networking concepts to meters implies the addition of significant processing power and its consequent cost.

But a meter is not like a computer–a meter is a telemetry peripheral that needs to communicate in the simplest, lowest cost, most direct fashion. For telemetry peripherals, multi-layer protocol stacks (used by computers) are usually collapsed to two or three simplified layers–typically a physical link layer specifying the physical signaling and a data link layer specifying one or more message formats. Where the relative cost of communications has to be low, manufacturers of meters and meter modules adopt simplified, often internally developed, protocols in order to keep costs down and remain competitive. Where higher communications costs are justified, as in industrial or large commercial metering applications, data requirements escalate and communication complexity escalates (as does cost). Simply put, protocols are used that match the economic and data requirements of the application.

8.9.4.3. Performance Standards and Innovation

Properly implemented standards can achieve all of the objectives listed in the previous section while also facilitating adoption of technology innovations. Performance standards, not product specifications, are needed to insure efficacy, efficiency, reliability, and safety. The users of a system are expert in what they need; the manufacturers are the experts in how to build it.

8.9.4.4. Accessing Data by Intranet For Processing By Multiple Parties

For Direct Access, the meters may have to be read daily, the data processed, and the data sent to all parties associated with the transaction. Current UDC systems are not set up to store or process daily data or transfer the data to other parties daily. These systems would have to be

upgraded to provide this capability. The data transfers would have to be electronic since all parties may require the data on a timely basis. This capability would also have to be developed or upgraded. Standards may have to be developed to insure accuracy, timeliness, reliability, security, and compatibility of the data transfer system. In addition to system upgrades or development due to the increase in data volume, communications and data format protocols may have to be developed to facilitate the transfer of data among all parties in a timely, reliable, and accurate manner. Unbundling of electric energy related services may also increase the information processing requirements. Since energy charges, distribution charges, and transmission charges may be calculated with totally separate pricing, the complexity of the billing process may increased. The customer's bills may be more complicated since each of these charges may be a separate line item on a bill, compared to a single item on current bills.

All metering and metering communications may be required to comply with, and be compatible with existing and future metering systems. The communications systems of the recipients of the data should also be considered.

We expect that security technology, currently being developed for Internet/Intranet commerce, may be usable for this application. The assumption is that TCP/IP (the Internet protocol) is the communications technology that makes the most sense, and meets the need to use economical technology so that small business are not unfairly burdened. Secure Sockets is one security method for Internet/Intranet messaging that may be appropriate.

Bi-directional and robust usage data may be a cost efficient system.

Planning should not be limited to a unidirectional data flow. The customer's future needs of how their usage data is or could be used must be incorporated into plans. Data must be accessible to the customer. Communications must be two-way so that energy management systems, analysis products and other innovations are available. An open architecture that allows for a variety of solutions is the best way for this to happen.

An open architecture allowing for innovation may best service the electric customer.

Often the price of a system drives behavior that on the initial view is the least expensive but in the long run is less efficient and more expensive. Systems and the components of systems that are inflexible, do not allow for future innovation and potential sharing of costs over multiple products and by multiple industries.

Standards for communications must be developed so that a variety of organizations can access electric and other energy data to provide added value services.

Each component in the overall system must be standards based. Each component must have standard interfaces to promote multiple solutions by hardware and service providers. Just as an energy provider might choose a brand and model of an electric meter, so should they be able to

choose a communications method and provider, a data processor and other components and suppliers.

Innovation at the component level may take place at different rates. Advances in communications capabilities may occur at different times in different locations. Hardware and software development may occur at different rates as well. Standards may allow developments to be incorporated on an ongoing basis. To “freeze” technology would be imprudent. It is better to enable the market to promote innovations on an on-going basis.

Power consumption data is gathered from the metering points at regular time intervals and is delivered to a database. Authorized entities obtain consumption data from this database. The following issues and goals have been identified for further clarification:

- Communications model for database access
- Method of assuring data security
- Format of the data in the database
- Specifications for database access methods
- Desire that the database be distributed, not centralized
- Desire that the communications technology be economical

Some people believe that Client/Server may be the model of choice. The database would reside on Servers. Aggregators, UDC’s and others would access this data with Client applications, on demand. The final decision may have to be made by implementers that have more detailed technical knowledge, though. We expect that security technology, currently being developed for Internet/Intranet commerce, may be usable for this application.

Secure Sockets is one security method for Internet/Intranet messaging that may be appropriate. The goal of distributing the database among multiple servers is important to make the system reliable (redundant) and to achieve adequate levels of performance, as well as to permit multiple vendors to offer this service. The format of the data needs to be developed. The access details may already be developed, if a commercial database package is selected.

8.9.5. Simplifying the Installation of Metering

Meter installation could be easier than it is now, reducing reliance on the UDCs and their established meter shops. Much has been made of the supposed similarities between a meter and a phone, and some have gone so far as to speculate that one day, a consumer may be able to walk into their local hardware store, purchase their meter of choice , take it home and plug it in. While this alternative is unavailable today, and may never be in serious demand, it is conceivable that

parties more sophisticated that the typical residential customer, yet without the UDC's traditional breadth of resources could satisfactorily manage this function at some time in the near future. This section attempts to describe the conditions which market forces must overcome in order to enable this alternative.

8.9.5.1. A Service-Meter Interface Standard Should Be Developed

A new Service-Meter Interface Standard would help ensure the safety and reliability of meter installation, maintenance, and repair operations. By reducing the voltage at the meter socket to no more than 120 volts per phase, safety and ease of installation and maintenance is enhanced and inventories and repair protocols are simplified. By reassigning cost accounting for PTs and CTs from meter equipment to service equipment and keeping the installation and maintenance of CTs and PTs a UDC responsibility, while allowing meter installation to be reconsidered among ESPs, whether the UDC or a competitive provider, competition could be enhanced while mitigating any threats to safety or system security.

8.9.5.2. The "Universal Meter"

To create a retail market in meters and meter installation services similar to the one that telecommunications devices now enjoy, a number of 'standard plugs' similar to the standard two and three prong plug attached to electrical appliances would need to be developed for meters. This would allow the consumer , or more likely, the customer's qualified agent, to plug-in their meter just like a new lamp. A single, truly "universal" plug would not be required, but, like 2-prong plugs for table lamps, grounded plugs for power tools, and 240-volt "power" plugs for electric clothes dryers, a small variety of well-designed combinations could accommodate all likely needs

Two technological changes to the meter and socket would need to occur in order to create the equivalent of a "phone jack" for electricity meters. First, the meter/socket connection must become "one-size-fits-all". Second, a meter socket with a "dead-front" would have to be developed.

8.9.5.3. Current Progress Toward The Development Of A Universal Meter

Legacy Standards

Meters and meter sockets are already standardized. Meter vendors, meter cabinet, and meter switchboard manufacturers presently design their meters and sockets using ANSI C12.10, the accepted industry standard. This standard addresses the internal connections for watt-hour meters. There are approximately 25 different "standard" forms for socket-bases and electric meters (as well as their counter parts for A-base and switchboard mounted meters); the result of each utility developing its own unique specifications over the years. These service configurations

are based on specific customer loads and power equipment requirements which vary in capacity (5 to 4000 amperes), voltage level (120 to 230,000 volts), transformer connection (star or delta), base configurations (socket, A-base, or switchboard), phases (single or polyphase), and even the number of service wires (2-3-4).

Emerging Standards

Limiting the number of electric service configurations available to customers may not pose a major problem. Already, with rare exceptions, utility distribution companies have evolved so that all new customers in the state are connected with one of only six of those 25 standard forms, which arise from three basic circuit configurations (single-phase, three-phase-three-wire, and three-phase-four-wire) and whether the meter connection is direct or though potential and/or current transformers. Currently, meters are connected directly when the voltage is no more than 480 volts and when the current is no more than 320 amperes. Whenever the voltage exceeds 480 volts, potential transformers (PTs) are used to reduce the metered voltage, and 120-volt meters are used. Whenever the line current is over 320 amperes, or whenever PTs are used, current transformers (CTs) are used to reduce the metered current.

A Threshold Universal Standard

No one has recommended that an absolutely “universal” standard plug be developed to fit all meters and services. But, those six standards could be reduced to three, further simplifying inventories for whoever installs meters, and resolving an important safety issue, by the use of transformers whenever the line voltage exceeds 120 volts. That may require some customers to install additional transformersand other distribution equipment, but would then expose a worker to no more voltage than when changing a fuse.

Meter panels could eventually be completely redesigned so that it is absolutely safe for the “lay person” to access them. Current and voltage levels present at the meter/service connection are life threatening if reasonable precautions are not taken, however, and designs for a “dead-front” (energized parts are not accessible) do not currently exist.

Unknown Market

Simplifying the installation of meters by reducing the number of applicable “forms” would not modernize electrical services in any short term. If such a plug existed, it would initially be more attractive to consumers who are constructing new installations and could accommodate the new designs into their plans. . No one has suggested the mandatory retrofitting of a universal meter/plug to existing services nor would that likely be attractive to consumers due to many practical considerations such as meter and socket replacements, space requirements within existing cabinets, time for shutdowns during the conversion, and increased expense. Outlining a “standard” option, however, would provide guidance for a market seeking simplification and de-institutionalization. As in telecommunications, the market may drive the timing of this type of innovation.

8.9.6. Meter Data Collection and the Meter Communications Interface

The alternatives for setting standards where no industry standards prevail center around the desire for "open" standards and are specifically focused on one component of the communications network where an open standard does not currently exist: the Tier 1 link between the meter communications module and the first point of data collection in the communications network.

8.9.6.1. ALTERNATIVE: Establish An Open Standard for Meter Data Collection and the Meter Communications Interface

An open standard is necessary for all meter vendors to be able to interface with a variety of meter data collection and meter data communications systems.

In more specific terms, the data link between individual customers' (interval) meters and the point of data collection or point of communications interface, such as a pole-top receiver, must be governed by the use of an open standard so that any meter vendor who so chooses can employ it without the threat of patent infringement or other legal barriers.

A number of the meter data collection and meter communications suppliers would like to impose on the market the use of closed, proprietary standards for data transfer interface between the meter and the local data collection or communications point. These closed, proprietary standards or protocols are typically used in the lowest tier of the network, the link between the meter and the pole-top receiver of meter data.

By adhering to proprietary standards and failing to move toward a common, open architecture, many of the current metering system vendors are stalling the implementation of widespread use of interval meters. With adherence to closed, proprietary standards for interface between the meter and the data collection or communications point, there is greater risk of choosing the wrong horse (technology) and being saddled with it for a long time. Consequently, California may be delayed in gaining the competitive and social advantages of widespread access to competitive power markets. Moreover, the dispersion of benefits from Direct Access may be limited to large customers, to the detriment of small and intermediate sized customers. Otherwise, the potential is great to be saddled with a single system for metering and data collection. This would allow for the development of monopolies in metering and all the attendant problems of monopoly behavior, such as the intentional slowing of new technology adoption.

Alternative 8.9.6.1. PRO:

1. Suppliers may be able to develop interchangeable products at lower risk.

2. Consumers are less likely to select a technology that may become obsolete.

3. A greater number of consumers are more likely to receive benefits from Direct Access.

4. Competition for metering and data communications is more likely.

5. New product innovation is more likely.

Alternative 8.9.6.1. CON:

1. There is no open standard to select. This makes it somewhat difficult to accrue any of the potential advantages.

2. Selection or designation of an existing proprietary standard for use in California may arbitrarily result in significant short-term advantage for the supplier whose standard is selected, to the detriment of other market players.

3. Selection or designation of an existing open standard that is not currently used by any supplier may cause years of delay in gaining the competitive and social advantages of widespread access to competitive power markets as all suppliers of these products retool and redevelop their operations and product lines.

4. There is no guarantee that the suppliers may elect to develop products under your selected standard to begin with.

5. Technology obsolescence may occur whether there is an open standard or not.

8.9.6.2. ALTERNATIVE: Allow the Existing Competitive Marketplace to Determine What the Open Standard for the Meter-Telemetry Interface Should Be

Competitive businesses take business risks, that is part of what competition means. It is counter-intuitive (and potentially impossible) to attempt to regulate an already competitive market (in meters and communications) in order to reduce the risk to an emerging market in retail energy and generation services. ESPs who want to do business may manage to do so quite well without the interference of regulation, as they have continually made clear during this proceeding.

Every major meter manufacturer currently performs factory-installation (at very low cost) for the meter communications modules of every major meter communications network supplier, permitting competition on the meter communications business to develop.

Furthermore, many value-added retailers have Memorandum's of Understanding with each communications network supplier to develop connections for advanced communications that interact at the top of the Tier 1 collection point (the pole-top collector, for example) which typically does communicate with everything but the meter under an open standard.

The market for networks to perform these activities is still relatively young and no clear standard has emerged at the lowest tier. The most appropriate action for the Commission to adopt is to

allow this market to continue to develop naturally and allow the industry standard to emerge as the result of competitive forces.

Alternative 8.9.6.2. PRO:

1. California (overall) may have less risk of “picking the wrong horse”.

2. Multiple suppliers and technologies continue to have the opportunity to compete for market share.

3. Lowest cost/highest function may ultimately result in more consumers able to benefit from the retail electricity market.

4. New product innovation is not constrained by the lack of a Tier 1 standard.

Alternative 8.9.6.2. CON:

1. Some technology obsolescence may eventually result.

2. Market players interested in deploying large systems may undertake additional risk until the standard emerges.

3. New product innovation may proceed more slowly in the short-term.

4. The risk of being stuck with the wrong technology may persuade market participants to do nothing at all.

8.9.7. A Process to Adopt Additional Necessary Standards

This section provides a process and schedule for the development of required standards for electric metering and data communications that all electric energy service providers may be required to comply with. Meter data recording and collection requirements may be as specified in Section 8.2 of this report.

8.9.7.1. Areas Where Standards are Needed

Metering and data communications systems standards are needed to ensure that requirements are met in the following areas:

- Compatibility of equipment and systems provided by different entities

- Integrity of metering and data communications - the system works as desired

- Development of Licensing/Certification requirements

- Enforcement of adopted standards
- Security of meter data
- Unauthorized Access
- Theft Prevention/Deterrence of Tampering
- Timeliness of meter data delivery/access
- Safety—both public and employee
- Accuracy of metering systems -- initial and ongoing

Adoption or development of standards could be considered for the following categories:

Performance of Work:

- Metering equipment operations
- Metering equipment installation
- Metering equipment maintenance
- Metering equipment testing - procedures and frequency
- Licensing of metering installers
- Coordination with local electrical inspection authorities
- Meter vendor certification

Hardware and Software

- Meter communications protocols
- Meter reading systems
- System integration
- Data storage
- Data access
- Data transfer systems and protocols

- Meter programming systems and protocols

8.9.7.2. Standards Implementation Process

The Commission should determine the need, if any, for standards that do not presently exist in the electric industry. For those areas where standards do not exist, and the Commission feels a standard is necessary to create or promote competition in metering technology or services, the Working Group has developed a possible process. The Commission should recommend from among existing standards whenever feasible and sponsor an Electric Metering and Communications Standards Working Group to develop any remaining standards. The Working Group should be specifically directed to develop proposed standards to be submitted to ANSI for formal adoption and review. Such a Working Group could include representatives from such groups as the investor owned utilities; Commission staff; metering, service entrance equipment, and communications suppliers; Electric Services companies (including retailers, aggregators, etc.); consumer group representatives; and other interested parties.

8.9.7.3. Proposed Schedule for Metering Standards

The Working Group should start work immediately on those items that are not dependent on the results of the Ratesetting Working Group. The target date for those standards should be December 31, 1996. Additional work may be scheduled following a decision on Ratesetting and dependent on standards deemed necessary for the 1/1/98 implementation of Direct Access.

8.9.7.4. Adherence to Standards Over Time

Once standards are in place, they may need to be maintained, communicated and updated as technology and accepted industry practice changes. Ongoing certification and compliance monitoring may also be required.

8.9.7.5. Certification of Compliance of Equipment with Standards

Utilities, Manufacturers, or independent testing laboratories may certify and approve new technology (meters for example) for compliance with applicable standards.

Timelines are critical. If there were an independent lab that could do this for distribution companies, then it would not make sense for a single meter to undergo a certification in each utility's service area. We need centralized and independent certification authority for all of California.

Entities with established qualifications, such as UDCs, testing laboratories, engineers, electrical contractors, etc., could be authorized to access equipment (like metering) which is part of the utility distribution system.

It would be grossly inefficient and costly for a new meter to be certified by multiple UDCs throughout California. One, independent certification agency should be designated. Once certified as complying with minimum California standards it would require no further approvals. If UDCs are permitted to be the authorized certification authority they, or their affiliates, cannot own an interest in any of the candidate companies or technologies.

8.9.7.6. ALTERNATIVE: UDCs Not to Certify Technology of Competitors

Certification and approval of new technology, and control over the qualification and certification of companies and/or individuals permitted to access metering and data communication equipment should not be left to the UDCs. To do so could quell competition and provide an opportunity for UDCs to engage in anticompetitive conduct. An independent third party should be given this task once standards have been adopted. Any number of third parties might fill this role: ANSI, Underwriters Laboratory, the Federal Communications Commission, or a division established by the CPUC.

Alternative 8.9.7.6. PRO:

1. Could spur technological innovation.
2. Does not provide an opportunity for anti-competitive UDC conduct.

Alternative 8.9.7.6. CON:

1. The independent third party must be recruited or established and trained, creating delay and costs.
2. Could affect reliability of the system.

8.9.8. Regulatory Monitoring

8.9.8.1. ALTERNATIVE: Different Regulatory Monitoring Standards for Different Entities

The Commission should continue to have full and ready access to any pertinent data kept by IOUs/UDCs. The Commission should exercise more limited access to data kept by Retailers, perhaps just metering and billing practices. No explicit PRO or CON arguments were provided by any parties for this position.

8.9.8.2. ALTERNATIVE: Regulatory Monitoring Access Should Be Consistent For Both UDC And Retailers.

Methods and procedures for monitoring and enforcement of standards need to be defined and established, to ensure ongoing compliance by all parties. Some standards may be enforced by governmental agencies, such as local electrical inspectors and the Commission. Some standards may be enforced by the UDC, such as inspection, verification and testing of meter installations . Enforcement, especially when an unsafe condition exists, should be at the discretion of the utility

and may consist of requiring that an installation that is not in compliance be corrected, with service disconnection or refusal of service connection as the ultimate enforcement mechanism. No explicit PRO or CON arguments were provided by any parties for this position.

Chapter 9. Billing

This chapter outlines alternative solutions to issues surrounding the distribution and collection of customer energy service bills. While D.95-12-063 assigns billing to the UDC as one of several component services within the distribution function, private energy service providers (ESP) will clearly need to be compensated for the services rendered -- normally meaning that a bill is submitted to the customer and customer payments are processed. Aggregators, and marketers serving the bilateral contract market, perceive that "duplication" in billing services creates problems, which they generally would like to resolve by unbundling billing services from the UDC. While D.96-03-022 created a process that assigns responsibility for this issue to the Ratesetting Working Group, its importance to direct access providers motivates much discussion in the DAWG process.

Most of the DAWG's discussion centered on which entity or entities would provide billing services for the end user -- the UDC, the energy retailer, a third party or some combination of these. The other major question running through the billing discussion was what happens if the retailer is responsible for billing and does not pay the UDC. Is the end user ultimately responsible after all means of payment from security have been exhausted? What if the end user can prove it paid the retailer for the UDC's services? Bill format questions were briefly discussed, with parties split between advocates of standardization statewide and those who believed the end user would be better and more creatively served by fewer limits on billing means.

Four sections are included in this chapter. Section 9.1 issues of who sends a bill to the end user. Section 9.2 discusses responsibility for payment. Section 9.3 discusses bill format and standardization. Section 9.4 briefly raises concerns about customer contact.

9.1 Alternatives for Bill Presentation

Once direct access is implemented and there are multiple service providers to a single customer, there must be an answer to the question of who provides the billing for that customer's energy services. Three possible alternatives and a couple variants to those alternatives have been presented by various parties, which in turn present different issues of CPUC oversight. The following three alternatives can either be viewed as unique (only one statewide solution) or as a menu of options. Some parties believe the menu approach best meets the need to offer customer choice, while others advocate a consistent statewide approach. (These alternatives also are discussed in section 4.2.2.4 in terms of how these different billing options impact phase-in of direct access.)

The first alternative is essentially the status quo -- the UDC would provide a single bill for all charges, including those from the energy retailer and any other service providers. The second

alternative is for a third party to provide such bundled billing. Most discussion within the Working Group was of the energy retailer serving that function, but there were suggestions that it could be done by a third party billing agent who does nothing for the end user except provide the billing service. Finally, the end user could receive bills from both the UDC and the energy retailer. That alternative leaves available the option for one of those entities to contract with the other to provide bundled billing.

9.1.1 ALTERNATIVE: UDC Bundled Billing

The UDC shall, on a monthly basis, dispense a single bill to each of its direct access customers. That bill shall include a breakdown of all generation, transmission, distribution, CTC, Public Goods and other applicable charges attributed to that customer over the past month. The direct access customer's retailer shall expeditiously give all requisite supply information to the representative UDC, so that the customer's entire bill may be calculated and dispensed in a timely fashion.

Alternative 9.1.1 PRO:

1. Some believe this is the simplest solution. Since the direct access customer is still a customer of the UDC for wires services, the UDC would simply continue billing for services it supplies to the customer and add to that any additional services provided to the customer by the market. There will be few problems with the UDC distribution function, CTC and PGC revenue collections.

2. UDC charges are likely to constitute the majority of the customer's bill, at least during the industry's "transition period" (1998-2005), so it may be appropriate that the UDC continue to maintain control of billing for its services.

3. The UDC billing system infrastructures must be able to bill for virtual direct access and may be better positioned to accommodate billing third party services to other direct access customers given the proposed phase-in schedule of the Commission. The competitive market may not be able or willing to systematically bill all direct access customers for all energy services on January 1, 1998.

4. The UDC presently has responsibility for providing its customers with certain legal notice of regulatory events, service options and rule reform. This requirement is often accomplished by inserts in a customer's bill.

5. A direct access customer can change suppliers or aggregators consistent with the terms of supply contract and "switching" standards established by industry market rules. There may be a greater potential that a customer's bill will be properly handled during this switching process if a single agency, the UDC, perpetually bills the customer. If an aggregator no longer provides its services to an individual, it may be problematic for another aggregator rather than the UDC to

assume that role and bill the customer correctly since the customer records already reside at the UDC.

6. This could reduce costs for retailers because they don't have to develop billing systems capable of billing all energy services.

7. Consumers have only one statement to open, read and pay.

8. Consumers see their whole electricity bill at once, giving them a better idea of what their use of energy is costing them and how their overall costs change over time.

9. The total cost of billing is lower because no duplicate billing is done.

Alternative 9.1.1 CON:

1. UDC bundled billing may preclude retailers from entering the restructured electric service marketplace. They have indicated that, at minimum, the CPUC must establish a rigid schedule of what monopoly services will be unbundled and when to assure utility compliance.

2. The customer is denied a choice of provider for billing.

3. Depending on the Commission's decision regarding the timing and degree of unbundling, customers may lose an opportunity to have certain electric services repackaged to accommodate their particular needs at the lowest cost.

4. If the UDC provides a bundled bill to the direct access customer, retailers may lose brand name recognition for the services that they provide. This may inhibit market penetration.

5. When there are multiple service providers there could be an issue of financial float. Depending on the rules and details, some parties may benefit or be harmed.

6. This could increase cost to the UDC if there is a need to modify systems to do retail billing and the UDC is not compensated by retailers for incremental costs.

7. UDC billing systems presently are not capable of billing large numbers of direct access customers.

8. Uniform CPUC proscribed billing forms and format would not be customized according to customer needs.

9. The decrease in the cost of third party supplier billings would be minimal. Third party billers would still have to calculate the amount owed for the service provided as well as associated

transmission based fees such as the Public Goods Surcharge, maintain those records and perform other related tasks or pay the utility a market rate to perform these functions.

10. Retailers should be allowed to maintain their right to bill their customers, a right afforded other businesses.

11. The UDC may incur risks for third party charges it may not wish, or be able to handle within existing ratemaking treatment.

12. There may be confusion for the customers on whom to call when they have questions about their bills.

9.1.2 ALTERNATIVE: Retailer/Third Party Billing Agent Bundled Billing

The retailer may, on a periodic basis, dispense a single bill to each of its direct access customers. Some believe this periodic basis must be monthly, while others believe other options may evolve through the marketplace. That bill would include a cost breakdown of all generation, transmission, distribution, CTC, Public Goods and other charges attributed to that customer over the past billing period. The transmission charges will be provided by the ISO (and perhaps, in part, the UDC); the distribution charges, CTC and public goods charges will be provided by the UDC; charges for generation and other services supplied by all retailers will be provided by those entities. A variant on this alternative is the use of a third party billing agent who provides no other services.

Alternative 9.1.2 PRO:

1. If retailer is the biller, it would be better able to gain name recognition and perhaps increase the speed of market penetration.

2. Retailers may be better able to enter the market.

3. Retailer or billing agent billing may lead to quicker innovation and services.

4. Customers can get electric services packaged to accommodate their particular needs.

5. Consumers have only one statement to open, read and pay.

6. Consumers see their whole electricity bill at once, giving them a better idea of what their use of energy is costing them and how their overall costs change over time.

7. The total cost of billing is lower because no duplicate billing is done.

8. Services may be better tailored to customer needs than tariffed UDC services.

Alternative 9.1.2. CON:

1. The customer is prevented from making its own selection of who it would like to bill its services.

2. In repackaging or rebundling of services, there's an opportunity for retailers to keep savings the customers would otherwise see from restructuring.

3. The UDC would be dependent on third parties to collect a large bulk of its revenues.

4. The creditworthiness of retailers could be a serious concern.

5. Consumer would have no UDC verification that the distribution services billed by the UDC and those billed by the retailer correlated to each other.

6. Consumer notification of regulatory events, service options, information-only statements of UDC charges and mandatory notices may become more complicated.

7. Expected savings by the UDC from third-party billing may be small. Incremental decreases of specific unbundled components to a UDC billing transaction don't correlate to an equal incremental decrease in its billing costs.

8. Some customers will aggregate their own loads. If aggregators are to be charged with the billing function, these customers would be charged with calculating their own bills. There may be self-dealing concerns depending on which services are finally unbundled.

9. Concerns over customer "disconnect" policies for non-payment may become more complicated.

10. When there are multiple service providers there could be an issue of financial float. Depending on the rules and details, some parties may benefit or be harmed.

11. UDCs and retailers should be allowed to maintain their right to bill their customers, a right afforded other businesses.

12. Potential loss of scale economies and postage discounts could render third party billing uneconomic compared to other alternatives.

13. There may be confusion for the customers on whom to call when they have questions about their bills.

14. A third party presentation of a bill to a customer does not eliminate the UDC's need to calculate the bill and its components as well as perform other billing-related tasks. Accordingly, any savings generated by a third party bill presentation would be minuscule at best.

9.1.3 ALTERNATIVE: Split Billing Options

In this alternative, the customer would receive two bills. This option assumes that the retailer is also a third party biller. The UDC would bill the customer for the distribution services, CTC, PGC, etc. that it provides the customer, and the retailer would bill the customer for the services that it provides.

This option leaves the choice of whether retailers will joint bill in UDC billing envelopes (or vice-versa) and the terms of such joint billing, to the market participants as a commercial transaction. The CPUC would intervene only if necessary should abusive practices emerge.

Alternative 9.1.3 PRO:

1. The retailer would receive brand name recognition from its bill.

2. The UDC would better control the collection of the revenues required to achieve lower costs for its core customers and assist a positive transition into a competitive marketplace.

3. The customer would be able to verify the consistency of the energy supplied to it against the energy delivered for it.

4. This may provide for greater clarity for the consumers on whom to call when they have questions about their bills.

5. Consumer protection issues would be more easily managed. Legal notification and customer education process would remain with UDC, and self dealing concerns would be minimized.

6. This may provide for relatively greater simplicity in implementation.

Alternative 9.1.3 CON:

1. Some customers may prefer a single bill rather than two bills.

2. Retailers would not be given an opportunity to repackage soon-to-be unregulated electric services with traditional UDC distribution service.

3. The customer is prevented from selecting who bills for services.

4. Customer disconnect policies for “non-payment” may become more complicated.

5. Customers may need to contact both the UDC and energy service providers with billing inquiries.

6. A split bill may be too expensive for the small customer market, thereby precluding entry by new providers because providers (particularly smaller ones) must acquire billing, payment and receivables capability and will experience increased costs and may find it a barrier to entry.

7. Consumers cannot compare total costs, on an average daily cost basis, between competing suppliers.

8. UDCs and providers both bear costs for billing common customers (and consumers pay).

9.2 Payment of Bills

Payment issues will become more complex in a direct access environment as at least one third party (and perhaps more if multiple retailers are used) is added to the mix of relationships, to what previously was limited to the end user and the IOU. Most of the issues discussed concerning payment of bills arose while considering the second alternative discussed above, where the retailer is responsible for passing on payments to the UDC. The most discussed issue was the end user's responsibility if it pays UDC charges to its retailer but the retailer does not in turn pay the UDC.

9.2.1 Responsibility for Paying UDC Charges

Even with the advent of direct access the end user will continue to receive service(s) from the UDC. Is the end user or the retailer responsible for paying charges to the UDC? This issue encompasses whether the retailer or end user will pay UDC charges to the UDC and, if the UDC sends a bill to the retailer who provides a bundled billing service, whether the UDC may seek payment from the end user if the retailer fails to pay. The discussion below also concerns the situation where another third party -- whether a neutral billing agent or another retailer -- provides billing services to both the UDC and retailer.

9.2.1.1 ALTERNATIVE: End User Responsible in End

The end user continues to be responsible for UDC charges, even if the UDC sends the bill for those charges to a retailer. However, where there is a retailer, the UDC will look first to the retailer for payment. Only in the event that the retailer fails to pay UDC charges, and only if

security for those charges is inadequate to cover them, will the UDC look, as a last resort, to the end user for payment.

Alternative 9.2.1.1 PRO:

1. Other UDC customers should not have to bear these costs, nor should the UDC..

2. The retailer would be able to provide a value-added service to the end-user and UDC by providing bill collection services.

3. This is consistent with current rules for gas core aggregation.

4. This alternative promotes development of a relationship between retailers and end users, thereby facilitating quicker development of a competitive market.

5. The retailer will be certified by the CPUC, and thus will have met certain financial and creditworthiness criteria. Payment to UDCs will be more reliable and timely than by end users. Additionally, the UDC will have a smaller universe of customers from whom to collect, thereby reducing administrative and other costs.

Alternative 9.2.1.1 CON:

1. The end-use customer is still potentially liable for payment(s) to the UDC, other energy service providers and local governmental entities if the retailer is unable or refuses to satisfy the end-user's outstanding obligations. The end-use customer would have to pay the UDC and others and pursue recovery from the retailer.

2. The customer bears the risk that the retailer will not perform obligations to the UDC.

3. Some customers may not understand the ramifications of a retailer's failure to pay amounts owed to the UDC.

9.2.1.2 ALTERNATIVE: End User Not Responsible if It Paid Charges

This variant agrees with the principle alternative, except as follows: the UDC may not pursue for payment an end user who can demonstrate that it has already paid the UDC charges in question. In circumstances where an unscrupulous or financially unsound retailer has collected such payments from an end user but not forwarded them to the UDC, an end user should not have to "pay twice." The risks of such conduct by retailers is better spread across the entire UDC customer base than left to fall on single innocent end users.

Alternative 9.2.1.2 PRO:

1. The risk is spread across a large base.

2. Innocent end users do not suffer at the hands of unscrupulous or financially unsound retailers.

Alternative 9.2.1.2 CON:

1. Other innocent end users bear the cost of spreading the risk.

2. An efficient and neutral mechanism to allow innocent end users to prove that they have paid their UDC charges must be established, with an attendant financial cost.

9.2.2 Security To Ensure Bill Payment

Where the UDC (or another service provider) is dependent on a retailer or third party billing agent to pay its charges, the question arises as to whether it may require the retailer to post payment of the charges owed to it and, if so, what that security will be. For default service customers the UDC presumably will require security from customers and will impose credit rules on end-users consistent with current rules. If an end-user receives service from a retailer which does all billing, security could be addressed in a couple of ways: (1) the UDC could impose a creditworthiness requirement on retailers or require a security deposit from retailers; or (2) a statewide insurance risk pool managed by investment bankers could provide payment in case of default.

9.2.2.1 ALTERNATIVE: UDC-Imposed Creditworthiness Requirement of Retailers

Consistent with natural gas rules on transportation, the UDC could impose a creditworthiness requirement on retailers and make the final determination of the retailer's creditworthiness. In lieu of this requirement, retailers could submit a security deposit, using the various forms of security described in gas core aggregation rules, including letters of credit, cash deposit, or surety bond. Such forms of security should have standardized terms and conditions to avoid arbitrary UDC action. The security amount would be a function of UDC charges collected by retailers (for example, 90 days estimated bill). The UDC and other suppliers could pursue further collection from the end-use customer in scenarios where the obligation incurred by the retailer on behalf of the customer exceeds the security deposit.

Alternative 9.2.2.1 PRO:

1. UDC and other service providers are partially or wholly protected by the security deposit.

2. The end-use customers and retailer would retain current legal protection through the bankruptcy process.

3. Creditworthiness/security deposit requirements on retailers would help to ensure that retailers in the market are credible players.

Alternative 9.2.2.1 CON:

1. End-use customer may be assuming an unknown amount of liability through transactions conducted by the retailer (i.e. unsuccessful attempts to “game” the system).

2. A security deposit would impose a burden upon the retailer or its end-use customers. Smaller retailers may find posting security onerous.

3. Security requirements can create added costs, which need to be minimized in order to avoid impediments to competition.

9.2.2.2 ALTERNATIVE: Statewide Insurance Risk Pool Managed by Investment Bankers

An alternative to retailers providing security directly would have competitive investment bankers manage an insurance risk pool on a statewide basis. The pool would provide payment to UDCs in the event of a member's default. The risk manager would determine the charges that would be necessary for membership. Such a pool might be optional, rather than mandatory, and customers could choose to transact with retailers who are members of the pool, thereby no longer being responsible to the UDC for retailer non-payments, or the customer could transact with non-members and remain liable to the utility in the event of retailer non-payment.

Alternative 9.2.2.2 PRO:

1. Standardized security terms could insure that all retailers could participate if they want to and are financially capable.

2. Reduces short-term financial liability for UDC and end-use customers from new market entrants.

3. Security protects both consumers and the UDC from non-performing retailers.

4. Providing several options allows the market participants to determine which means to protect consumers and the UDC from nonpayment is most effective and desirable.

5. Insurance "pool" helps to allocate equitably the cost of the risk of non-performance and allows the market to price this risk.

Alternative 9.2.2.2 CON:

1. Offering the customer the choice to transact with retailers who are members of the insurance risk pool or non-members is potentially confusing.

2. If the pool is not mandatory, the UDC must be able to look to the end-use customer if the pool goes bankrupt.

3. If the pool is not mandatory, adverse selection may occur. Even if the pool is mandatory, it creates the opportunity for cross-subsidies among pool members, which may confer an inappropriate financial advantage to financially irresponsible firms.

4. This approach implies UDC acceptance of a risk pool as sufficient security, which may not provide adequate coverage for all activity of a retailer with every UDC statewide. Adequacy of coverage cannot be assessed based on one retailer's activity with an individual UDC.

5. UDCs have current credit rules that adequately address issues for retailers in the wholesale gas market. These can be easily adapted to the electric market.

9.2.3 Obligation to Pay and Change of Service

The issue is whether an end user can change service without having reconciled payment obligations under the previous service. Only one alternative was presented.

9.2.3.1 ALTERNATIVE: Current CPUC Rules, Contract Terms for Retailer

For end-users taking default service who seek to change to a retailer, the UDC will apply current payment rules, including shut-off alternatives to ensure payment of charges owed to it.

For end users taking service from a retailer who desires to switch to default service, the UDC will apply its current credit rules. If the end user has failed to pay its bill to a retailer, this may affect the UDC's application of its credit rules.

The ability of an end user to switch from service by a retailer and the end user's payment obligations will depend on the commercial terms of the end user/retailer contract.

Alternative 9.2.3.1 PRO:

1. Ensures fulfillment of obligations.

2. Minimizes CPUC regulation.

3. Inhibits gaming of the system.

Alternative 9.2.3.1 CON:

1. End-users who have failed to make full payment to a previous retailer should not be distinguished by the UDC from other customers. The retailer who has not been paid has a number of available remedies, but it should not be allowed to pursue the threat of preventing a customer from getting service from another retailer or creating obstacles for getting service from the UDC.

9.2.4 Billing Disputes and Payment Obligation During Pendency of Dispute

Direct access makes billing disputes more complicated, as the addition of parties creates several different possible arenas for dispute. While the dispute is going on in one part of the billing chain, payments will be due at other parts.

9.2.4.1 End User/UDC Disputes

Again, the main issue is under what circumstances the end user remains liable to the UDC where the retailer in an intervening bill collector. The alternatives presented turned on whether the end user remains responsible during billing disputes where it can prove it already paid.

9.2.4.1.1. ALTERNATIVE: Retailer Must Pay and End User Responsible in End

If the end user disputes the bill of the UDC, the end user may take the matter up with its retailer. The retailer can raise the issue with the UDC. During the pendency of the dispute the retailer must continue to pay the UDC's charges, consistent with current CPUC billing rules. Whether the end user is obligated to pay its charges to the retailer will depend on the commercial contract terms between the end user and the retailer. If the retailer fails to pay the UDC charges, even in the event of a dispute, the UDC could go after security and if security is insufficient then seek payment from the end user, with possible termination of service if charges remain unpaid.

Alternative 9.2.4.1.1 PRO:

1. Continues existing policies and protections for bill disputes involving utility charges.

2. Allows the retailer to offer services as the end user’s representative in addressing bill disputes.

3. The end-use customer retains the right to use the CPUC complaint process.

Alternative 9.2.4.1.1 CON:

1. Some customers may not feel comfortable looking to the retailer for bill dispute protections (although they are not obligated to do so).

2. The retailer is still responsible to pay the UDC charges while the dispute between the retailer and customer is being resolved.

9.2.4.1.2. ALTERNATIVE: Retailer Must Pay but End-User Only Responsible if It Did Not Pay

The only variation under this alternative is that the end user would not be required to pay previous UDC charges it had already paid, upon proof of such payment. The end user could be required to pay current and future UDC charges during the pendency of the dispute, however.

Alternative 9.2.4.1.2 PRO:

1. The risk is spread across a large base.

2. Innocent end users do not suffer at the hands of unscrupulous or financially unsound retailers.

Alternative 9.2.4.1.2 CON:

1. Other innocent end users bear the cost of spreading the risk.

2. An efficient and neutral mechanism to allow innocent end users to prove that they have paid their UDC charges must be established, with an attendant financial cost.

9.2.4.2 End User/Retailer Disputes

If there is a billing dispute by an end user relating to the bill of a retailer, what are the end user's obligations to pay the bill during the pendency of the dispute and what happens if the end user does not meet this obligation?

ALTERNATIVE: Contract Terms Determinative

The end user's options in the event of a billing dispute with the retailer will depend on the commercial terms of the contract between the end-user customer and the retailer.

Alternative 9.2.4.2.1 PRO:

1. Avoids regulation of competitively-provided services.

2. Permits flexibility in commercial contract terms.

Alternative 9.2.4.2.1 CON:

1. Terms of the commercial contract between end-use customer and retailer will not be determinative where the contract violates basic rules established by the CPUC.

9.2.4.3 Retailer/UDC Disputes

If there is a billing dispute by a retailer relating to the bill of the UDC, what is the retailer's obligations to pay the bill during the pendency of the dispute and what happens if the retailer fails to meet this obligation? Only one alternative was presented.

9.2.4.3.1 ALTERNATIVE: Current CPUC Rules Apply

In the event of a billing dispute, the retailer must pay the UDC's charges in accordance with current CPUC rules.

Alternative 9.2.4.3.1 PRO:

1. Continues existing policies and protections for bill disputes involving utility charges.

Alternative 9.2.4.3.1 CON:

1. Present rules may be insufficient to protect UDC from certain billing disputes.

9.2.5 Termination of Service

Termination of service can arise in two contexts: termination of service that is sought by the supplier (UDC or retailer), or termination that is sought by the end user. The former is addressed in this section. The latter subject is addressed in Chapter 5.

9.2.5.1. UDC Terminating Service to Retailer

The issue here is whether if a retailer fails to pay charges it owes to the UDC, the UDC may terminate its commercial relationship with the retailer, and, if so, what happens to continuing service to the end user served by that retailer.

9.2.5.1.1 ALTERNATIVE: End User Responsible in the End

If a retailer fails to pay UDC charges, the UDC will seek recovery from the retailer, call on security, if any, and, if necessary, from the end user. In the event the end user fails to pay, the UDC could terminate service consistent with CPUC rules. Retailers who consistently fail to pay bills should be subject to license revocation or decertification. If a retailer loses its license or is decertified, end users transacting with a retailer will be given the option to take service from another retailer or take default service.

Alternative 9.2.5.1.1 PRO:

1. Consistent with current CPUC rules.

2. Encourages responsible retailers.

Alternative 9.2.5.1.1 CON:

1. Some customers may be unwilling to bear the risk of retailer non-performance.

2. Current CPUC rules may be inappropriate for the competitive environment.

3. Current rules under the natural gas core aggregation program provide for UDC termination of service to a retailer for non-payment after seven days notice. UDCs should not be forced to subsidize retailers for nay length of time by continuing to give them access to the UDC distribution system without compensation. Additionally, users should not be subject to haphazard business practices of retailers who fail to pay their bills. Accordingly, UDCs should have the right to immediately terminate a retailer who fails to pay a bill and the CPUC should also decertify that retailer.

9.2.5.1.2 ALTERNATIVE: End User Not Responsible If It Paid Charges

If a retailer fails to pay UDC charges, the UDC will seek recovery from the retailer, call on security, if any, and, if necessary, seek recovery from the end user. In the event the end user fails to pay, the UDC could terminate service consistent with CPUC rules, unless the end user proves that it has already paid the UDC charges to the retailer, who has failed to in turn pay them to the UDC. Termination of an end user in such circumstances would be prohibited. Retailers who consistently fail to pay bills should be subject to license revocation or decertification. If a retailer loses its license or is decertified, end users transacting with a retailer will be given the option to take service from another retailer or take default service.

Alternative 9.2.5.1.2 PRO:

1. The risk is spread across a large base.

2. Innocent end users do not suffer at the hands of unscrupulous or financially unsound retailers.

Alternative 9.2.5.1.2 CON:

1. Other innocent end users bear the cost of spreading the risk.

2. An efficient and neutral mechanism to allow innocent end users to prove that they have paid their UDC charges must be established, with an attendant financial cost.

9.2.5.2 UDC Terminating Service to End User

The next issue is whether the UDC can terminate physical service to an end user if the end user fails to pay charges owed to a retailer or the UDC. Only one alternative was proposed.

9.2.5.2.1 ALTERNATIVE: Current CPUC Rules Apply

The UDC will not terminate delivery service if an end user fails to pay charges owed to a retailer, so long as the UDC continues to receive money owed to it. If the UDC does not receive payment of charges owed to the UDC, it may terminate service consistent with current CPUC rules.

Alternative 9.2.5.2.1 PRO:

1. Prevents retailers from using shut-off threats to unreasonably leverage end users.

2. Retains shutoff rules within CPUC jurisdiction.

3. Consistent with current CPUC rules.

4. Consistent with gas core aggregation rules.

5. Encourages transacting with responsible retailers.

Alternative 9.2.5.2.1 CON:

1. Some customers may be unwilling to bear the risk of retailer non-performance.

2. May keep retailers out of the market if the UDC continues to bill the customer for distribution. Retailers, as non-monopoly providers, are not bound by non-discriminatory service obligations. Requiring them to be, when they are only providing a competitive commodity, imposes obligations and risks that could prevent them from entering the market.

3. Current CPUC rules may be inappropriate for the competitive environment.

9.2.5.3 Retailer Termination Policy

The third termination issue concerns whether a retailer can physically terminate service to an end user if the end user defaults on charges owed to the retailer. Again, only alternative was proposed.

9.2.5.3.1 ALTERNATIVE: Service Will Not be Terminated

Retailers have no ability to physically terminate service, and the UDC will not terminate physical connection on demand of a retailer. If a retailer terminates its service contract, the end user will have the option of choosing another retailer or taking default service. See Chapter 5 - Notice Provisions.

If electricity is a commodity obtained in a competitive market, it is not unreasonable to expect retailers to minimize bad debt. There should be a mechanism established whereby retailers work with bad debt customers to determine whether the cause of non-payment is related to a problem with the retailer, or whether the customer needs a lifeline rate. If not, the retailer should be able to notify the UDC that the customer is in arrears and the retailer will no longer be serving that customer.

Alternative 9.2.5.3.1 PRO:

1. Prevents retailers from using shut-off threats to unreasonably leverage end users.

2. Retains shut-off rules within CPUC jurisdiction.

3. Prevents UDC from being in position of arbitrator of disputes between retailers and end users.

Alternative 9.2.5.3.1 CON:

1. If an efficient mechanism is not in place to ensure payment of charges there will be additional costs to providing service in competition with the UDC.

9.2.6 Time Limit Standards

There was little discussion within the Direct Access Working Group of time requirements for the payment of bills. The only proposal presented concerning UDC bills is that: payment terms for retailer payments to the UDC should be standard and consistent with current UDC payments requirements for commercial customers (already approved by the CPUC).

The only proposal presented concerning retailer bills is that: the payment terms for retailer bills need not be standard and should be determined by the retailer and the end user. It is argued that this

position maximizes flexibility and customer choice in commercial transactions in a competitive market and that this is consistent with business practices in other industries.

The only proposal presented concerning late payment charges is that: payment terms, including late payment charges imposed by UDCs on retailers should be consistent with current payment terms for commercial customers. Whether retailers impose late payment charges on end users should be determined by the retailer and the end user. Again, it is argued that this position maximizes flexibility and customer choice in commercial transactions in a competitive market and is consistent with business practices in other industries. The only counter to this position has been the argument that there should be no late payment charges for small customers so long as the UDC can continue to impose meter deposits upon customers. If the meter deposit rule is rescinded, then late payment charges might be appropriate.

9.3 Bill Form and Format Standards

9.3.1 Standardization of Billing Practices

The first standards issue is whether there should there be standardization of billing *practices*. Examples of billing practices include late payment charge amounts, baseline allowances, collection charges, days until late payment charge is imposed, etc. Only one alternative was proposed.

9.3.1.1 ALTERNATIVE: No Billing Practices Requirements

No requirements for billing practices should be imposed on retailers. Standardizing billing practices among the state's UDCs may be helpful to retailers and should be explored further, but are not essential to facilitate a competitive retailing market.

Alternative 9.3.1.1 PRO:

1. Avoids misdirecting resources away from crucial unbundling and other direct access issues.

Alternative 9.3.1.1 CON:

1. Moving away from multiple practices may be helpful to retailing efforts.

2. No standardization of billing practices could create more customer confusion.

9.3.2 Standardization of Billing Procedures

The next standards issue is whether there should be standardization of billing *procedures*. Examples of billing procedures include changing retailers, security requirements, and notices to end users. Billing procedures including security and notices between retailers and end users should not be regulated. Only one alternative was proposed.

9.3.2.1 ALTERNATIVE: Some Common Procedures Necessary

For UDC billing and sign-ups for end user connection, some generally applicable procedures need to be developed. There should be some data protocol standards to provide for the timely and efficient exchange of information among those with a need for the information (e.g. UDCs, retailers, end users). There needs to be some common standards for enrollment and termination with a retailer, including written customer authorization and reasonable time frames to process requests to change retailers.

Alternative 9.3.2.1 PRO:

1. Standardizing procedures, where appropriate, will help end users, retailers, and UDCs ensure continuity of service and facilitate necessary exchange of information.

Alternative 9.3.2.1 CON:

1. Standardizing procedures may be complex.

9.3.3 Standardization of Bill Format

The third standards issue is whether there should be any standardization of *format* for bills provided by the UDC or retailers, and, if so, what is the nature and scope of the standardization.

9.3.3.1 ALTERNATIVE: No Standardization of Format Required

No statewide standard for UDC bill formats to retailers or end-users is necessary or appropriate. No regulation of retailer bill format to end users is necessary or appropriate, except to provide end users with clear information on who to call with questions and information on redress and to comply with legal or regulatory disclosure requirements.

UDCs should make both paper and computer readable billing formats available both to retailers and end users. There should be some data protocol standards to provide for the timely and efficient exchange of information among those with a need for the information (e.g. UDCs, retailers, end users).

Alternative 9.3.3.1 PRO:

1. Enables retailer flexibility while ensuring that customers have clear notice of who to call for help/information.

2. The competitive environment requires greater flexibility for UDCs.

3. Providing the option to receive UDC bills in either paper or electronic form will facilitate information exchange.

Alternative 9.3.3.1 CON:

1. Differing retailer bill formats may make comparisons by end users more difficult.

2. This alternative does not subject retailers to a regulatory framework similar to that imposed on UDCs requiring the UDCs to conduct their business in accordance with Commission-filed codes of conduct.

3. The electronic billing option should be provided if and when it is technically and economically feasible.

9.3.3.2 ALTERNATIVE: Partial Standardization of Billing Format Required

Billing should be standardized to the extent that it permits customers to better compare services. The Commission is currently considering adoption of a matrix of information by which customers compare billing and rate information. (Proposed Decision of ALJ Wong, R. 95-01-020.) Bills should be standardized so that they all provide certain basic information about rate, service and remedies. Each provider will have flexibility about how this information can be presented.

9.3.3.2 Alternative PRO:

1. Some standardization will facilitate the market development of products and services.

9.3.3.2 Alternative CON:

1. There is risk in delay of implementation while standards are developed.

9.3.4 Bill Enhancements

Bill enhancements refer to information conveyed on bills which is not directly needed by consumers to enable them to pay or validate the accuracy of their bill. Enhancements include information (text or graphics) about usage patterns, usage comparisons to similar customers, and effects of key drivers of use (e.g. weather or household characteristics) on usage patterns that make it easier for customers to understand bill impact consequences of their actions.

Utilities today use bill enhancements to varying degrees to convey information about current bill usage compared to past usage. However, no California utility has bill enhancements that compare a customer's energy consumption with that of similar customers. To do so would require additional investments and monthly expenses to capture and store customer descriptive information, perform analysis, and generate results reported on reformatted bills. The question has been raised as to whether the CPUC should require UDC and retailer bills to contain at least a minimum amount of bill enhancement information. The issue was raised at the end of the DAWG process with no time for discussion.

9.3.4.1 ALTERNATIVE: No Bill Enhancement Requirements should be Set

No statewide requirements for UDC or retailer bill information are necessary or appropriate.

Alternative 9.3.4.1 PRO:

1. In a competitive market, the CPUC should not dictate specific marketing practices, but rather leave them to retailers and UDCs to determine based on customers' wants and needs. If customers find bill enhancements of greater value than the cost to develop them, retailers and UDCs in a competitive market will naturally provide them.

2. If the Commission allows retailer access to personal-aggregate information to the same degree UDCs have access to it, there is no need to require improved bill enhancements. Either the market will naturally gravitate to the level of bill enhancements of value to customers, or, through Commission encouragement using PGC funding, retailers and UDCs will make changes to comply with yet to be determined bill enhancement public policy program design requirements.

3. There is no undue burden, cost or additional delay in implementation.

Alternative 9.3.4.1 CON:

1. Currently, all utilities include "self-comparison" bill enhancements on their bills, and do so because customers appear to appreciate the information.

2. Bill enhancements offer a relatively inexpensive means for furthering the CPUC's desire to educate consumers about energy use, which in turn helps customers make direct access and energy efficiency decisions.

3. Weather normalizing, energy consumption, and communicating usage relative to price signals are the most accurate and useful customer self-comparison information. Without this information, customers are limited in how far they can infer bill impacts associated with usage changes.

4. Comparing similar customers is useful to indicate how well a customer is managing its usage, and whether or not opportunity remains to manage usage even better.

5. Although the Commission could choose to require both retailers and UDCs to add more bill enhancements, encouraging them to do so through PGC funding availability may be as effective. PGC funding should only be made available in the initial stages to offset set-up and operating costs not recovered through direct customer reimbursements, and would be used only to transform bill enhancement to the more useful, expanded comparison information.

9.4 Customer Contact

There are a wide variety of circumstances that motivate consumers to call the utility in the present environment. Among these are: turn on/turn off, billing disputes, service interruptions, requests for service, notification of safety concerns, etc. Under the circumstances of the restructured industry, some of these calls would ideally to redirected by the customer to their provider of retail services.

9.4.1 Screening General Inquiries

it is unreasonable to expect that customers will be able to properly direct their inquiries to the proper entity without some training. It would be reasonable to request that retailers provide training and education to their customers about who to call for what purposes. It is unrealistic to expect consumers to adapt their instincts quickly, or to correctly anticipate who is responsible in all circumstances.

UDCs should retrain their customer contact personnel to screen inquiries and direct inquiries to the appropriate entity. Billing questions can be segregated from other inquiries, and since their is no emergency, a referral to another organizations billing representative is appropriate.

9.4.2 Billing Inquiries

The issue is under what circumstances, if any, do UDCs address end use customer billing inquiries relating to UDC or retailer services? Only one alternative was proposed.

9.4.1.1 ALTERNATIVE: UDCs Handle All Inquiries from Default Customers; Retailers Handle Inquiries about Their Services

UDCs will handle all billing inquiries of default customers. Retailers who bill end use customers for UDC services must answer bill inquiries about the services the retailer provides and may answer inquiries about UDC services. UDCs need not answer end user inquiries about retailer services.

Alternative 9.4.1.1 PRO:

1. Maximizes flexibility for retailers in determining the services they will provide and maximizes options for end users.

Alternative 9.4.1.1 CON:

1. There may be an increase in customer confusion.

2. Misdirected calls may be a problem. Retailers would need to reimburse UDC for incremental costs from misdirected retailer calls.

3. Retailers may not provide the same level of service as the UDC.

4. There is an increase in UDC expenses and effort. A UDC cost recovery mechanism would be needed for incremental expenses.

Chapter 10. Aggregation

Aggregation is a term with no standard definition. As used in the DAWG process, aggregation is a practice in which the loads of two or more customers are grouped together and matched with one or more generation facilities in direct access to generation services. In contrast to bilateral contracts, aggregation might be thought of as a multi-lateral arrangement. This chapter addresses how various options contribute to aggregation being achieved at low cost so as to be able to reach more customers, and the issues related to these aggregation options.

This chapter has four sections. Section 10.1 introduces the basic elements of an aggregation arrangement. Section 10.2 discusses issues associated with aggregation. Section 10.3 reviews the alternative aggregation models and their advantages and disadvantages. Section 10.4 reviews special rules for aggregation that go beyond the normal market rules discussed in Chapter 6.

10.1 Elements of Aggregation Arrangements

There are four basic elements to any aggregation arrangement, even though the consumer may not be fully aware of each of them. Each arrangement involves generation, ancillary services, interfaces with the UDC for distribution services, and some agreement (perhaps contractual) among the customer and providers of services.

10.1.1 Generation Services

Energy, which includes what was previously differentiated by regulation into"energy" and "capacity," is the essence of aggregation. This will include the aggregator procuring power from competitive spot, forward, and bilateral markets. Aggregators will be required to schedule and purchase power through a schedule coordinator who can interface directly with the ISO and the PX. The aggregator may be a schedule coordinator. The customer is unlikely to know of, or care about, the details of these arrangements.

10.1.2 Ancillary Services

The procurement of ancillary services by aggregators, through schedule coordinators, may be required. Ancillary services will include spinning reserve, non-spinning reserve, automatic generation control, voltage requirements, black-start capability, and option energy. Aggregators will, necessarily, also procure balancing services -- reconciling actual versus expected demands and loads -- from a scheduling coordinator. The scheduling coordinator will balance in real time with the ISO.

10.1.3 UDC Distribution Services

According to D.95-12-063, customers of aggregators will continue to be customers of the UDC, and will continue to make payments to the UDC under applicable tariffs for its services, for competitive transition charges, for public benefits surcharges, for low income surcharges, and any other CPUC authorized activities. Unlike the energy and ancillary services discussed above, some parties believe that the aggregator and the UDC will be performing similar, if not duplicative, services. These parties believe this concern can be resolved through distribution function unbundling. Examination of this issue has been undertaken by the Ratesetting Working Group. Irrespective of outcome of this issue, the aggregation arrangement must be made known to the UDC so that the UDC can make appropriate adjustments in its operations. At a minimum, the UDC needs to switch the customer to a tariff that recovers UDC costs in a manner authorized by the CPUC, which may be different than how such costs are recovered from those who remain energy service customers of the UDC.

10.1.4 Aggregation Agreement

An aggregation agreement between the customer and the aggregator specifies the scope, terms and conditions, and price for the generation services the customer acquires from the aggregator. It is likely to take some standardized form so as to reduce transactions costs on the part of both the consumer and the provider. It is likely to involve a few basic options, while customized details negotiated individually are more the province of a bilateral contract.

10.2 Issues Associated with Aggregation

There is a significant tension between desires to develop requirements for aggregation which reduce costs of services to customers, thus increasing the proportion of customers for which aggregation might provide net benefits, and desires to ensure that cost reductions to participants do not result in inappropriate cost shifting to non-participants. This section begins with a summary of the major differences among parties about aggregation, and then turns to a more specific discussion of: (1) distribution function unbundling, (2) mechanisms to reduce the cost of needed information, (3) cost shifting to non-participants, (4) the role of T/D interface node metering, and (5) the role of the UDC as a default aggregator.

10.2.1 Philosophical Disagreements About Aggregation

Since consumer buying power may not be evenly distributed across and within customer classes, there are concerns that customers will not have equal access to the competitive generation market. Developing aggregation arrangements and defining rules for these transactions appears to be very important in the new marketplace, because it is expected to be the vehicle through which most

customers can engage in direct access, and thereby exercise choice for generation service providers. There are two major philosophical perspectives about how to respond to this among which most DAWG participants were divided. These perspectives motivated disagreements about many specific topics.

a. *Facilitate Aggregation to Achieve Small Customer Benefits*. It follows from the consumer principles discussed in Chapter 2 that by reducing the transactions costs of participating in direct access, more customers will be able to participate in the market for generation services. Developing practices and rules that facilitate aggregation may be essential for most small consumers to achieve any benefits from generation sources cheaper than the PX.

b. *Ensure that Aggregation Customers Cover Costs and the Rules Are Fair*. If aggregation is pursued for its own sake, without such customers paying their fair share of costs, then those consumers remaining generation service customers of the utility distribution company (UDC) may be forced to cover any costs shifted from aggregation participants. This would be unfair. Aggregation should provide a tool to allow smaller customers to participate in direct access by reducing transactions costs through large numbers of customers making a "group buy" from a generator. Rather than creating market rules to ensure aggregation is successful, the rules should ensure that costs are allocated fairly, the market should be left to determine whether the degree of participation.

10.2.2 Unbundle UDC Functions to Reduce Duplicative Costs

There are several UDC distribution services which aggregators would like to have unbundled, so that payments to the UDC can be reduced to participating customers, and so that the customer can better accommodate the aggregator's corresponding costs. If the aggregator's customer service costs have to come out of the margin between the PX price and the aggregator's price for generation, then aggregators will be able to foresee net profits in a smaller number of cases, and fewer customers will be able to participate in aggregation.

Metering and communication systems, billing, and perhaps some customer service activities are those that have been identified in discussions to date. Metering services are expected to be differentiated in many ways, from the stock, vanilla service of basic interval metering to all manner of more sophisticated metering using two-way communications. Even existing time-of-use meters may be used to register the amount of daily peak, mid-peak, and off-peak power that is consumed. (See Chapter 8). During the transition and for default energy service the UDC may be required to provide metering, billing and their related services to aggregators. (See Chapter 9).

Some potential aggregators have asserted that margins on the commodity energy price between the PX and the price that aggregators expect to have to pay for generation will be small. Therefore aggregators wish to reduce any additional costs of participation in direct access and to avoid as much of existing UDC costs for aggregation customers as possible. These parties assert that natural gas core aggregation has not been as successful as it might because distribution

services were not unbundled and duplication between competitive supplier and LDC eliminated. These parties actively encourage a different path for electricity restructuring, so that services which are fully or partially duplicative are reduced or eliminated. While distribution function unbundling has been formally assigned to the Ratesetting Working Group, this subject's importance to potential aggregators and small customer representatives kept much discussion focused upon it.

The following perspectives have been voiced during DAWG discussions of these issues.

a. *Unbundle UDC Distribution Function to Avoid Costly Duplication*. Upon completion of a distribution unbundling function proceeding, as a result of which some service responsibilities are removed from the UDC and provided competitively, the aggregator would make its own arrangements for metering, data communications, billing, and perhaps consumption analyses, for each of its customers. If the customer's aggregator provides these services, then a corresponding UDC tariff excluding such costs would be used for such a direct access participant, thus reducing duplicative services and their costs. Some services might be contracted out, but since the bill is frequently viewed as an important opportunity for the marketer to provide a good impression on the customer, the aggregator might provide this service directly.

b. *Provide Flexibility to Aggregators*. Some parties have suggested a different form of unbundling in which aggregators or customers would have flexibility in selectively choosing unbundled UDC functions to provide for their metering, data communication, billing and customer service needs. They would like to select from options, such as: (1) the UDC unbundles its components, aggregators select some services to provide, aggregators bill the customer for all "utility" charges, the aggregator remits revenues for certain services to the UDC for those services provided by the UDC; (2) aggregators contract with the UDC to provide billing and customer service for them; and (3) various combinations depending upon the availability and cost of unbundled services. In this case, the UDC retains the capability to provide services, but the aggregator and the customer has the option to select the UDC as the provider.

c. *UDC Continues to Perform Distribution Functions*. Others note that UDCs still need energy consumption data, both for billing various aspects of UDC service as well as CTC, public benefits charge, and distribution system planning. If the aggregator wishes to meter and bill separately, then the aggregator could be permitted to do so. Duplication of activities is an overstatement, since what each provider needs and the timeframe it is needed in may not be the same. Further, the UDC only saves a portion of the allocated metering cost for each aggregation customer, since the costs of metering are a composite of investment recovery, fixed expenses to support a metering system, and variable costs of actually reading the meter.

This issue could not be resolved, since it involves CPUC policy as well as technical details. D.95-12-063 assigns certain responsibilities exclusively to UDCs. D.96-03-022 clearly begins a process of investigating distribution system unbundling, but makes no commitments to enact it or provide a schedule for this decision to be made. The Ratesetting Working Group filed a report on

August 26, 1996 that outlines several options for the CPUC to consider in resolving this ambiguity about the Commission's intent.

10.2.3 Reduction in Information Costs for Direct Access Participants

Many parties objected to the original concept that participants in direct access would all be required to have hourly interval meters and electronic communication systems capable of uploading usage data to the ISO on a daily basis for settlement of imbalances. The concern is about the cost of these metering and communication systems, particularly if direct access participants alone were required to have this equipment.

Two proposed solutions to this concern are: (1) to permit aggregators to use load profiles rather than to require hourly interval meters and electronic communication systems on aggregation participants, and (2) to require interval metering and communication systems for all customers, thus avoiding a cost differential specific to participation in direct access. Chapter 5, Section 5.1.4 provides an assessment of several alternatives concerning the issue of the need for hourly interval information to support ISO and PX activities. This section provides a brief summary.

a. *Properly Designed, Implemented, and Regulated Estimation*. It may be possible through load-profiling and allocation rules to allocate load imbalances across aggregators and UDC default customers in a manner which is acceptable and reduces potential cross-subsidies. Such market based solutions or CPUC administrative proceedings (if necessary) will undoubtedly be less expensive than deployment of expensive metering. Of course if the opportunity for direct access is to be widely extended to small customers in the initial years, then load profiling will be necessary since interval metering combined with electronic communication systems are unlikely to be broadly available. Both the English and Norwegian direct access implementation designs accept load profiling for customers below 100 kw of load.

b. *Universal Metering*. Some of the concerns arising from requiring expensive metering and communication systems just for direct access imbalance settlement can be resolved by universal deployment of hourly interval meters. This technology permits more precise cost allocation to individual customers, which for direct access customers would involve settlements on a periodic basis, and for UDC energy service customers would permit more precise allocation of PX costs. This technology provides the necessary data to make periodic settlements with the ISO/Schedule coordinator interface on any frequency desired. It also provides an improved basis for making load forecasts for direct access customers through their aggregator and scheduling coordinator to the ISO, and for UDC energy service customers to the PX. If hourly interval metering is universal, then its costs per customer may be substantially below that which might occur if deployment were piecemeal. (See Chapter 8, section 4 for estimates of cost by percentage penetration.)

The CPUC may wish to consider the following in making a decision on universal metering: (1) incremental costs of universal metering and data communication systems, (2) customer's

willingness to pay for the added costs (if any) relative to the benefits provided, (3) aggregator's willingness to serve small residential customers, especially under circumstances in which retail distribution services have not been unbundled, and (4) assessment of the role of accurate load forecasts in determining PX prices and ISO operations.

10.2.4 Cost Shifting to Non-Participants

While aggregators would like to reduce costs that their customers have to pay, to enable greater numbers of customers to participate in direct access, this may result in negative impacts on non-participants. Inappropriate cost shifting; mechanisms to reduce inappropriate cost shifting; legitimate, but undesirable rate increases for non-participants; and continuing difficulty with UDC obligation to serve/universal service have been discussed.

Cost shifting concerns have been identified for both distribution and energy services. Each will be discussed. Some cost shifting is inevitable by the functional unbundling and the segmented industry which D.95-12-063 directs. Some of the traditional instances in which revenues recovered exceeded costs cannot persist when customers have the opportunity to reduce or eliminate this situation by free exercise of choice. Their election to do so leaves net revenue losses that will have to be allocated in some manner. This section examines some instances where the cost shifting is inappropriate, not a broader set of instances in which it is merely unfortunate.

a. *Distribution Cost Shifting*. Cost shifting from direct access participants to non-participants will help facilitate direct access, but disadvantages non-participants, presumably because authorized revenues will continue to be recovered in UDC rates. For distribution costs this concern is accentuated if distribution functional unbundling is permitted, because aggregators will be more attracted to customers with low metering, data communication, and billing costs which will leave the remaining customers receiving both energy and distribution component services from the UDC with higher average costs. This situation is closely related to the geographic de-averaging concern expressed by many parties, but which has already been allowed by direct access.

b. *Protection from Inaccurate Load Forecasts*. One example is where customers cause loads to deviate from levels they are committed to pay for, making someone else pay for the load shift. In this example a customer using more onpeak energy than the load profile presumes would increase costs without contributing appropriate revenues. These additional costs come from more expensive PX purchases at peak load and settlement of the "out-of-balance" condition, because actual energy usage did not match scheduled usage. Customers who have hourly meters are held accountable for their load shape and settlements to resolve the out-of-balance condition. Thus, the problem of shifting costs will be driven largely by aggregated customers who do not have interval (hourly) meters. The UDC's customers who do not have interval meters may also contribute to this problem.

c. *Protection from Inappropriate PX Costs*. A potential concern is created when loads which are expensive to serve are provided by the PX while the direct access market serves inexpensive loads. An example is where a direct access customer buys its base-load power from a specific generator and takes its swing and peaking power from the PX. If the PX were to increasingly serve only swing loads its market clearing price (MCP) would continue to increase. Small and medium customers who do not have direct access options would be required to pay these higher prices. This problem will be exacerbated by the UDC's requirements to provide energy to all customers failing to exercise choice and to purchase all power for these customers from the PX, especially if proper hourly metering is not provided. UDC energy service customers would have a motivation to elect to use interval meters to "protect" themselves from cost-shifting, but might have neither the capital to afford the equipment nor the understanding to take this action.

10.2.5 Reconciling Customer Loads at T/D Interface Nodes

Parties submitting load bids to the PX or bilateral nominations to the ISO will use the transmission/distribution (T/D) interface node as a point of description. This permits the PX and/or ISO to know where the power to serve loads will be taken out of the system and where generation injections or transfers from other generator locations will be required. WEPEX has proposed to install a network of meters for purposes of monitoring the transmission system and its performance, but they appear to have determined that not all such nodes need to be metered to serve their purposes.

10.2.5.1 ALTERNATIVE: Install a Complete T/D Interface Metering System

Installation of a complete T/D interface metering system would be used to ensure that aggregators and UDCs serving customer loads would be able to have a firm point to reconcile estimates of loads being served. Installation and use of such a system would provide greater flexibility to energy providers for load metering systems at premises of final customers. The data collected by such meters would be used by the ISO to refine its allocation of imbalance costs, and would reduce the uncertainties of scheduling coordinators in assigning such imbalance costs to specific customers, especially when customers of aggregators or UDCs did not have interval meters.

Alternative 10.2.5.1 PRO:

1. Metering at the T/D interface is desirable to secure financial settlements for power flows and to provide a reference point for aggregation based on load profiles.

2. UDCs and private aggregators who use load profiling will need to reconcile the loads used by customers with the settlement of accounts for power with scheduling coordinators on some basis. As proposed by WEPEX to FERC (April 29, 1996 filing of the three IOUs), the scheduling coordinator settles with the ISO and PX on a daily basis. In order to achieve settlements for power at the T/D interface, interval meters which are revenue quality need to be installed.

3. This is necessary in order to define the costs for power, ancillary services, net losses, and congestion at the transmission/distribution interface. Settlements accounting can be improved by placing hourly (interval) meters at points on the distribution system upstream of customers. Without T/D metering and its use in settlements it is impossible to define the occurrence of major subsidy shifts that are inevitably caused by unmetered customer consumption. Resulting subsidies will be paid for in the increased average costs allocated to non-DA customers. Thus, interval metering at the T/D interface is essential.

Alternative 10.2.5.1 CON:

1. The cost of metering required for these additional T/D interface points and any incremental capacity required for the computer data processing systems which will handle the data generated is significant. The equipment for this level of metering is much more expensive per unit than the equipment discussed in Chapter 8 for individual customer premises.

2. Reductions in precision of aggregation customer load information by dropping interval metering should not be recouped by placing costs of T/D interface metering on the ISO for all customers to pay, even those who have interval meters and who are not in jeopardy of cost-shifting possibilities.

10.2.5.2 ALTERNATIVE: Allow the Market to Solve This Concern

The purpose for creating the scheduling coordinator was to shield the ISO from some of the complexity of settlement of imbalance costs. As long as the ISO can reasonably accurately allocate costs to scheduling coordinators, then the market can provide various mechanisms for allocating these costs to consumers. There may be diversity of methods in which to resolve these concerns. An obvious approach is for the customer to have an interval meter and communication system with daily data communications to the aggregator and scheduling coordinator, which will insulate the customer from any improper allocation. Of course the customer pays for this equipment and its use. Alternatively, the customer may have imprecise load data based on load profiles, and some estimation of his load and possibility of reconciliation of unknown loads may occur. This option may have lower direct costs, but result in higher "energy" expenditures. The customer can make these choices based on his preferences.

Alternative 10.2.5.2 PRO:

1. Consumer choice should be permitted to extend to the issue of precision of data required for participation in direct access.

2. Provided the allocation of imbalance costs are not biased, then relative accuracy of different approaches does not involve a public interest requiring imposition of general costs.

Alternative 10.2.5.2 CON:

1. Customers have no experience in markets where consumption is imprecise, and are unused to having to decide how much to pay for reduction of imprecision. This is a much more sophisticated issue than making a choice from among tangible products.

2. Even if total costs are not an issue, the CPUC has traditionally been very concerned with cost allocation among customer classes, believing that this was in the public interest.

10.2.6 Possible Distinctions Between UDCs and Aggregators

Some parties interpret the CPUC's December 1995 policy decision as suggesting that the UDC will act as the default aggregator. This is intended to provide for a means of "automatic aggregation" for consumers who choose not to choose. Different approaches to automatic UDC aggregation are now being discussed. This is essentially using the power exchange as the energy aggregator and the UDC as the billing agent, with the energy price averaged over some period, perhaps quarterly, perhaps more frequently.

Another view though, notes the clear distinctions between the UDC and an aggregator. Among these are: (1) the much wider range of services that the UDC provides; (2) the requirement that the UDC provide generation services to all requestors (essentially the guarantor of universal access); (3) the requirement that the UDC obtain all of its generation service from the PX; (4) specific requirements for the UDC to bid for power from the PX as opposed to negotiate for it, as can all other parties; and (5) UDC services regulated through tariffs rather than negotiated in a wide range of terms, styles, and approaches in a competitive marketplace. These differences require the UDC to behave in a different manner than a competitive aggregator, and make viewing the UDC as merely a super-aggregator difficult.

The distribution function unbundling investigation now underway in the Ratesetting Working Group may eventually lead to the Commission revising the responsibilities of the UDC as defined by D.95-12-063. Until that occurs, the UDC is not merely a super-aggregator.

10.3 Aggregation Models

A number of aggregation models have been discussed in the DAWG meetings, some which are alternatives to the UDC as default provider of power.

10.3.1 Competitive Providers

It is expected that the largest group of participants in the aggregation market will be private aggregators. Some of these entities are well known now. While the term "supply aggregators" has been used in this report, private aggregators are expected to provide a range of services from

simple power purchase and sale to complex offers of power and financial portfolios in combination with demand-side, metering, billing, and communications services. Among those that would qualify under FERC power marketer status, which currently number in the hundreds, might well provide private aggregation. Such aggregation would be purely voluntary.

10.3.1.1 ALTERNATIVE: Unconstrained Competitive Providers

Most DAWG participants understand aggregation to be a relatively traditional business arrangement, with widespread marketing to many consumers coupled with individual decisions of consumers to become customers of any particular provider. No constraints of geography, or affiliation, or membership in other organizations, in service relationships for other products would be required. This is the standard business pattern that everyone takes for granted.

Alternative 10.3.1.1 PRO:

1. This alternative is the natural expectation of most persons, and imposes the least constraints on the traditional customer/business relationship.

Alternative 10.3.1.1 CON:

1. Some consumers will not be pursued by aggregators, for various business reasons, reducing choice available to these consumers and creating a more inequitable industry than it is currently.

2. The absence of constraints may require various problems to be resolved in more costly ways than if these costs were able to be minimized by mandated restrictions on participation.

10.3.1.2 ALTERNATIVE: Geographically-Limited Providers

A geographically restricted aggregator might be required to confine its service to a specific region, a former utility service area, or a transmission/distribution system node. Such restrictions would be imposed because they solved some other data problem, not because they were related to issues of a competitive marketplace.

Alternative 10.3.1.2 PRO:

1. Geographic restrictions might make allocation of settlement costs from imbalances easier to resolve.

Alternative 10.3.1.2 CON:

1. These restrictions would be highly unnatural for most competitive businesses, and should not be imposed here.

2. Some potential aggregators simply could not operate the business plan that they have developed, because they anticipate marketing to their existing customers now being served in different markets that have nothing to do with energy. Such firms have developed business plans predicated upon joint billing of electricity and other products to reduce costs and enhance name recognition. Limiting aggregation to geographic areas would increase costs for these firms, if not forestall their plans.

10.3.1.3 ALTERNATIVE: Non-Public Affinity-Group Provider

Aggregation has sometimes been discussed in terms of affinity groups. Affinity groups are sets of end-users with pre-existing relationship which can be used by the energy marketer. Examples might include: associations of professionals, community organizations, churches, local chamber of commerce or business groups, etc. Such an affinity-based aggregation arrangement would not necessarily be open to energy users outside of the affinity group membership.

Alternative 10.3.1.3 PRO:

1. Marketers to affinity groups may be able to approach a ready-made set of potential customers with common interests apart from electricity consumption at relatively low cost.

2. Low cost mechanisms for aggregation (no interval metering, monthly settlement, limited opt-out) may rely on imprecise methods for allocating imbalance costs, affinity groups might be more receptive and comfortable with such a process than people or businesses with no prior relationships or pattern of trust.

Alternative 10.3.1.3 CON:

1. Limiting participation to strong affinity groups might be of concern from the perspective of non-discriminatory practices proscribed by the Consumer Principles in Chapter 2.

10.3.1.4 ALTERNATIVE: Utility Facilitates Aggregation

In this alternative, the UDC is given an incentive to promote the development of a competitive market for retail services, which may permit it to be removed from the "obligation to serve" requirement placed on it in D.95-12-063. The proposal has two parts, which can be viewed as

stages in market transformation: (1) initially the UDC acts as a market facilitator for other providers, and (2) eventually the UDC can act as a private aggregator.

In the first stage, the UDC would act as market facilitator and conduct competitive solicitations for default aggregation by other non-UDC providers. These competitive solicitations would allow many types of energy service companies to provide direct access and its related services to consumers. UDCs with unregulated energy service affiliates would be prohibited from providing energy services within their own franchise territories. This prohibition stems from a belief that unavoidable cross-subsidies and local market power problems would occur where a UDC interacts with an non-regulated affiliate. A UDC could, however, satisfy a prescribed set of conditions that would allow it to engage in competitive activities within its territory. There is no agreement about the nature of these conditions.

UDCs who met the established conditions would be able to transact as private aggregators in their own service territories and those of other UDCs. Presumably, if the UDC is no longer the default administrator of retail access and related services then, subject to demonstrating its lack of inordinate market power, it could provide competitive services. Thus, utilities could join the market with other private aggregators, to offer retail services through affiliates, subject to the above hurdles that establish the lack of retail market power.

The objective is to provide all consumers, including small and medium consumers with access to the benefits of choice in a competitive retail market. In this competitive market, consumers would be able to shop among competing retailers who seek to aggregate consumer loads, purchase power, and possibly provide special metering and enhanced services on a performance basis.

UDCs can be viable and effective agents to provide the market transformation from regulated bundled services to competitive unbundled services. Utility companies can exercise choice both by accelerating the market transformation thereby freeing their unregulated energy service affiliates to participate as private, competitive aggregators.

In sum, this alternative posits a shift in the role of the utility from a UDC with certain "obligation to serve" requirements to a facilitator of automatic aggregation through competitive providers and then to become one of many private aggregators in a highly competitive market.

<u>Alternative 10.3.1.4 PRO:</u>

1. Accelerate the development of a robust competitive energy services market and increases the presence of aggregators who will be available to serve all consumers, including small and medium-sized consumers.

2. Prevent the frustration of a competitive market by cross-subsidy and market power enjoyed by the investor-owned utilities.

3. Place the market-making responsibilities on a non-governmental entity with a vested interested in promoting competition.

4. Offer choice, rather than imposing obligation, upon the UDC.

5. Reduce the need for regulatory oversight and government-dictated market facilitation policy.

6. Alert regulators to inaccurate cost unbundling and inappropriate market rules for default aggregation.

Alternative 10.3.1.4 CON:

1. This alternative is predicated on the assumption that UDC's would be able to take advantage of cross-subsidies or market power to thwart competitive aggregators. Some believe that D.95-12-063 merely requires the UDC to flow power from the PX through to those customers wishing it, and that the UDC gains no financial advantage or returns from this choice.

2. Establishing conditions that would permit the UDC affiliate to operate in the UDC service territory would be difficult, and as a regulated decision subject to change.

3. This alternative presumes that non-utility aggregators will want to serve as default aggregators. Depending upon how costs are unbundled and market rules are set, competing default aggregators may not materialize. Tele-communication universal access provides some idea that the distribution monopoly need not be the default aggregator, but the extension to electricity is still unclear.

4. There may be some economies of scale or scope with providing universal access to electricity through the distribution monopoly. It is also feasible that any subsidies required to provide this service could come from sources other than regulated rates for energy consumers, thus allowing this function to be rate neutral.

5. Imposing a regulatory obligation on the UDC to act as a market facilitator creates the opportunity for regulators to micro-manage the market.

10.3.2 Local Government Providers

Cities and counties use electricity for municipal buildings, water and sewer utilities, traffic control signals, and street lighting. They take electric service under a variety of rate schedules: small and medium commercial, industrial, traffic control, and street lighting. Municipalities wish to have flexibility in their aggregation.

Some municipalities would want to aggregate all of their municipal electric loads. Other municipalities may want to diversify their aggregations. For example, a city with a water utility

could be interested in aggregating the water utility's electric requirements with independent water districts. Other municipalities would want to combine their entire municipal electric loads through a regional aggregation. They may want to use an existing or new joint powers authority to purchase electricity for specific uses, such as street lighting.

There are municipalities that are interested in aggregating not only their own municipal electric loads but also the electric requirements of consumers within their governmental boundaries. For example, a city might want the opportunity of aggregating all electric consumers within its city limits. This aggregation arrangement could be voluntary.

Most local governmental aggregation proposals attempt to reduce the cost of maintaining the franchise concept, through a municipal utility type entity or a local governmental entity that will only act as a purchaser or broker of wholesale power or other services for automatically aggregated customers. The new proposals seek to expand the options for the franchise concept, not to limit them. Thus, the proposals uniformly recognize the right of a municipality to create or continue a traditional municipal utility under existing statutes, or to pursue the "muni-lite" concept as part of the design of aggregation programs.

Three specific alternatives are presented: (1) local government as the default aggregator, (2) the muni-lite wholesaler, and (3) a joint powers agency serving municipal loads.

10.3.2.1 ALTERNATIVE: Local Government Default Aggregator

Formation of new entities authorized by new state legislation that designates local governmental units to automatically aggregate customers within their existing jurisdictions, but which may or may not exercise the same authority as traditional utilities and may own no distribution system or any substantial assets at all.

Alternative 10.3.2.1 PRO:

1. Reduced transaction costs to create a local government-based default aggregator compared to those to create a municipal utility and to acquire the existing distribution system.

2. Social welfare costs of universal access might be logically connected to government funding.

Alternative 10.3.2.1 CON:

1. Undertaking such a responsibility would probably require statutory changes, at least for some forms of local government, thus creating "overhead" to get such legislation passed.

2. Discussion of this concept in the CPUC restructuring process has centered on previous versions which were exclusive and mandatory, which seemed antithetical to consumer choice principles.

3. Additional "overhead" in the form of startup and marketing costs would have to be funded out of some revenue source, which might to difficult to accomplish in most local government situations given current budget and revenue realities.

4. Moving from a regulated IOU retailing function to a local government retailing function does little to enhance the goals of competitive marketplaces.

5. Enabling local governments to become default aggregators may raise concerns about hidden cross subsidies, either to/from electricity consumers.

10.3.2.2 ALTERNATIVE: Muni-lite Wholesaler/Retailer

Formation of a "municipal lite" utility that owns very little of the existing distribution system, but is eligible to pursue wholesale power purchases under the Federal Energy Regulatory Commission (FERC) open-access transmission rules and policies, perhaps combined with retail aggregation to its geographic sphere of influence.

Alternative 10.3.2.2 PRO:

1. Reduced transaction costs to create a "muni-lite" compared to those to create a municipal utility and to acquire the existing distribution system.

2. The direct use of open-access transmission powers and decisions of the FERN to gain access to the wholesale power market.

3. Transfer of cheap open-access wholesale power to retail customers through aggregation.

Alternative 10.3.2.2 CON:

1. The "muni lite" concept raises a threshold legal issue: how much equipment must an entity own to qualify as a municipal utility under existing statutory definitions to be able to operate under FERC open access rules? This legal issue is currently being raised before the FERC in a number of cases involving the efforts of various communities to gain access to the wholesale power market. These issues have been raised in other California community efforts. Culver City, the City of San Carlos, and more than a dozen cities in San Mateo County are actively pursuing the "muni lite" option. Similar efforts are underway or being seriously considered in various communities across the United States: Albuquerque and Las Cruces, New Mexico; Brook Park

and Toledo, Ohio; Broken Bow, Oklahoma; Bennington, Vermont; Westbrook and Jay, Maine; and Romeo, Michigan.

2. FERC has recently rejected an application by the City of Palm Springs to pursue a similar approach, on the grounds this is a "sham" transaction.

3. There are several other reasons to question whether pursuing the "muni lite" concept under existing statutes will be anymore effective than traditional municipalization efforts.

4. The cost and resources to establish the "muni lite" concept under existing statutes may be costly with no certainty of success in the long run.

5. A major issue with access to the wholesale power market is timing. Because of "surplus" capacity and the creation of a new or expanded power market, it is reasonable to believe that those who can get into the new market first will have the best opportunity to maximize benefits. Thus, even if the "muni lite" efforts are successful, the timing of that success in terms of ultimate benefits is likely to be very important. Other parties such as existing utilities, investor-owned or municipal, could be the prime beneficiaries of an extended conflict over the "muni lite" concept at the same time that the wholesale power market is being opened to increased competition.

10.3.2.3 ALTERNATIVE: Joint Powers Agency

Local government officials have discussed extension of the current joint powers agency (JPA) concept which could provide additional benefits to certain special sets of consumers. At least two such efforts are in process in California to provide reduced cost electricity purchase opportunities for the members of the JPA.

Alternative 10.3.2.3 PRO:

1. This approach is already possible for some limited sets of local government agencies, with no change in statutes required.

Alternative 10.3.2.3 CON:

1. Local government energy usage costs might be reduced, but this vehicle does not apply to the residents within the sphere of influence of the local government agency.

10.4 Special Rules for Aggregation

The specific rules that will govern aggregation services will depend on the nature of the aggregation program that is put into place. If, for example, customers are required to have hourly interval meters and the aggregation of such customers is left entirely to the competitive market, there are relatively few rules beyond those required of all direct access customers and competitive retailers. (See Chapter 6 for these market rules).

These generally applicable rules include the obligation of retailers to meet the certification standards described in Section 6.5, and the obligation of customers to sign a direct access service agreement with the UDC, as described in Section 5.3. All other service arrangements between retailers and their customers would presumably be the subject of private negotiations and would not be subject to regulatory oversight.

If an aggregation program is put into place that allows for the use of load profiles as a substitute for hourly interval meters, or allows for the "automatic" aggregation of such customers in geographically prescribed areas through legislative or regulatory mechanisms, a more expansive set of rules and protocols may be necessary.

There are three topics which are sufficiently linked to aggregation that special rules might be appropriate: (1) requirements for accurate load profiling, (2) cooperation between scheduling coordinators and UDCs in allocating imbalance costs among unmetered customers, and (3) special provisions for joint aggregation of electricity and natural gas.

10.4.1 Accurate Load Profiling

Load profiles are an estimate of the hourly loads of a group of customers. These estimates can be highly accurate if they are based on statistical sampling of customers, actual interval metering of some representative portion of the members of the group, and updated frequently. They can be highly inaccurate if they are based on literature studies and not adjusted to reflect actual usage from any members of the group in question. Many parties agree that it is possible to use load profiles in lieu of interval meters if done properly. The costs of the setup and ongoing overhead costs to ensure that load profiles are accurate are unknown. However, it is reasonable to believe that appropriate sampling rates of customers and the overhead to conduct this work would be cheaper than the metering and communication systems costs for every customer. If load profiling were more expensive or even of comparable expense, it would not be an effective strategy.

There appear to be two alternative approaches for developing accurate load profiles. First, one which relies upon standard statistical techniques. Second, reliance upon statistical techniques augmented by the use of upstream metering. Each alternative will be discussed.

10.4.1.1 ALTERNATIVE: Broad Elements of Load Profiling Accuracy Requirements

Most DAWG participants support the general concept of accurate load profiles, which might involve achieving the following objectives:

(a) ensure that an aggregator's load reflects its customers' actual loads;
(b) provide for timely settlements;
(c) reduce cost shifting;
(d) make use of existing IOU data as a bridge strategy to new samples and data collections methods; and
(e) interface with standard data communication systems used for customers on interval metering tariffs.

With these objectives satisfied, then load profiling could enable competitive access to power without the immediate need to endorse a monolithic, single vendor, customer meter implementation strategy, nor the requirement to defer participation until meters and data communication systems are available to large numbers of customers.

The following basic elements would be part of proposed standards to ensure accuracy of load profiles:

a. a standard of variance should be established that dictates the number of customers and homogeneity among customers for a given group;
b. a provider's customers should be segmented into as many groups as are necessary to satisfy variance standards;
c. existing utility load research samples are a satisfactory source of individual customer data, but customer measurements must be reweighted to provide load profile estimates for each subgroup, and energy service provider data must be used to replace IOU load research sample data within one year;
d. metering and data communication equipment for samples should share as much in common with standard interval metering and data communication systems as possible;
e. load profiles estimated from samples should be uploaded, processed and re-estimated on a daily basis;
f. sampling rates, sample selection, and estimation software should be audited by a scheduling coordinator at the energy service provider's expense to ensure accuracy in use of data and computation of estimates; and
g. disputes about accuracy of load profiles will be adjudicated by the CPUC.

<u>Alternative 10.4.1.1 PRO:</u>

1. With this approach, aggregators and customers can obtain essential market and power delivery information at lower costs than the case of customer-specific interval metering.

2. Aggregate load profile data can be examined without privacy or confidentiality restrictions, thus reducing some of the concerns about detailed customer information in the hands of private companies that cannot be regulated as closely as utilities to ensure customer privacy.

3. The costs of power delivered to specific parts of the distribution system can be known with more certainty than in the case of unregulated load profiling.

4. Customers can examine each of their competitive options, including the benefits of customer specific interval metering, and make a choice whether to accept a load profiling or interval meter measurement option.

Alternative 10.4.1.1 CON:

1. To ensure accuracy standards are achieved, some auditing function must exist, and the auditing entity will require disclosure of customer-specific load shapes in a usable form to infer average uses close enough to actual that a desired level of accuracy is reached. Thus another party has to has at least some access to customer information, and this creates even more concerns about privacy safeguards.

2. Some expect that the UDC may have a significant role in providing and processing this information so that customer groups can be targeted. To assist in the market transformation, the UDCs may seek to fulfill this role. If this function is unbundling, it can be expected that the UDC would be compensated for the development, provision, and processing of such data. This has been discussed in DAWG meetings. Some have argued that utilities should not be allowed to charge any higher price than incremental cost. Others have argued that without an incentive there will be no reason for the utility to make an effort to develop useful information.

10.4.1.2 ALTERNATIVE: Additional Requirements to Use Upstream, T/D Interface Metering

Some parties believe that a program of responsible load profiling would use upstream interval metering, at least at the T/D interface, in addition to the basic accuracy provisions described above in 10.4.1.1 They believe that upstream, hourly distribution system metering is still needed, even if hourly customer meters are installed, to ensure accurate measurement of loads at the T/D interface and proper settlements for losses (the difference between power generated and injected into a transmission node and power consumed by customers). As yet the WEPEX group has no plan to accomplish this metering.

Upstream or T/D metering would provide additional known control totals that would be used in conjunction with estimated load profiles to determine customer loads served by various suppliers. For example, if three aggregators, one UDC, and 15 bilateral contract suppliers

provided power to customers at a given T/D interface node, then the following steps might be used to allocate known load among estimates for each hour within a given settlement period:

a. subtract interval metered load of each of the 15 bilateral contracts from the T/D control total;
b. prepare estimates of total customer loads for each of the three aggregator and the UDC using standard load profiling techniques;
c. subtract interval metered loads of all customers of each aggregator with such meters and/or the UDC from the T/D control total, and similarly from the total load estimate for each provider;
d. develop the ratio of adjusted T/D control total to the sum of the adjusted estimates for each provider (the three aggregators and the UDC) with estimated loads; and
e. modify each original estimated load by the reconciliation ratio (the result of step (d)).

These steps show the benefit of having a known control total that can be used to reconcile estimates to ensure that all parties with estimates fairly accept costs. Each point where an upstream meter exists can have a similar computational process.

Alternative 10.4.1.2 PRO:

1. Upstream hourly metering is necessary to measure the total consumption of each aggregated set of customers. That is, the aggregated set of customers below the upstream metering point must show that they are paying for the load shape they cause to incur.

2. Added benefits to upstream metering are the features of voluntary participation by customers and the lowering of information barriers for aggregators. The customer has maximum control over market options and meter selection.

3. Absent a firm metering control total, there will be no end to the conflicts and regulatory tangles surrounding technical studies to determine billing responsibility and to justify profile analysis. Litigious conflicts over aggregation and load profiling will require regulatory oversight, defeating one of goals of reliance on competitive markets.

Alternative 10.4.1.2 CON:

1. This approach as too costly and unnecessary to obtain accurate load information.

2. Requiring upstream metering may limit customer choice to those downstream of such a meter.

3. Upstream metering *reduces* but does not *eliminate* possible misallocation of imbalance costs because a customer does not have an interval meter.

10.4.2 Cooperation with UDC and Scheduling Coordinators

In addition to the market rules required of any competitive generation services provider, an aggregator is likely to have to follow special rules because of the nature of its activities and their interface with a regulated monopoly -- the UDC.

10.4.2.1 Data Development to Understand T/D Interface Loads

With the formation of the ISO and PX, a greater understanding of T/D interface loads is needed, irrespective of the issues of aggregation. The loads at such nodes will be a composite of those being served under bilateral contract direct access, aggregation direct access, and UDC generation service. If load profiling is permitted by the CPUC, then primarily bilateral contract loads are likely to be traceable directly to customers. Thus both aggregators and the UDC have interest in understanding how their customer's loads link to this point in the system. Scheduling coordinators also have an interest since they are playing a role in transferring ISO costs for a certain portion of system imbalances along to the UDC and any aggregators sharing a T/D interface point.

Since the UDC and aggregators share loads on a common distribution system maintained by the UDC, these entities should cooperate to understand the estimated load pattern and the basis for that load pattern at various points on the distribution system. The UDC as aggregator can benefit from specific compilation of data to better understand how it can forecast specific customer loads. The use of upstream meters to verify and calibrate customer load forecasts is expected to provide benefits to both UDC and aggregator customers. Without specific upstream metering, the accountability for accurate forecasts and settlements would be significantly reduced.

The UDC, being the owner of the distribution assets, is in the best position to assist in the placement of such T/D interface node meters. It has the critical information necessary and has a direct interest in preventing misallocation of imbalance costs that would have to be recovered by UDC customers. Despite extensive discussion of upstream metering in DAWG meetings, the exact role of the UDC in facilitating T/D interface node meter placement remains unresolved. In order for any aggregator to use the data from such meters, the UDC will need to facilitate access to regional load data and to potential sites for meter placement. It is unclear how costs of T/D meters will be recouped in UDC customer rates, and whether there is an appropriate role for aggregation energy customers to pay a portion of these costs.

10.4.2.2 Aggregator and UDC Might Share Upstream Meter Information

The UDC and other aggregators can benefit from the use of upstream meters which provide a control total against which estimated loads can be reconciled. These upstream meters can be at the T/D interface nodes discussed previously, or can be downstream closer to customers on primary and secondary circuits. Since these upstream meters are not measuring individual

customer loads, rather groups of loads on the UDC's distribution system, it seems clear that the UDC must control meter placement and probably owns the data collected.

In light of the physical and ownership circumstances, how could upstream meter information be shared and used? There are at least two views that have not been fully explored with "pros and cons."

a. *UDC Controls Use of the Data*. This alternative suggests that as the owner, the UDC controls use of the data. Some question whether the UDC should be required to cooperate, unless it receives compensation in some manner. These parties believe UDCs should enabled to place such meters and sell the information derived from them to aggregators who require it.

b. *Aggregators Have Rights to the Data.* This alternative asserts that aggregators have full rights to upstream meter information, subject to an agreed-upon approach to share the information with the UDC. In light of the UDC's ownership of the data, the UDC should receive a reasonable cost for access to this data. It is critical that the UDCs cooperate in sharing information and facilitate upstream metering. The meter owner could offer services of data gathering and sharing, enabling aggregators to focus their resources on marketing and customer service. The metering company could offer its services to multiple aggregators in the same area, thus facilitating settlements among aggregators.

10.4.3 Joint Provision of Electricity and Natural Gas

The issues of aggregation of both electricity and natural gas has been broached in DAWG meetings,and while it has not been pursued, it has been identified as a topic justifying more effort. Since core aggregation is already permitted in natural gas industry, such aggregators may be examining how to extend their marketing efforts to electricity. It would be a sound business practice to attempt to sell both electricity and natural gas to the same customer, thus reducing overhead costs of reaching an agreement, and perhaps some physical costs for metering, billing, and customer service. To some parties, the discussion of duplicative costs for metering and billing apply equally to natural gas as they do to electricity, and most customers in California use both electricity and natural gas for some portion of their energy services. Therefore, the discussions about avoiding duplicate costs as a key factor influencing the success of aggregation are more complex than just for electricity alone.

It is possible that special rules or considerations will need to be taken for the situation in which an aggregator provides or proposes to provide both electricity and natural gas to a single customer. These include:

a. access to both electricity and natural gas customer usage data through a single release form;
b. computing what common costs are avoided and how this might be different that avoided incremental costs singly for the two fuels;

c. UDC/LDC treatment of revenues that an ESP collects from a customer that might be remitted to the electric UDC or the natural gas LDC, especially when these are separate legal entities.

Chapter 11. Consumer Education

This chapter addresses only a portion of the consumer education issues that DAWG has discussed. Since this aspect of DAWG's efforts is not scheduled to be filed with the Commission until October 30, 1996, the ideas presented here are preliminary. A much wider range of views has been encountered in DAWG meetings than is reflected in these limited proposals.

The following items are discussed in this chapter: (1) the scope and extent of education programs and materials, (2) responsibilities of the CPUC and role of various market participants for consumer education, (3) the role of community-based education programs, and (4) the electric education trust.

11.1 Educational Objectives and Programs

Most parties agree that consumer education is a key factor in achieving meaningful consumer choice. As discussed in Chapter 2 of this report, meaningful choice is the potential to achieve significant improvements in value received from expenditures made, by permitting individual consumers to select from market options with quantity or quality differences. Without the consumer empowerment the CPUC risks customer confusion, poor market information, disparate choice, disproportionate market power, and political backlash resulting from an undeveloped and poorly performing competitive market. As explained in Chapter 2, customers have the right to know, which is generally agreed to mean that customers should both have information available and have the means to understand how to use it to make intelligent choices.

This section reviews a partial list of educational objectives and program concepts that have been advanced by participants.

11.1.1 Emphasis of Educational Efforts

Participants appear to agree that there are appropriate roles for virtually all of the market participants and regulatory agencies. Unfortunately, there is major disagreement among participants about the relative emphasis to be placed on any of them. This leads to considerable disagreement about the specific objectives for various educational efforts. Some support educational programs designed to target specific customer segments with specific messages. Others hope to rely upon natural information exchanges as part of business transactions.

At the risk of polarizing debate with the extreme views, the following alternatives may help provide a sense of the different perspectives under discussion.

a. *Strong Equity-Based Education Programs*. An equity-based program approach presumes that consumers will require educational programs and materials that will permit comparison shopping for price, quality of service, provider track record, understanding of choices, quantification of risk and redress opportunities. Customers need to be educated against typical market abuses which they might encounter. A focus upon chronically underserved communities is necessary to achieve the overall goal. Community-based organizations are the best means of providing service to these underserved communities. The messages of these programs must be controlled to ensure that they are free from bias. Particularity for these communities, educational materials must be developed to serve people in languages of their communities. The CPUC must assume ultimate responsibility that adequate market information is made available to diverse segments of consumers.

This view suggests that it is important that for the initial transition years that this information dissemination and education activity not be needs-based or subject to a cost-effectiveness test. Educating small customers about their options will have to be deemed a competitive transition cost similar to treatment of stranded costs and ISO/PX infrastructure. It is an essential cost necessary to create a competitive marketplace. In later years, the publicly-funded education efforts may be less necessary and cost-effectiveness standards would then be applied.

b. *Reliance Upon Market-Based Efforts*. Relying upon market participants to convey much of the detail of product offerings and to raise consumer awareness will be more effective than any equity-based programs. The CPUC should work to reduce transaction costs associated with aggregation so that greater numbers of customers can actually be reached by market participants, rather than forestalled by excessive restrictions. CPUC mandated educational programs should be designed to teach how to make choices, how to use market information, and should be transitory, not permanent. Education expenditures should be needs-based and processes should be subject to continuing reviews of their cost effectiveness at delivering the "message" to the consumer. Public policy should be founded on societally cost-effective actions to avoid squandering scarce funds and resources. To ignore the long term cost-effectiveness of educational activities in deciding when and where to take action inappropriately funds low social value programs at the expense of those with greater social value.

11.1.2 Price and Quality Comparisons

If a consumer is unable to comparison shop for electricity services, then the market will fail. In order to shop, a customer must be able to determine value. In order to establish value, the consumer must be able to compare price and quality of competing services. Some believe that "competitive" markets don't always succeed in providing such information and that the long-distance, local-long distance telephone services, and the auto insurance industry are examples where industry has failed to properly apprise customers of essential information. (In response, the state's Department of Insurance has a program to assess and publicize comparative rates or customer service records for auto insurers. It is also statutorily charged with creating a "hotline" service for price comparisons to customers.)

Some believe that explicit education programs must be developed that would supplement the information provided by the private market. These efforts could include:

a. Monthly listing of licensed energy providers;
b. Bi-annual listing of price comparisons among energy providers;
c. Bi-annual listing of consumer complaint information;
d. Annually-revised glossary of energy service terms and description of services;
e. Telephonically-accessed listing of service providers whose license has been revoked, suspended or limited and an alert about unlicensed providers; and
f. Creation of representative service benchmarks for different types of customers upon which comparisons of service can be readily made.

Some believe this information should be made available to customers at no cost. It can be distributed though CPUC offices, community-based organizations, other state agencies and by all licensed energy providers. Others emphasize the need for this information to be available to English and non-English speaking customers.

Reflecting the above description of a more market-oriented approach, some believe that the need for this information should not be provided by extra-market means, or at least not beyond a transition period. UDCs or ESPs might also be used to provide this information, rather than by new organizations that must be created, staffed, and gotten up to speed in a short period of time.

11.1.3 Monitoring Customer Education by Private and Non-Profits

Some believe that the CPUC should go beyond ensuring that price comparison information and evaluative services are provided, and that the CPUC will be obligated to monitor private consumer education by market competitors and non-profits to ensure accuracy of the information.
There are four concrete steps that can be taken by the CPUC to improve the quality of consumer information in the market. These steps could include:

a. *Provide Materials.* The Commission should provide copies of its education materials to CBOs and other state agencies for distribution to clients.

b. *Provide Training*. As part of its public outreach and dispute resolution functions, the Commission should train individuals in CBOs and assorted social service agencies to handle electric service complaints. These designated individuals will then be familiar with the kinds of complaints and available remedies to customers who have problems with their newly competitive services. The individual could advise the consumer, help mediate a resolution or refer the customer to the CPUC and/or other appropriate entities for resolution of the complaint. This training effort could substantially increase the likelihood that consumers will get assistance. It

will also serve as an early warning system for potential systemic problems in the market and it potentially reduces the workload on the Commission's Consumer Services Division.

c. *Review Draft Materials*. The CPUC can also serve an advisory function for market participants. During the transition period, the CPUC should provide a service whereby it will review marketing materials voluntarily submitted by service providers to the CPUC. By undergoing an accuracy review by the CPUC, the market providers may be protected against possible private action for misleading or false advertising. And the CPUC is able to proactively prevent potential customer confusion.

d. *Hold Providers Accountable*. The CPUC must inform providers that they will be held responsible (to the extent consistent with law) for any fraudulent, deceptive or other unlawful marketing or billing acts performed by their agents and representatives, whether or not they attempt to insulate themselves by classifying such persons as independent agents.

11.1.4 Fostering Aggregation of Small Customers

Small customers may need to rely upon service by aggregators in order to participate in direct access to competitive generation services. Absent aggregation, these customers' costs will be linked directly to the performance of the Power Exchange. As demonstrated in insurance, banking and other complex services, aggregation of small customers can reduce transaction costs and increases market leverage. In newly established markets like electric and telecommunication services, it may be important that such aggregation occur, so as to give small consumers some opportunity to secure improved service and lower costs.

The CPUC is acutely aware of the problems faced by traditionally underserved communities. It has studied and is aware of low-income, senior, rural, ethnic minority, inner-city and other readily identifiable subgroups that have been disserved in telecommunications reforms. It is uniquely qualified to help identify to aggregators these communities by improving information and communication among potential customers. Some believe this task can not be left, exclusively, to the private market because they assess other market results as inadequate. There are at least two alternative views about how far fostering aggregation should go.

a. *Educate Consumers.* During the five to ten year transition period, the CPUC should be active in helping promote aggregation by properly educating customers. While the Commission should not directly assist energy providers, it can serve as a coordinator for private companies to find customers. For example, it can direct the distribution of information to the state's customers about available aggregators in rural, inner city and other underserved communities. It can establish a hotline where interested consumers can learn of the potential aggregators.

b. *Actively Facilitate Aggregation.* Some parties believe that the CPUC can be even more active and work with the private market to aggressively promote customer aggregation. It can assist municipalities and other public agencies who seek to create legal aggregators of electric or

phone services. It can list the aggregators' names and product information on the CPUC Web Site and make the information available at CPUC offices.

Chapter 10 of this report provides additional assessment of aggregation issues.

11.1.5 Direct IOU's to Provide Personalized Energy Usage Profiles to Its Customers

In order to effectively comparison shop, customers will need to be educated about their own energy consumption patterns and history of usage. It is unreasonable to expect that customers have saved their bills over the previous three years in order to secure this information. However, IOUs have collected a certain amount of historical data about its customers that can be used. There are various ways that the IOU can facilitate customer education about their own energy usage history, and its importance to their opportunities.

a. *IOUs Provide Customized Usage Profiles*. In order to facilitate customer evaluation of options, the IOUs could be directed to provide, upon request, an energy usage profile for an individual customer. Costs to provide this information should either be reimbursed by the customers or through cost recovery mechanisms that encourage IOUs to perform this function proactively. Profiles could include a chart and breakdown of monthly data for energy consumption and price paid for energy over the previous 12-24 months. In order to participate in a meaningful way in consumer choice opportunities, the electric customer needs energy usage history, data from comparable periods of the current and at least one previous year, adjustment for weather fluctuations, adjustment for price changes, comparison to other customers' energy usage and breakdown of expenses for major appliances. (See: W. Kempton, Improving Residential Customer Service Through Better Utility Bills, ESource SM-95-1, August 1995). The first energy profile should be offered at no cost to customers. Modest charges may be applied to subsequent profile requests. This profile will be the basis upon which customers can gauge their historical energy consumption patterns, better assess their energy needs and gain a sense of the cost of that electricity.

b. *IOUs Provide Raw Data*. IOUs could be directed to provide raw energy consumption and bill data for each billing interval in their active computer databases for a processing fee. Searching back into archived records would be an added cost activity. analysis to adjust raw data for price changes, weather, or other anomalies would be some the customer did, or an potential energy service provider, or a third party firm providing an analytic service.

11.1.6 UDC Bills to Promote Customer Education and Aggregation

The UDC will continue to be sending monthly bills to most small customers for distribution service costs. This bill packet has "unused space," owned by the utilities, that could be used to provide information. Because of the legal issues surrounding the utilities' bill envelopes, the IOU's consent may be required to include such inserts.

Other state mailers, such as DMV and tax-related mailers could also be used if state policy directed such inter-agency cooperation.

The UDC may provide a unique opportunity to assist with the low-cost distribution of important information to consumers through the use of the UDC's bills. These bills, paid for by all ratepayers but legally owned by the utilities, have additional room into which lists of qualified, certificated aggregators along with customer information about how to evaluate these services may be inserted. This vehicle helps reduce the significant transaction costs facing any service provider seeking to "crack" the mass market. Notably, this list can be distributed an information insert in a distribution companies billing packet, much like rate increase notices are currently distributed. The incremental costs of the insert could be defrayed by a contribution from those aggregators who are listed in the notice.

11.1.7 Special Assistance to Underserved Communities

Even under the traditional regulatory paradigm, certain residential customer groups have been underserved relative to other customers. In telecommunications, rural areas, low-income and minority groups, especially those with language-diversity, were not as well served as other customer groups. In a competitive markets, underserved communities will increase as private markets function to stratify social and economic classes. Residential consumers will be cherry picked because the underlying objective of the competitive market is to discriminate between those receiving cross-subsidies and those funding cross-subsidies. Unfortunately, the social objective of non-discriminatory electric services (c.f. Public Utilities Code 451, et. seq, 453 et. seq.) is undermined by this competitive reality.

Thus, it is incumbent upon the Commission to focus attention on potentially underserved communities, (e.g. rural areas, minority groups, seniors, renters, low-income, inner city and areas served by antiquated equipment). In a competitive electric market, market outcomes for some underserved communities may be determined by technological factors. For example, areas with distribution constraints or unusual climatic zones may prove unattractive to aggregators. The Commission will need to pay special attention to the intentional or inadvertent discrimination that is engendered by the competitive market. Chapter 2 outlined principles of universal access and non-discrimination which may need to be enforced, and both Chapters 10 and 12 addressed the issue of universal access from two different perspectives.

11.2 Responsibility for Customer Education Programs

The Commission must accept significant customer education responsibilities. Guided by the principles of Chapter 2 -- to make competition work, to make it work in accord with state policies to preserve equity principles, and to prevent abuse and foster competition in chronically

underserved communities -- regulators will need to ensure that consumers are provided the tools to participate in a competitive market.

With the new reliance upon the competitive market to provide basic electric and telephone services for small consumers, the CPUC's new challenges can be summarized as:

a. Promote a competitive marketplace with multiple buyers and sellers.
b. To arm all consumers with the information necessary to make informed choices through multilingual and varied media educational efforts, particularly targeted toward the most vulnerable.
c. Direct educational programs toward informing communities about potential abuses under deregulation, including how to safeguard themselves as consumers and what to do in case of fraudulent practices affecting them.

These three elements are essential components to a competitive market. This underlying premise compels the CPUC to take actions to adequately inform consumers of their choices of service and service providers. This mission can be accomplished with four strategies: (1) sponsor and disseminate price and quality comparisons of deregulated services; (2) monitor customer education conducted by private participants and administer an education trust funds for the electric industry; (3) work to help mitigate barriers to meaningful customer choice, especially in traditionally underserved communities; and (4) monitor customer complaints and alleged abuses by providers, both in terms of how well educational efforts are enabling customers to report problems and complaints as well as the level of potential fraud or abuse by new providers.

Section 1.4 introduced a general sequences of steps that must be carried out to ensure that direct access programs function properly, including customer education at several steps within the process. As outlined there, sometime during the summer of 1997, investor-owned utilities, the CPUC, a Consumer Education Trust, registered energy service providers, and others can anticipate beginning customer education programs as a start to the process of informing consumers of the general changes in how they will interact with UDCs and commercial businesses in the future. It is unclear which of these entities will carry the largest burdens, but the CPUC must be considered responsible to ensure that customers are educated. A major element of that education must include the opportunities to participate in direct access, which may include mass mailings, media messages, and various targeted literature intended to stimulate customers to respond to "open season" opportunities just a few months into the future.

Most agree that the CPUC must maintain an active role in a deregulated electric power industry similar to its role in telecommunications by providing a framework in which competitive players operate in a structured market; however, whether the CPUC itself should design and implement customer education campaigns can be questioned. The following four alternatives describe various options for focusing responsibility for education programs: (1) a direct implementation role for the CPUC, (2) reliance upon the IOU/UDC; (3) reliance upon the Education trust, and (4) reliance upon market participants. These are not mutually exclusive options.

11.2.1 ALTERNATIVE: Direct Education Role for the CPUC

This alternative places the CPUC itself into a direct consumer education role. Since a wide range of restructuring impacts are a direct result of CPUC decision-making, and since the IOU is being converted into a non-vertically integrated UDC, the role of the CPUC itself as an agent to educate consumers might be appropriate. CPUC Staff, CPUC-directed contractors, and other means would be used to deliver messages through various media to consumers.

Alternative 11.2.1 PRO:

1. reduction in the scope of the UDC, compared to CPUC D.95-12-063 and forthcoming retail unbundling decisions, accentuates the role of the CPUC as a consumer education/protection institution.

2. the CPUC would not have to rely upon market participants to provide an unbiased message to consumer.

Alternative 11.2.1 CON:

1. The CPUC has not played this role in the past.

2. The expenses of an extensive consumer education program, especially if electronic media are involved, could be quite large, thus increasing the necessity for CPUC staff and support funding.

3. As a government bureaucracy, the CPUC might have a more difficult time being responsive to customer concerns in a timely manner.

11.2.2 ALTERNATIVE: Reliance Upon the IOU/UDC

This alternative places principal responsibility for customer education upon IOU/UDCs. Since much of the elements of restructuring span beyond direct access, it is essential that the IOU/UDC play some role. The initial wave of consumer education will need to heavily involve utility resources and information delivery systems, perhaps with substantial CPUC oversight. The IOUs should be considered as an additional, if not an alternative, to an independent entity to impart to residential customers the information that they need to participate in a competitive marketplace.

Since IOU/UDCs are clearly under the direction of the CPUC, they can be used as the agent of the CPUC to disseminate a message to customers in ways that market participants could not be controlled. In addition, since it is becoming clear that UDCs will have little to lose or gain by "retaining" full service energy customers, they could be viewed as a more neutral party that

competitive energy service suppliers who will be expected to put a gloss on their materials to support their over marketing desires.

This alternative suggests that the CPUC could adopt a "template" for customers that wish to participate in direct access, spelling out precisely what customers needed to do in terms of metering, billing, nomination, and other technical requirements. A customer who provides evidence of satisfaction of these requirements would be considered eligible for participation, and if phasing is required, would be admitted into the selection process. The specific requirements of this "template" should be developed by IOUs, customers, and potential direct access providers, and approved by the CPUC before it is used.

Alternative 11.2.2 PRO:

1. The IOU is the only institution presently capable of mounting a major customer education campaign.

2. The IOU/UDC will have to be involved in fielding customer inquiries and complaints irrespective of policy decisions. Because IOU/UDCs have the customer service capabilities that exist now, and because they are the institution associated with customer inquiries and complaints, customers will call IOU/UDCs irrespective of what policy decision is made about educational programs.

3. IOU/UDCs have a longstanding relationship with various customers and local communities that would enable them to be effective in the short term.

4. The IOU/UDC can directly recover necessary expenses through rates, or as part of the "trust" arrangements now under consideration for ISO and PX development.

5. Ultimately, customers will hold the utilities at fault for upstream failures, so it is in utilities best interest to play a primary role in consumer education.

Alternative 11.2.2 CON:

1. Until retail distribution unbundling issues are resolved, ESPs may consider UDCs as rivals, and thus be unwilling to rely upon IOU/UDC programs to educate customers accurately.

2. Even if UDC responsibilities and financial incentives are adjusted to reduce or minimize reasons for UDCs to be biased, new generation service providers may view the UDC personnel as biased based on their former IOU responsibilities and practices.

3. IOU and UDC personnel have minimal experience in the fundamental consumer education processes that will be required.

11.2.3 ALTERNATIVE: Reliance On the Education Trust

This alternative provides principal responsibility for direct consumer education on the new education trust. This trust does not now exist. It was identified in D.95-12-063 as an entity to be assessed and implemented along the lines of some existing trusts under the supervision of the CPUC. The trust should be created immediately.

Alternative 11.2.3 PRO:

1. A trust would be independent of market forces and would be able to focus on consumer interests.

2. A trust would be able to operate uniformly on a "statewide" basis.

3. Trusts already exist in tele-communication areas.

Alternative 11.2.3 CON:

1. The trust does not now exist, and even if formed on the June 1997 date suggested in D.96-03-022, it would be difficult for such a new organization to be effectively delivering educational programs within a few months.

2. A trust provides independence, but this independence might lead to less effective expenditure of funds than direct CPUC activities.

3. A trust that is temporary would logically contract out much of its efforts, thus acting mainly as a conduit for funding; whereas if it were permanent it would create another bureaucracy.

11.2.4 ALTERNATIVE: Reliance Upon Market Participants

This alternative provides principal responsibility for consumer education about direct access on market participants, just like in other commercial businesses. Marketing campaigns can be messy and might be biased, but marketing expenditures are the principal source of information for consumers for the great majority of products bought and sold today. It is possible that fee-for-service or consumer interest groups might play a role in providing consumer education, eg. like Consumer's Reports does for household white goods, electronics, automobiles, and other products.

Alternative 11.2.4 PRO:

1. Market participants will provide the messages they believe are directly relevant to consumers selecting their product offerings.

2. Market participants need to develop effective message, and are far better at experimentation to find effective means of educating consumers than are IOU/UDCs or government agencies.

3. Taxpayers or ratepayers will not bear the costs, thus avoiding government decision-making rigidities or the complexities of regulated utility ratemaking.

Alternative 11.2.4 CON:

1. The information provided may be incomplete, biased, or even outright misleading.

2. Too much money may be spent as market participants attempt to acquire market share;

3. Market participants will likely stress the specific things important to consumers making a decision today, versus the longer run or bigger picture things that are important to other aspects of restructuring.

4. Some consumer confusion will arise from conflicting claims of various marketing campaigns.

11.3 Community-Based Education

The Commission has demonstrated the efficacy and effectiveness of community-based education in its implementation of a public education plan for CNEP (Caller Notification Education Plan). Recognizing that the introduction of CallerID would present new and important impacts upon telephone customers, the Commission required that Pacific Bell and other phone providers commence a "bottoms-up" education plan as a precondition for the commencement of CallerID service. Because Pacific Bell was determined to be the primary financial beneficiary once this service was offered by them to customers, the Commission required Pacific Bell to pay the full $32 million educational program cost for this product.

Although the purpose and need for education are very different between CallerID and electric industry restructuring, some parties believe that lessons learned from the Pacific Bell program may be useful when considering policies for electric industry restructuring. For example, the efficacy of that approach towards customer education is discussed in depth in "Evaluation of the October 11 Pacific Bell CNEP on CPN Delivery" by Professor Brenda Dervin of Ohio State University. That report, commissioned by the Commission's CACD and delivered on November 21, 1995, establishes a number of important principles for educating customers about changes in utility service.

Some of the features recommended by Professor Dervin and adopted by the Commission include:

a. *Independently Crafted Messages*. Professor Dervin stressed the need for involving community representatives in co-production of campaign messages. For CNEP, the

Commission approved the hiring of a nationally recognized media consultant to develop themes and mass advertising and sought the input of intervenors to refine the proposed themes.

b. *Use of Community Based Organizations (CBOs)*. The Professor emphasized the use of high involvement/high interaction outlets and recommended that at least 50% of the campaign need be implemented out in the communities. Recognizing the educational advantages offered by the state's existing network of non-profits, the CPUC required that these CBOs be hired to effect customer education.

c. *Early and Concerted Efforts*. A concerted education plan should commence six months prior to the beginning of the new regulatory scheme and be continued through the transition. The campaign must be iterative and sustained, according to Dervin. Accordingly, the CNEP began educating customers almost 6 months prior to the introduction of Caller ID service in California. The $32 million plan proved to be so successful that Pacific Bell could not accommodate the crush of customers seeking blocking protection and implementation was delayed until customer responses could be completed. The plan is to continue for one year after the introduction of the service.

Drawing upon these lessons from tele-communications, community-based programs should make the campaign relevant to customers. Electric restructuring is going to require a new awareness by customers of matters that had been heretofore largely handled by the monopoly utility. It will be essential that customers are educated, in simple terms, as to why they should care. The message must be interactive and accessible to all customer groups, including multi-lingual and multi-cultural communities. In addition, consumer education should be designed to prevent foreseeable abuses. Telecommunications deregulation foretells some of the marketing and other abuses that will come with electric deregulation in California.

Not only is it critical that consumer education begin well before-the-fact to inform customers that restructuring is going to happen and what it will mean to them, but they must also be educated to be informed about how to protect themselves from abuses by the unscrupulous. Language minorities, the poor, immigrants and limited English speaking will be most susceptible to targeting by potential fly-by-nights and quick buck artists abusing the Commission's certification and redress process. In all major slamming and marketing abuse cases prosecuted by the CPUC to date in telecommunications the unscrupulous practices have been focused primarily on limited English speaking and minority groups. Many of these victims have been charged rates two or three times higher than those of their previous carrier, as well as being billed for calls they never made. They must be educated both ahead of time and as restructuring progresses about how to evaluate and/or make informed choices among competing energy providers, what credit information may be sought, where to report suspected abuses, what to do if they are overbilled or slammed, where to go for redress, and what their rights are in terms of a provider of last resort. All information must be multilingual and culturally appropriate, and provision must be made for illiterate customers or those, such as the Hmong, without a written language. In evidence adduced recently before the Commission in the CTS slamming investigation (I.96-02-043), witnesses

testified that minority and limited-English speaking populations are targeted because of their propensity not to complain to authorities or not to know how to exercise their rights.

Five essential elements should be applied to the educational plans for electric restructuring, and should be linked to opportunities for direct access, since this is the first major choice that customers will be provided. This education effort should commence at least six months prior to January 1998 and may best be crafted by a qualified independent entity to impart to residential customers the following points:

a. Companies other than the local utility will be selling electricity.
b. Customers will have the right to choose these other services or stay with the local UDC.
c. In making that choice, the customer must understand prices, risks and personal usage patterns.
d. Utilities will provide customers with personalized energy usage profiles if they are reimbursed their cost to do so.
e. CPUC and/or others will provide customers with energy shopping information.

11.4. Restructured Electric Service Education Trust (RESET)

(This section is preliminary, to show some of the options under consideration by the Consumer Protection and Education Committee of the Direct Access Working Group. The final product on this subject will be included in the October 30 report, as scheduled by the Commission. However, the limited time available between now and January 1, 1998, dictates that efforts should begin immediately to clear the way for the creation and funding of the trust. If legislation is needed, the Commission should initiate the process now to achieve that end.)

The Commission has set the stage for development and implementation of an education trust as an important element to facilitate the success of its program to restructure the electric industry. Before developing a framework for a consumer education trust for electric service, let us look at two other trusts with educational aims, namely the Telecommunications Education Trust (T.E.T.) and the D.E.A.F. Trust. Some parties advocate a structure similar to the TET fund, with independent administration and allocation of funds to community organizations and others who are familiar with specific fraudulent activities in various communities, and who also have the confidence of the community.

Appendix J of this report provides an example charter for the Trust. It is not endorsed by DAWG. This charter takes the form of a legal document that embodies some of the approaches described in the remainder of this section of Chapter 11.

11.4.1 Telecommunications Education Trust

On December 22, 1987, the Commission issued D.87-12-067 which ordered Pacific Bell (Pacific) to create a trust fund called the Telecommunications Education Trust (T.E.T.). The T.E.T. was one of the programs the Commission ordered Pacific to establish to make restitution to ratepayers for abusive marketing tactics employed by the telephone company in selling certain telephone services. T.E.T. was established to further educational efforts and increase ratepayer understanding of the telecommunications system. Pacific's funding for T.E.T. was set by the Commission at $16.5M. The money was to be disbursed annually over a period of six years ($ 3M per year for five years; the remainder in the sixth year) to various community and consumer oriented groups and other organizations to implement certain outreach and educational projects. Trust funds were to be administered by a trustee (in this case, the trust department of a bank). A disbursements committee composed of DRA, Pacific, two consumer groups and the Public Advisor would meet annually to review applications for funds and decide which projects were to be funded.

11.4.2 The D.E.A.F. Trust

The second trust fund, the Deaf Equipment Acquisition Fund (D.E.A.F.) Trust existed in various forms since the early 1980s, when state legislation mandated a fund be established to provide special equipment and communication services to deaf, hearing impaired and disabled individuals. Funds were collected by placing a surcharge on intrastate telephone calls. In 1989, in response to complaints from various groups in the deaf and disabled communities, the Commission issued D.89-05-060 (May 30, 1989). This decision completely reorganized the administrative structure of the D.E.A.F. Trust.

Prior to this decision, under the jurisdiction of the Commission, Pacific administered the D.E.A.F. Trust and performed its day-to-day activities. The decision created one administrative committee and two subcommittees, and ordered the administrative committee to open and staff a D.E.A.F. Trust office to handle day-to-day operations. Each committee had representatives from the various constituent consumer groups, as well as personnel from the telephone utilities (including the communications services provider) and Commission staff. The 1996 Budget for the D.E.A.F. Trust was approximately $44M.

11.4.3 Comparison of T.E.T. and D.E.A.F. Trusts

The differences between the two trust funds are summarized below.

a. The T.E.T. was established to benefit all users of telecommunications services; the D.E.A.F. Trust was established to benefit only certain segments of the community.

b. The T.E.T. was funded as a result of a penalty levied on a utility by the Commission; the D.E.A.F. Trust was funded by a surcharge.

c. The T.E.T. was a temporary trust; the D.E.A.F. Trust is a Federally-mandated permanent fund.

d. The T.E.T. was established as a disbursement vehicle for restitution funds; the D.E.A.F. Trust is a subsidized activity from customers.

e. Each T.E.T. Committee member had one vote; on the D.E.A.F. Trust subcommittees, certain parties were standing members only and were not permitted to vote.

11.4.4 Restructured Electric Service Education Trust

The following three subsections provide an initial proposal for an educational trust. As noted previously, this is an initial proposal from a single party that will be reviewed in more depth as part of the continuing DAWG effort to review consumer education and protection issues. It is not necessarily constrained by current CPUC authority, since many changes in statute will be required to establish other facets of retail restructuring.

11.4.4.1 Scope

RESET is to be established to promote consumer education and understanding of forthcoming changes in the structure of the electric industry in California and to educate consumers about service options available to them in the newly competitive electric environment. Such efforts could include, but not be limited to: mass media programs, educational forums and community outreach efforts, paid for by giving trust funds to selected groups. Special efforts should be made to target certain groups such as the elderly, low income and non-English speaking communities. Experience in the restructuring of the telecommunications industry indicates these groups are targeted by unscrupulous companies and subjected to various forms of marketing abuse (i.e., "slamming" and "redlining").

Timing is a major issue, with respect to both funding and instructional efforts. Consumers must be educated BEFORE the market is declared competitive, as well as during the transition and afterward. In order that direct access can be implemented, a major responsibility of the education trust will be to ensure that customers are able to make informed choices in the market. For this to happen, massive and general education efforts must begin at least six months prior to implementation of direct access, i.e., NO LATER THAN JULY 1, 1997. Obviously, the trust must be established well ahead of that date. If legislation is required to create the trust, the Commission should make the appropriate overtures to the Legislature now to make it happen.

11.4.4.2 Funding

No detailed estimates have yet been made of the potential price tag that will be required to equipment consumers to participate in a restructured industry. The recent Caller Notification Education Program (CNEP) carried out by Pacific Bell to educate its customers about the new "Caller ID" service cost approximately $32 million. That program was limited in its content and was a one-time-only effort. The effort for electric restructuring will need to be more extensive, and last several years at least. Therefore, one might suspect that expenditures on the order of CNEP would be required each year. With these simple assumptions, if RESET were to operate for five years, it might expend about $160 million.

Funding should come from those companies who have a vested interest in doing business in California in the newly deregulated energy market. A budget for outreach and education could be agreed upon, and a fair and reasonable method of assessment of industry participants agreed to. In addition, an education fund of this nature could also be fed by fines or penalties levied by the Commission on service providers who violate the Commission's rules.

Long term funding mechanisms under consideration are as follows:

a. IOU funding, diverting funds already earmarked for DSM marketing and education, upon agreement by all parties impacted;
b. IOU funding, reimbursed in a manner to be yet to be determined;
c. Establishment of a surcharge, akin to the "CARE" surcharge or the Public Goods Charge (or included as a component of the PGC);
d. Fines and penalties levied on service providers; and
e. Private funding from advertisements included in educational materials.

Short term funding to establish the trust fund have not yet been seriously assessed by DAWG, but two alternative views are provided.

a. *Divert Authorized DSM Funds*. Consumers should not be required to pay for a program to educate them when the matter of whether or not the industry was to be restructured was beyond their control. At the outset, existing IOUs would be adequately reimbursed through regulatory mechanisms before being required to provide funding. A short-term funding mechanism might be to divert general rate case funding for DSM marketing/education programs to the trust. Such funding is already included in rates, so customers would pay, but they would not pay more. Whether this is permissible under CPUC ratemaking practices is unclear.

b. *Provide New Funding Recovered Through a Trust.* The assertion that consumers should not be required to pay for a program to educate them is simply a smoke-and-mirrors statement. If retailers pay for education, they will just pass the costs on to consumers. Once we recognize that consumers will eventually pay the bill, the question is how to recover the money in the most efficient and equitable means possible. Utilities should not be required to fund significant educational efforts without appropriate compensation. Perhaps this could simply be

another of the costs of a retail restructuring implementation trust that parallels that now being established for ISO/PX costs.

11.4.4.3 Administration

RESET should be administered by a committee modeled after the committee which administered T.E.T. Committee members should consist of DRA and other Commission staff (including the Public Advisor and outreach officers), industry participants, and various consumer groups. Committee members should be approved by the Commission and each member should have one vote. A trustee for the actual funds would need to be retained, as well as the services of an attorney. Fees for these services and committee operating expenditures should be approved by the Commission. (This includes expenses for consumer members, which should be subject to the same rules as those applicable to Commission staff.) The Committee should be responsible for reviewing various requests for proposals (RFPs) or grants submitted to it. An outside party (someone not on the committee) should be made available to assist parties with the writing of requests and grants. In other words, no group or individual should be automatically excluded from the process due to their inexperience in grant or request writing.

There are two disputed views about the criteria for membership on the administrative committee.

a. *Exclude Participants in CPUC Proceedings*. Criteria should be established for consumer members similar to the criteria established for consumers of the T.E.T. Disbursements Committee: (1) consumer members must have prior experience with mass consumer education programs; (2) consumer members must not have appeared before the Commission in formal proceedings, and (3) if consumer members are active in a consumer group, that group must be willing to forego competing for any monies the committee may grant or disburse.

b. *Select Capable Persons Irrespective of Their Other CPUC Activities*. Some parties disagree that appearances before the CPUC or involvement in CPUC proceedings should disqualify a person from serving on the administrative committee. This would exclude some of the most knowledgeable and capable organizations concerning impacts and implications of electricity restructuring from participation. These are also the same groups with the trust and confidence of minority organizations. There is precedent for parties to the proceedings which led to the TET fund to receive monies for community education purposes.

11.4.6 Monitoring and Evaluation of Trust Performance

RESET's administrative committee would be monitored by the CPUC and its performance evaluated on a routine basis. DAWG has not yet focused on these details, but periodic reporting and CPUC control over some RESET actions seem self evident.

11.4.6.1 Periodic Reporting

The Trust committee would periodically report to the CPUC on the following items:

a. Amounts of money disbursed.
b. Names/Identities of fund recipients.
c. Purpose of programs funded.
d. Summaries of educational efforts, including: (1) What was done?; (2) Who was the target group?; (3) What was the impact of the effort? (How many people contacted? What was the response, if appropriate?)
e. Account balances.

11.4.6.2 CPUC Control Over Certain Changes

A Commission resolution should be required for the trust committee to do the following:

a. Change the identity of the financial advisor or trustee.
b. Change either the committee structure or its membership.
c. Change the terms and conditions of the trust.
d. Obtain approval for an operating budget.

11.4.7 Concerns with a Trust Approach

Experience with other trust funds has shown that certain problems have arisen with the trust fund process. These problems are primarily in the area of definition of roles of the members and conflict of interest. Some parties believe that the RESET fund can be established in such a way as to avoid problem areas by implementing measures such as those listed below.

a. Voting Rights. Each member of the committee should have one vote. If a vote is tied, the Public Advisor should cast a tie-breaking vote.

b. Either experts should be hired to conduct a consumer outreach program, or the groups given funds should have extensive experience in this area.

c. Before any outreach education programs are conducted, ways of effectively monitoring efforts and measuring outreach results should be agreed upon by the committee.

d. The roles of committee members, the committee itself and the Commission should be distinctly defined.

e. Conflict of interest rules need to be explicitly defined and understood by everyone.

f. A "sunset" clause needs to be included in the terms and conditions of the trust.

Chapter 12. Consumer Protection

This chapter addresses specific activities explicitly designed for consumer protection. Several of the consumer principles described in Chapter 2 are applicable to consumer protection issues. Broadly, there are two categories of these activities: (1) design of the market rules to minimize conflict and potential for problems, and (2) mechanisms to resolve customer-specific disputes and redress for systematic problems encountered as markets operate.

This chapter provides an initial sketch of these issues, but further detailed proposals should be expected in the scheduled submission of DAWG's consumer protection report on October 30.

12.1 Design of Market Rules

Design of market rules should address consumer protection concerns from the outset. The expected magnitude of problems should be reduced if intentional efforts are made to resolve likely problems before they take place. These actions can aid both consumers and suppliers, and society in general, by making markets operate more efficiently.

Chapter 6 of this report discusses market rules for the various entities that will operate in the restructured industry. Several of the consumer principles have been addressed there. Chapter 7 addresses the issue of consumer privacy along with facilitating market efficiency in the context of access to customer information. The remainder of this section addresses two key consumer principles that are not addressed elsewhere in this report.

12.1.1 Universal Electric Service

While direct access will make the generation service and supply industry partially competitive and, therefore, an appropriate object for market-determined rates, electric service continues to be an essential service and "affected with a public interest." The CPUC policy decision to rely upon the Power Exchange spot market via the UDC as the source for generation services to end-use customers, and to deny proposed restrictions on return to UDC generation service, may place the UDC's customers in a difficult position. There are two separate, but related concerns. First, some customers may find electricity service more costly compared to their income and personal circumstances. Second, a UDC obligation to connect is different from a utility obligation to serve with designing universal access programs.

12.1.1.1 "Obligation to Connect" versus "Obligation to Serve"

The responsibilities placed on the UDC in D.95-12-063 have a dual nature. First, the UDC encompasses the distribution function and has an "obligation to connect" all customers to the

transmission grid, and hence to the competitive generation industry. Second, the UDC is obligated to provide power from the PX at the PX price with no markup to all customers who wish to retain UDC generation services. The sum of these two UDC responsibilities is neither the traditional utility obligation to serve, nor merely the provision of default aggregation services. When evaluating issues about affordability of electricity the specific responsibilities of the UDC and direction provided it by D.95-12-063 have to be taken into account.

12.1.1.2 Affordability of Electric Service

Affordability of electric service has been a state and national concern for many decades. The federal government ended up subsidizing rural electrification to bring the clear benefits of electricity to rural areas that were underserved by utilities. Some believe that California's affordability concerns have generally been an income issue rather than an access issue. The CPUC has traditionally required low income programs to ameliorate these difficulties, but the legislature has required a baseline rate design for the residential class, at least in part from concerns about affordability. The CPUC has sanctioned a Low Income Working Group which will provide a detailed report on these issues to the Commission.

Some believe that if low cost of service customers leave UDC generation service as a result of direct access providers marketing allures, then the average cost for the remaining UDC generation service customers will increase. As this situation progresses, the above average costs of UDC generation service customers may result in substantial cost differentials for UDC generation service. In effect, requiring the UDC to be the "default provider" isolates higher costs on those who fail to leave UDC generation service. For those who fail to leave because of inadequate education, information, or other factors not connected to higher costs of service, this is an unfair penalty.

Following this logic, this situation is exacerbated as aggregators more successfully serve broad numbers of residential and small commercial customers, and the more retail distribution function unbundling permits customers to avoid UDC service for components of service beyond generation. Customer service costs (now masked by the historic practice of geographic averaging) may be quite variable, and average costs of customer service could escalate substantially if UDC customers with low cost of service are attracted to aggregators, thus leaving high cost of service customers behind.

Two components of electricity costs should be examined separately.

a. *UDC Energy Prices.* There are a host of circumstances that may cause PX prices to be higher than what might be desirable or appropriate. To the extent these prices for generation lead to affordability problems for consumers, the solution lies outside of the UDC. The UDC acts a conduit for PX electricity, but whether and how well the PX accomplishes its role as a spot market for power is not something the UDC can control, nor has any financial interest in. There are obviously many ways to subsidize prices, but these would violate economic efficiency

principles. Alternatives which provide appropriate cost subsidies to specific customers based on their income and personal circumstances are more compatible with societal economic efficiency.

b. *UDC Distribution Costs*. Since the costs of the distribution system and the rate design to collect revenues required for it are the province of the UDC, and under the control of the CPUC, access and affordability of "obligation to connect" are more controllable. However, an affordability issue arises if various proposals for "two part" tariffs seeking to better match prices to fixed and variable costs are pursued. Such proposals have merit from an economic efficiency perspective, since as a general rule rates should reflect costs. However, it is possible that a two part tariff structure could lead to considerable fixed costs and relatively low variable costs, adversely impacting smaller, low usage consumers. Low income customer subsidies should then become focused not on reducing energy costs but on providing access to the distribution system. Two part tariffs are even more likely to be an issue with "geographic de-averaging" in which rural consumers might be asked to pay far higher fees to connect to the distribution system, which more closely match their cost of service. This change in broad geographic averages for pricing electricity access is analogous to that already accomplished for many water, sewage, and street services provided by local government.

In light of this, some believe that the CPUC's efforts to achieve universal service for tele-communications through a surcharge on all users (or from government sources), and thus making high cost of service customers potentially profitable for all suppliers, rather than requiring a single entity to be a "default provider," may be a idea deserving further investigation.

12.1.2 Transactions Costs

Reducing transactions costs is an important feature of aggregation, and Chapter 10 addressed the nature of aggregation as a means to reduce those aspects of transactions costs directly related to the overhead of supporting an energy service provider/customer relationship.

An important additional consideration for transactions cost minimization is inducements for trustworthy market information that customers use to identify, evaluate, and compare options. If customers find that market information is plentiful, understandable, and accurate then they will be more comfortable making choices in reliance upon it. If customers find that market information is not trustworthy, then they must search out their own information to understand choices, and the level of expected net benefits of action decreases, thus reducing the number of transactions and the effectiveness of the market.

The concept of meaningful consumer choice suggests that efforts to ensure that market information is trustworthy should be pursued. The market's information practices should not necessarily be left to themselves. Failure to detect and punish market suppliers who promote themselves with inaccurate claims and false comparisons to others poison the entire market, not just themselves. Consumer protection efforts should be designed in advance to discourage these practices, and to seek them out and correct them as markets operate.

Many believe that comparisons among long distance telephone providers are virtually impossible to find, and are concerned that there will be a comparable situation once aggregation and competitive supply of generation services through direct access becomes available to all customers. Suggestions of industry or CPUC efforts to collect and publish comparable information about prices for energy services have been made, but the details of how such efforts might be organized have not yet been pursued.

12.2 Mechanisms to Resolve Complaints as Markets Operate

Once markets begin to operate, there will be two problematic categories of activities. First, customer-specific complaints where services provided do not match the customer's understanding of what was offered. This requires some dispute resolution process. The principle of redress is applicable. Second, more systematic marketing abuses where whole classes of customers are either being excluded from the market, or where discriminatory practices are being applied. The principle of fair dealing applies here. Each of these will be briefly reviewed. Further effort should be expected as part of DAWG's report scheduled for October 30.

12.2.1 Right to Redress

The Commission has provided the means by which redress for disputes has been available to individual customers and to advocacy groups. As the industry is restructured, everything must change to some degree. As a tightly regulated industry gives way to an increasingly competitive one, there will probably be a greater level of consumer disgruntlement over transactions issues, as opposed to CPUC-regulated "price" issues. As a philosophical approach, consumers must be asked to act responsibly, and to "pay the price" for mistakes they make, and hope that these mistakes contribute to consumer education about this industry. It would be a mistake to design a redress process on the presumption that the consumer was right and the supplier was wrong. Consumer ignorance will surely lead to many consumer misjudgments, but these should be resolved through education rather than specific complaint resolution.

For those disputes where a legitimate complaint exists, a mechanism for redress may have the following broad features: (1) consumers should have no cost or low-cost access to redress, (2) dispute resolution forums must be neutral, (3) mediation should be encouraged, (4) penalties imposed upon providers should be used to solve industry problems, (5) complainants should be able to access CPUC-compiled market conduct data consistent with confidentiality requirements, and (6) the CPUC should be able to refer patterns of abuses to other authorities. Each of these items will be briefly explored.

12.2.1.1 Consumers Should Have Appropriate Access to Redress

Where complaints by consumers can not be readily resolved by a service provider, an individual consumer should be afforded access to regulatory redress. This is the status quo and it should be preserved during the transitional years, at the least. There are at least three versions of how such access might be provided.

a. *Prompt, No Cost, Effective Access*. Regulatory oversight must continue to ensure that there is prompt, no cost and effective forums for receiving customer complaints against electricity providers, resolving the complaint satisfactorily, and instituting investigations where warranted. This access must provide complaint resolution for limited and non-English speaking customers. Consumers should have the right to petition for enforcement actions. Pending resolution of any investigations against providers charged with defrauding large numbers of consumers, the provider should be ordered to post a bond sufficient to satisfy any likely judgement if the provider's place of incorporation is outside of California or where there is evidence of financial instability.

b. *Low Cost Access.* Access to low-cost regulatory relief means that the consumer should not be charged any filing fees to initiate the process and assessment of costs for pursuing regulatory relief should be reasonable. It does not mean that the time spent pursuing a case or travel and out-of-pocket costs will be necessarily recovered by the complainant regardless of the outcome. However, where an individual prevails in a regulatory complaint, the damages awarded should include reimbursement of costs incurred in pursuing an action in addition to restitution normally awarded by the CPUC. This low-cost redress is essential if the Commission is to encourage consumers to bring complaints to their attention. It is also necessary to level the playing field advantage enjoyed by better-resourced providers.

c. *Balanced Redress Mechanisms*. Consumer complaints should be screened to determine their merits. Consumer mis-information and confusion should not lead to excessive costs for providers. Dispute resolution mechanisms should focus redress on failure to deliver services, not consumer confusion about the service. Providers falsely accused should not have records complied that co-mingle dismissals of complaints with settlement of complaints.

12.2.1.2 The Forum Must Be Neutral

The forum in which complaints are resolved must be neutral. The arbitrators need not be administrative law judges, but they cannot be representatives of, or affiliated with, energy service providers. Ideally, the use of trained, but local arbitrators, to conduct formal hearings and render recommendations that would be reviewed by the decision authority. An evidentiary record should be kept, but it can be taped, rather than transcripted.

The Commission's current expedited complaint process is an adequate process by which formal complaints can be cost-effectively heard and decided.

12.2.1.3 Mediation Opportunities for Complaints

Mediation and other alternative dispute resolution tools should be encouraged. However, they can not be compulsory. Nor can a consumer be penalized for not submitting to mediation.

As a means of encouragement, local mediation should be made available to an individual complainant within two weeks of filing a complaint. If mediation is chosen by both parties, the individual consumer should have available the presence of a trained, knowledgeable advocate or a qualified intervenor advocacy group representative at the mediation to assist on behalf of that individual.

If the parties do not choose mediation, then the expedited complaint process should be made available to the complainant.

12.2.1.4 Disposition of Penalties Collected

Not all complaints will result in penalties imposed upon service providers. Most complaints will either result in restitution to the complainant or will be found to be warrantless. However, some believe that where a pattern of abuses is discovered and proved, the regulatory agency should be empowered to impose penalties upon a licensed service provider. This may require new statutory authority. Severe, systematic violations may result in license suspension or forfeiture of bonds. Where a financial penalty is assessed, the proceeds should be applied to promotion of consumer education, advocacy, and/or a damages pool which would be available to provide restitution for those who received judgements but were unable to collect from the provider.

12.2.1.5 Access to CPUC-Compiled Data

As part of its on-going market conduct oversight responsibilities and as part of its customer education duties (as discussed under Chapter 11. Consumer Education) the regulatory agency will be compiling data about the complaint records, financial viability, prices and service quality of any and all service providers licensed to do business in California. Much of this data may be made available to consumers who are shopping for energy services. However, some believe all of this data should be made available to complainants that have filed formal complaints to appropriate authorities about an energy provider(s). Others believe only relevant data should be made available subject to confidentiality restrictions.

Some believe that in assessing a complaint against an energy provider, the agencies must consider not only an individual isolated complaint, but also whether a pattern of inappropriate business practices is extant. Complainants must have access to such data and must be able to enter it into an administrative record in order for the data to be fairly adjudged by the Commission.

12.2.1.6 Resolution of Systematic Patterns of Abuse

Ongoing review of market conduct will lead to identification of patterns of abuse or misconduct by energy service providers. There are several alternative approaches to resolving systematic patterns of abuse. These have not been fully reviewed or assessed, and are presented to provide a sense of the range of options expressed by some within DAWG.

a. *Publicizing Market Abuses*. In order to make maximum use of limited staff resources, the regulatory agencies should share their market conduct findings with appropriate public and private bodies. One of the regulatory agency's roles could be to facilitate public prosecution of misleading information. For example, when companies engage in inappropriate marketing transactions, the state attorney general, local district attorneys and consumer class-action attorneys can utilize the state's Business & Professions Code to discourage such behaviors and gain remedies for victimized consumers. A regulatory agency could serve as a clearinghouse for complaints.

A regulatory agency's public intake functions are essential and low-cost means of identifying such abuses. The prosecutorial authorities can expeditiously act once a regulatory agency makes public the fact that complaints to the regulatory agency indicates a pattern of deceit. While the regulatory agency would not be acting as a referral panel, the disclosure of complaint information will enable interested private parties to pursue remedies independent of the agency. Such an approach is now operative at the CPUC. A regulatory agency's resources are best utilized as a collector and distributor of information first, and a prosecutor second. However, where no private attorneys are willing or able to pursue a case, the regulatory agency is obligated to self-initiate regulatory action or to instruct its staff to pursue civil or criminal remedies, where warranted.

b. *Regulatory Sanctions*. A regulatory sanction approach could be used when problems are isolated to specific firms or providers of services. As noted previously, the telephone "slamming" practices have been concentrated on particular language and cultural communities by a few operators. Such a problem is best resolved by regulatory agency investigation, prompt customer redress, and where warranted, by sanctions against such operators. For this to be workable, however, requires that the regulatory agency have remedies that are sufficiently strong to be effective deterrents. This might imply that all providers are certified to do business, or that bonds have to be posted for good performance relative to explicit codes of conduct, or both. Egregious practices might result in certificate revocation or forfeiture of the bond.

c. *Statutory Reforms of the Marketplace*. If widespread patterns of abuse are found across multiple providers of energy services, this may be evidence that the market rules themselves are too weak or are ineffective. Legislative remedies may be required in this instance. Since a greater portion of the electricity industry may be operating outside of the CPUC's traditional corrective authority, it is feasible that legislative remedies may have to be sponsored by the CPUC or other regulatory agencies supervising the industry.

12.2.2 Fair Dealing

The consumer principle of fair dealing addresses several practices that are known to be problems in other industries, which might also become problems in a more competitive electricity industry. Two specific concerns are: (1) discriminatory marketing practices, and (2) discriminatory credit and deposit rules.

12.2.2.1 Non-Discriminatory Marketing Practices

Generation service providers should not be permitted to engage in discriminatory marketing practices. In the past few years these practices have become widespread in the tele-communication industry and there is reason to believe that these practices might arise in a competitive generation services industry as well.

Of special concern are marketing efforts addressed to limited-English communities that require special materials to be understandable to residents. Cultural differences combined with language limitations make these communities subject to abusive marketing practices. The tele-communication practice of "slamming" is a possibility for generation services marketers.

Electric service, by any ESP, should be equally-available to all similarly-situated potential customers. The CPUC has an interest in controlling “cherry-picking” and preventing “redlining”. This would not prevent customers from bearing the appropriate costs of capacity expansion for relevant customer information activities.

An advantage of registration or certification of energy service providers is that evidence of abusive marketing practices could be grounds for decertification. The mere existence of such a penalty might minimize the extent of the problem, which would be a far better solution than hundreds or thousands of customer-specific dispute resolution efforts.

12.2.2.2 Non-Discriminatory Credit and Deposit Rules

Direct access and retail restructuring in general will create confusion about appropriate credit and deposit rules. The unusual feature of electric and natural gas service of appropriate payment for consumption being determined after the fact of consumption suggests, properly, that deposits have been a reasonable practice. This is likely to be the case in the restructured industry as well. Deposit practices should not, however, be a means of discriminating against communities. Personal credit histories may be a legitimate consideration, but cultural or language affiliation are not. Two alternative views of appropriate mechanisms to govern terms and conditions are shown below as illustrations of the disparity of views that have not yet been resolved.

a. *CPUC Supervision of ESP Offerings.* All ESPs should be required to offer publicly-supervised Terms and Conditions of service. For UDCs, subject to high standards already for regulated monopoly activities, such Terms and Conditions would be subject to significantly less regulation than regulated monopoly services since they are voluntary contractual agreements.

b. *Reliance on the Marketplace*. Except in the areas of public safety, terms and conditions of service between an ESP and customers need not, and for competitiveness reasons, should not be publicly-supervised. In an open market, there is no need to regulate what services are packaged with the electricity commodity sale, and the terms and conditions surrounding that sale. Regulation will only stifle the emergence of creative customer solutions and diminish the competitiveness of those with new ideas.

12.2.3 Alternative Agencies Responsible for Consumer Protection

At this stage of DAWG's investigation, there has been no systematic investigation of the alternative agencies that might be charged with supervising the restructured industry. It is possible that several agencies might split various responsibilities. The following brief discussion is intended to provide a sense of the alternatives that have been identified.

a. *Expanded Authority of the CPUC*. Clearly, the CPUC is a leading contender for expanded authority to regulate new entities within the industry. The CPUC has traditionally provided a consumer complaint function, and it is planning to devote greater portions of its resources to these efforts as a result of restructuring.

b. *State Government Agencies*. One or more state government agencies with similar consumer protection authority could take on additional duties. The Department of Consumer Affairs has been discussed. The Bureau of Weights and Measures might be appropriate supervisor of metering standards. The Department of Justice might be an appropriate entity for some activities. One advantage of non-CPUC agencies is that they would be received more favorably by municipal utilities who will have need of comparable consumer protection activities as they undergo their own version of restructuring in the future.

Chapter 13.

Monitoring and Oversight of Direct Access Implementation

13.1 Oversight of Implementation

13.1.1 CPUC Monitoring of Direct Access

Upon implementation of direct access, whether through a phase-in process or universal availability as of January 1, 1998, the CPUC should monitor implementation for a number of reasons. These include efforts to ensure that the Implementation Plan is properly followed; assessment of whether all the systems put into place as part of implementation are working properly and adequately; determination whether market participants are conducting themselves appropriately in accordance with the Policy Decision and the Implementation Plan; and, assuming a phase-in period of eligibility, assessment of the necessary length of the phase-in period.

Several parties believe that the Commission should act well before January 1, 1998, to establish a monitoring apparatus to advance these and any other monitoring goals. Whatever the form of that monitoring apparatus, these parties suggest that the CPUC issue a status report regarding implementation no less frequently than every six months. Such a report should be followed by a public comment period for stakeholders to state their agreement or disagreement with the Commission's assessment of implementation activities.

13.1.2 Verification That a Phase-in Schedule is Appropriate

As addressed in Section 13.1.1, one of the primary reasons for a monitoring apparatus is to verify that a phase-in period, if it occurs, is facilitating a smooth implementation of direct access transactions, and whether any adjustments to a phase-in schedule are appropriate. There is, however, no consensus that this monitoring of the phase-in is required, or that this monitoring must be performed by the CPUC.

Three alternatives exist for performing the phase-in monitoring:

<u>13.1.2.1 Alternative 1: The CPUC performs the monitoring.</u>

<u>13.1.2.2 Alternative 2: Some other entity, such as the ISO, performs the monitoring.</u>

<u>13.1.2.3. Alternative 3: No one performs the monitoring</u>

13.1.3 Options for Modification of Phase-in

If monitoring of the phase-in does occur, the entity performing the monitoring would have the option of proposing no changes, an acceleration of the phase-in or a lengthening of the phase-in period.

13.1.3.1 ALTERNATIVE: Possible Acceleration of Any Phase-In Period

Depending upon what the CPUC determines through its monitoring program, several parties believe that the CPUC should be in a position to accelerate the phase-in period for direct access eligibility if direct access implementation is proceeding smoothly. For example, if the various systems established to operate the ISO and PX, and to conduct billing activities, are not overly burdened by the initial subscription of direct access participants, the Commission may wish to broaden the availability of direct access earlier than may be initially scheduled under the Implementation Plan. The Commission may also wish to suggest changes in practice or procedure which would facilitate customer participation.

Alternative 13.1.3.1 PRO: Provides the CPUC with flexibility to modify its decisions regarding Direct Access implementation as more data on the process becomes available.

Alternative 13.1.3.1 CON: With any acceleration, impacts to infrastructure planning should be considered carefully to ensure equipment and systems will be in place. For planning purposes, making a decision on how best to proceed, and then establishing the fastest feasible schedule is preferable.

13.1.3.2 ALTERNATIVE: Possible Lengthening of Phase-In Period

The CPUC's monitoring program may lead to the conclusion that direct access implementation is not proceeding according to the Implementation Plan. In that circumstance, the CPUC may wish to assess whether steps should be taken to decelerate the implementation of direct access. Several parties believe, however, that in the event a phase-in schedule for direct access eligibility is extended, any customer who already has elected direct access should be permitted to maintain its eligibility.

Alternative 13.1.3.2 PRO: Provides the CPUC with flexibility to modify its decisions regarding Direct Access implementation as more data on the process becomes available.

Alternative 13.1.3.2 CON: A deceleration preventing participation to some will be unfair to those who as a result are excluded from direct access.

13.1.3.3 ALTERNATIVE: No Change to Phase-in Schedule

Alternative 13.1.3.3 PRO: Everyone knows the schedule and can plan accordingly.

Alternative 13.1.3.3 CON: None identified.

13.2 Recovery of UDC Implementation Costs

In Chapter 1 of this report, the key activities are identified which are necessary to permit direct access implementation to occur. They include: a) program design and regulatory approvals, (b) customer education and notification of participation, (c) customer-specific activities, (d) system verification prior to commencement, and (e) program operation and monitoring.

For each of these activities, there are likely to be cost burdens above and beyond the costs incurred under the current market structure which will affect the UDC, customers directly, and potential new market participants. The DAWG will not address the specific magnitude of implementation costs borne by new market participants, as it is assumed that third parties will seek cost recovery through market-based pricing rather than through regulatory mechanisms.

For UDCs and customers, however, different implementation alternatives have different cost implications, regarding both the magnitude of these costs as well as the means by which they will be recovered. This will impact the CPUC's policy decisions to the extent a balance must be struck between a policy objective and the costs of meeting that objective.

13.2.1 Identification of Appropriate Activities

Within the activities described in Chapter 1 are an array of functions which the UDC must perform or otherwise deploy investment capital to facilitate direct access implementation. They are outlined below:

13.2.1.1 Program Design and Regulatory Approvals

The activity with greatest cost in this category is the development of the Independent System Operator (ISO) and Power Exchange (PX) infrastructure. The costs of establishing the ISO and PX are still being developed. Current preliminary estimates are that the development of the ISO will cost $185 million and the development of the PX will cost $65 million. Once they are

functioning, each entity will reimburse the utilities for development costs and recover operating costs through their tariffs.

13.2.1.2 Customer Education and Notification of Participation

A number of UDC activities will be required to ensure that proper customer education and notification of participation is accomplished prior to direct access implementation. These include, but are not limited to: help in establishing an Independent Education Trust; specific UDC education efforts to supplement the Trust activities; augmentation of existing UDC customer service functions to address direct access inquiries, and administration of customer notification procedures. Cost estimates of these activities have yet to be developed.

13.2.1.3 Customer-Specific Activities

In Sections 3.2.5 and 8.5 of this report, there are two discussions critical to defining the nature and cost of customer-specific activities necessary for direct access implementation. Section 3.2.5 discusses the tradeoffs of allowing a load profile to be used in lieu of an hourly-interval meter for certain direct access customers. Section 8.5 discusses the various technology options for hourly interval meters.

The policy decisions and choice of technology regarding metering and communications for direct access will drive their cost impact on customers and on the UDCs. As indicated in section 8.5, the per-customer cost of installing hourly-interval meters ranges from $120 to $1,100 depending on the metering scenario. If load profiles are to be used for certain customers, then some parties believe there will be metering and data collection costs associated with establishing accurate load profiles. Other parties believe that the utilities' currently funded load research activities require only a modest or minor upgrading to establish even more accurate load profiles than currently exist. Also, some parties believe that existing load profile data can be further enhanced at relatively small cost by taking advantage of the extensive energy measurement data obtained by the UDCs in their DSM activities. These costs will vary depending on the degree of precision desired.

Data for direct access customers using an hourly-interval meter must be tracked hourly, which increases by several-hundred fold the data storage and processing requirements relative to today’s monthly collection of data by the UDC. The Commission has already determined that metering costs will be borne by consumers. However, it is likely that the UDCs will be required to fund in advance, without guarantee of future customer reimbursement, an increase of their data processing capabilities to some degree. The data storage and processing costs will vary depending on the direct access options available to the customer. The use of load profiles for aggregated customers would considerably reduce the data storage and processing costs.

13.2.1.4 Systems Verification Prior to Commencement

A number of hardware and software system installations are implied by the array of activities required for direct access implementation. Different technology applications are likely for metering and communications requirements, data processing and storage, billing, and customer service systems. These systems must be able to interact with each other and transfer information in a compatible format. It is possible that costs will be incurred by the UDCs to ensure that this compatibility is sufficient.

13.2.1.5 Program Operation and Monitoring

A number of activities will take place once direct access is in effect, beginning January 1, 1998, that will involve monitoring of the effectiveness of direct access transactions. The overall monitoring and evaluation function is likely to be a CPUC responsibility, but various monitoring activities, including the interaction between the UDC and the ISO, and the adequacy of customer education efforts, may impose costs on the UDCs.

13.2.2 Prudence and Recovery of Costs of Authorized Activities

To the extent the UDCs are authorized by the CPUC to perform direct access implementation activities, some mechanism should be in place to determine the prudence of UDC expenditures and the recovery mechanism for prudent costs.

13.2.2.1 ALTERNATIVE: Memorandum Accounts for each UDC

Memorandum accounts would be established for each UDC in connection with direct access implementation. The CPUC would review and approve the prudence of these costs under a formal proceeding. UDC recovery of these costs would be based on UDC-specific rate setting and CTC recovery mechanisms established in other proceedings.

Alternative 13.2.2.1 PRO: Addresses the fact that each UDC is likely to have different restructuring cost impacts. Also recognizes that the rate-setting and CTC recovery mechanisms may differ to some extent among the UDCs.

Alternative 13.2.2.1 CON: Unless these costs are recovered outside the Commissions established rate caps, and UDCs are assured of their recovery, UDCs will not adequately support restructuring initiatives. Assuming automatic recovery, even after passing a prudence review, does not work in a restructured environment.

13.2.2.2 ALTERNATIVE: Statewide Trust for UDC Implementation Costs

A trust would be established similar to that created to fund development of the ISO and PX. The UDCs would file a joint application seeking to establish a single tax exempt trust for direct access implementation costs.

Alternative 13.2.2.2 PRO: Uses the precedent established by the CPUC in establishing funding for other restructuring costs.

Alternative 13.2.2.2 CON: Direct access implementation costs are likely to differ for each UDC and, unlike development of the ISO and PX, will not necessarily be focused on a single activity affecting all UDCs.

Appendix A. List of DAWG Participants

Representatives from the following organizations attended at least one meeting of the Direct Access Working Group or its subgroups:

ABB Power T&D Company
Adams & Broadwell
Agricultural Energy Consumers Assoc.
Albers & Company
All Utilities Auditing Co.
American Wind Energy Association
APS
Association Of California Water Agencies
AT&T
Ater, Wynne, Hewitt, Dodson & Skerritt
Barkovich & Yap, Inc.
Barry F. McCarthy
BART
Brubaker & Assoc. Inc.
California City/County Street Light Association
California Energy Commission
California Farm Bureau
California Industrial Users
California Institute for Energy Efficiency
California Large Electric Consumers' Association
California League of Food Processors
California Manufacturers' Association
California Public Utilities Commission
California Retailers' Association
California-Nevada Community Action Assc.
Call Company
Calpine Corp.
Cellnet Data Systems
Center for Energy Efficiency & Renewable Technologies
City of Berkeley
City of El Paso
City of Palo Alto
City of San Jose
City of Santa Clara
CLFP for Pacific Coast Producer

Consumers Utility Brokerage
Crossborder, Inc.
CVE
De Cuir & Sumach
Department of Defense
Department of Navy
Department of Ratepayer Advocates
Department of Water Resources
Destec Energy, Inc.
Diablo Research Corp.
Duncan,Weinberg,Miller & Pembroke
Eastern Pacific Energy Corp.
Economic Sciences Corporation
Edison Electric Institute
Edison Mission Energy
El Paso Merchant Services
Electric Power Research Institute
EMI
Energy Mgmt. Svcs.
Energy Producers' & Users' Coalition
ENOVA
ENRON
FMY Associates, Inc.
Foster Associates
General Electric
Geothermal Energy Association
Golden State Mobile Home Owners' League
Graham & James for AECA
Grueneich Resource Advocates
Hansen McOuat Hamrin
Henwood Energy
HMH Resources Inc. for UC/DG-S
Hughes Electronics
Independent Energy Producers
Industrial Users Group
International Brotherhood of Electric Workers
International Power Technology
Interstate Gas Services, Inc.
ITRON
Jackson, Tufts, Cole & Black for CLECA
KJC Consulting Company
Knox Ricksen for NYMEX
Latino Issues Forum

Law Office of Richard L. Hamilton
Lawrence Berkeley Laboratory
Levy Associates
Little Hoover Commission
Los Angeles Department of Water Power
Luce, Forward, Hamilton & Scripps
Lucent Technologies
Marron, Reid & Sheehy
McDonnell Douglas
Merced Irrigation District
Mervyn's DHC
Metropolitan Water District of So.CA
Minasian, Minasian, Minasian, Spruance, Baber, Meith & Sores LLP
Mock Energy Management, LLC
Modesto Irrigation District
Morrison & Foerster LLP
Morse Richard Weisenmiller & Associates
MZA
National Electrical Manufacturers Assoc.
National Utility Service, Inc.
NCPA
New Energy Ventures, Inc.
New York Mercantile Exchange
Northrop Grumman
Northwest Power Planning Council
Pacific Bell
Pacific Corporation
Pacific Gas & Electric
PacifiCorps
Portland General Electric
Power Resource
Power Resources Mgrs.
PUC for DRA
Resource Management International, Inc.
Richard, Heath & Associates
Robinson-May for CRA
Rockwell Int.
Rumla Inc. for Powerex
Sacramento Municipal Utility District
Safeway, Inc.
Salt River Project
San Diego Gas & Electric
Schlumberger

Sierra Consulting Corp.
Sonoma County Water
Southern California Edison
Southern California Gas Company
Southern Electric Int.
SPURR
SRC
Strategic Energy Ltd.
Strategy Integration
Support Resource Inc.
Sutherland, Ashill & Brennan for CMA
Systems Integrated
The Utility Solutions Partnership, Inc.
THUMS Long Beach Co.
Toward Utility Rate Normalization
TRW
UCAN
University of California
Utility Design, Inc.
Utility Systems Corp.
Vail Research & Tech
Western Mobile Home Parkowners' Association
Wickland Power Services
Windward Consulting Services
Working Assets
Wright & Talisman
Xenergy Inc.

Appendix B. Schedule of DAWG Activities

The following is a list of the meetings and related activities of the full DAWG, the four technical committees formed to work on specific issues, the coordinating committee (CC) and the editing team (ET). All meeting were publicly noticed and open to the public. The CC was comprised of representatives from about ten entities participating in the DAWG process and was responsible for issues such as scheduling meetings, communicating with the CPUC and developing the format of the written report. The four technical committees were:

Team A	Implementation
Team B	Market Rules
Team C	Metering and Communications Systems
Team D	Consumer Education and Protection

Near the conclusion of the DAWG's discussion and drafting stage, a seven-person editing team (ET), representing six different participating entities, collaborated to develop an intermediate draft (August 19) and the present version of this Report.

Date	**Group/Activity**	**Location**
March 28	Letter to CPUC on behalf of 20 organizing parties	
April 5	Meeting of the organizing parties	San Francisco
April 17	DAWG	San Francisco
April 22	Scoping Workshop	CPUC
April 23	CC	CPUC
April 29	Teams A and C	San Francisco
April 30	Teams B and D	San Francisco
May 7	DAWG, CC	Los Angeles
May 16	Teams B and D	Sacramento
May 17	Teams A and C	Sacramento
May 30	Teams A and C	San Francisco
May 31	Teams B and D	San Francisco
June 5	Teams A and C	San Diego
June 6	Teams B and D	San Diego
June 7	DAWG, CC	San Diego
June 19	Teams B and D	Sacramento

Date	Group/Activity	Location
June 20	Teams A and C	Sacramento
June 21	Metering Workshop	Sacramento
July 1	Teams A and C, CC	Los Angeles
July 2	Teams B and D	Los Angeles
July 9	CC, DAWG, Checkpoint Meeting with Commissioners	CPUC
July 10	Teams A and C	San Francisco
July 11	Teams B and D	San Francisco
July 16	Teams A and C	San Diego
July 17	Teams B and D	San Diego
July 19	CC	Telephone Conference
August 1	DAWG - Collation and mailing of 1st Draft	Burbank
August 9	ET	Telephone Conference
August 13	ET	Telephone Conference
August 19	ET - Collation and mailing of 2nd Draft	Electronic transmission to Sacramento
August 23	DAWG Meeting with Editorial Team	Sacramento

Appendix C.

Concepts and Terms for Direct Access

This Appendix provides an example of a set of concepts, terms and definitions that might be useful to a discussion of Direct Access. Underlying this effort is the idea that electric industry restructuring comprises a new paradigm and requires a reinvestigation of the language used to describe electric service and prescribe appropriate policies. Because the terms and definitions given here were not discussed and agreed to by DAWG participants, the reader should not expect the usage in the text of this Report to be consistent with this Appendix.

For clarity of definition, the proposed terms are arranged in the first section by conceptual relatedness. The same terms are arranged alphabetically in the second section.

C.1 Table of Concepts

Electric Demand is the readiness, willingness, and ability to make use of Electric Energy, or the quantity which is demanded, at any given time; often averaged over a specific period of time, such as one hour, and is measured in Kilowatts.

Electric Energy is the capacity of doing work, in the form of an electric current, at some potential, for a given period of time, and is measured in Kilowatt-hours.

Electric Service Customers are *individual* persons or entities that manifest an ongoing **Electric Demand** of an individual character.

Electric Service Consumers are *typical* persons or entities that manifest an ongoing **Electric Demand** of a typical character.

Utility Customers are any **Electric Service Customers** receiving *any* portion of their **Electric Service** from the **Utility**.

Non-utility Customers are any **Customers** receiving *any* portion of their **Electric Service** from a **Non-utility Provider**.

End-use Customers are **Customers** whose **Demand** arises in consumption rather than in remarketing.

Direct Customers are **End-use Customers** receiving **Electric Service** *directly* from **Generators**, without the services of **Intermediate Providers**.

Bilateral Contract Customers are **Direct Customers**.

Retail Customers are **End-use Customers** receiving **Electric Service** from an **Intermediate Provider**.

Intermediate Customers are **Customers** whose **Demand** arises in remarketing, rather than in consumption.

Actual Customers are persons or entities that actually have a **Demand**.

Nominal Customers are persons or entities in whose name **Electric Service** has been requested, a **Transaction** has been consummated, or an **Account** is registered.

Electric Service is the ongoing performance of various works which satisfies the **Demand** of **Customers** for **Electric Service**.

Utility Electric Service, or **UES**, is the provision of **Electric Service** by the local **Utility**.

Utility Service, not otherwise specified, is **Utility Distribution Service**.

Non-utility Electric Service is the provision of **Electric Service** by a **Non-utility Electric Service Provider**.

Other Kinds of Service:

Energy Service is **Service** provided at **Customer Premises** to reduce, or control the load profile of, **Electric Service**.

Energy Conservation Service is **Energy Service** to reduce the absolute **Demand** arising from a particular use.

Electric Load Management Service is **Energy Service** to optimize a **Load Profile**.

On-Site Generation Service is **Energy Service** to reduce the actual **Electric Service** required by a given **Demand**.

Generation Service is the **Service** of physically producing **Electric Energy**.

Transmission Service is **Service** of coordinating and physically delivering **Electric Energy**, under federal-regulation, over the interstate Transmission System; in California, provided by the **ISO**.

Distribution Service. See **Local Transmission and Distribution Service**.

Local Transmission and Distribution Service is the **Service** of providing the plant and operations for the physical delivery of **Electric Energy** from the Transmission System by the UDC to its Distribution Customers over state-regulated Local Transmission and Distribution System.

Ancillary Services are various **Services** required to maintain the **Stability** of the **Electric System**.

Operations are the functional activities undertaken by a **Provider** by which **Service** is accomplished.

Administrative Operations, or **Administration**, is the body of functions undertaken by a **Provider** to establish, maintain, or alter its status as a business entity.

Production Operations, or **Operations**, is the body of functions undertaken by a **Provider** to effectively design or efficiently reproduce its product or **Service**.

Installation is the placement of **Equipment** in service at a premises.

Maintenance is the care and repair of any **Facilities**.

Marketing Operations, or **Marketing**, is the body of functions undertaken by a **Provider** to establish, maintain, or alter its relationships with actual or potential **Customers**.

Customer Operations are the functions undertaken to identify actual and potential **Customers** and to promote the identity of the **Provider**.

Terms and Conditions are the operable provisions of any **Tariff** or **Contract** for **Service**.

Bilateral Contract means the agreement by which a **Customer** receives any portion of its **Electric Service** directly from a **Generator**.

Revenue Operations, sometimes identified as order-billing operations, are the functions undertaken to document performance of the **Terms and Conditions** of **Service**.

Billing is the operation wherein current **Electric Service** is invoiced to the **Customer** for payment and prior payments are acknowledged.

Billing Entity means the entity which exercises **Control** over the **Billing** process, whether or not it actually performs the operations.

Billing Operator means the entity which actually performs **Billing Operations**, whether on its own behalf or on the behalf of another entity.

Rate Operations are the functions undertaken to communicate the **Prices** or **Quantities** of **Service**.

Metering is the operation wherein **Usage Quantities** are detected, measured, and registered.

Pricing is any scheme of establishing the **Price** for any **Service Commodities**.

Automatic Meter Reading, or **AMR**, is any mode of **Meter** reading that is technologically-enhanced or otherwise not fully manual; unless otherwise noted, it refers only to full-automated systems in this report.

Service Operations are the functions undertaken to physically enable, reconfigure, or disable **Service**.

Transactions are the specific exchanges that occur between a **Provider** and a **Customer** by which **Marketing** is accomplished.

Market Transactions are exchanges of **Customer**- or **Provider**-specific information concerning the provider-customer relationship.

Revenue Transactions are exchanges of performance of the **Terms and Conditions** of **Service**.

Billing Period means the interval over which **Electric Service** is provided and periodically invoiced.

Billing Quantities are the amounts of **Service Commodities** invoiced to the **Customer** under a single **Statement** of a **Billing Account**.

Conjunctive Billing means the summation of **Service Quantities** provided and **Payments** due or paid for two or more **Rate Accounts** for invoicing to a **Customer** under a single **Bill**.

Rate Transactions are exchanges of data concerning the **Prices** or **Quantities** of **Service**.

Price means the dollar amount for which a given **Service Commodity** is sold under any specific circumstances.

Settlement Period means the time period during which ISO and PX operations are cleared; currently, one clock hour.

Rate means the schedule of **Prices** applying to the **Billing Quantities** of the various **Service Commodities** of **Electric Service,** and other services.

Load Profiling is any method of *estimating* **Usage Quantities** for a more-time-specific **Pricing** or **Billing** scheme from the **Meter Quantities** of a less-time-specific **Metering** scheme; specifically, any method of estimating **Real-time** Usage Quantities from **Average Use** Meter Quantities.

Service Transactions are interactions with the **Customer**, or the Customer's **Premises**, that physically enable, reconfigure, or disable **Service**.

Service Commodities are any of the specific, characteristic components of **Electric Service**: **Electric Energy** delivered (KWH), **Electric Capacity** (KVA or HP) or **Electric Demand** (KW) accommodated, or **Accounts** (each) serviced, which may be further specified by a time period or other characteristics.

Accounts are records of **Transactions**.

Customer Account means the body of all of the **Market Transactions** involved in the relationship between a specific **Customer** and a specific **Provider**, including one or more **Billing Accounts**

Billing Account means the body of all of the **Revenue Transactions** for **Electric Service** under specific **Terms and Conditions (**as under a specific **Tariff** or **Contract)**, as determined under one or more **Rate Accounts**.

Rate Account means the body of all of the **Rate Transactions** for **Electric Service** under a specific **Rate Schedule**, as determined from one or more **Meter Accounts**.

Meter Account means the body of all of the **Service Transactions** for **Electric Service** via a specific **Meter Point**.

Statements are any communication of **Account** information

Bills are **Statements** of **Billing Account** information.

Rate Calculations are **Statements** of **Rate Account** information.

Facilities are the assets, generally, used by **Providers** to perform **Operations** or by either **Customers** or **Providers** to engage in **Transactions**.

Market Facilities are to be understood as any property, equipment, or other assets for provider-customer interaction.

Revenue Facilities are any property, equipment, or other assets for documenting performance of the **Terms and Conditions** of **Service**.

Rate Facilities, including data communications systems, are any property, equipment, or other assets for communicating the **Prices** or **Quantities** of **Service**.

Service Facilities are to be understood as any property, equipment, or other assets to physically enable, reconfigure, or disable Service.

Service Line is the customer-specific electrical conductors connecting the customer's premises to the UDC's distribution grid. A service lateral is an underground service line; a service drop is an overhead service line.

Meter Socket the equipment which holds the meter and provides electrical contacts to the parts of the electrical circuit or any attached transformers appropriate to the operation of that meter.

Meter is to be understood as the equipment by which the delivery of electric energy is detected, measured, and registered.

Electric Service Industry is the institutional setting in which adequate **Facilities**, fair **Transactions**, and reasonable **Service** is established and maintained.

Generators are entities having the capability of physically producing **Electric Energy**.

Self-Generator is a **Generator** for one's own **Demand**.

Supply Generator is a **Generator** for the **Demand** of others.

Electric System, or **Grid**, is the entire **Transmission** and **Distribution** network, together with **Generators** and **Customer's Premises**, considered as a single, interconnected network.

Electric Service Providers are the specific entities within the **Electric Service Industry**, which provide the **Facilities**, the **Operations**, the **Transactions**, and the **Services**, or otherwise satisfy the **Demands** of **Customers** for **Electric Service**.

Utility Electric Service Providers, or **Utility ESPs**, are **UDCs** in their role as **ESPs** within their own **Service Territory**, or the operating subdivisions of the **Utility** providing **Electric Service**, as distinguished from the operating subdivisions providing **Distribution Service**.

Utility Distribution Companies, or **UDCs**, are the entities providing **Local Transmission and Distribution Service** in particular **Service Territories** under authority of the **CPUC** and **Franchise Authorities**.

Utilities are **Utility Distribution Companies**.

Non-utility Electric Service Providers, or **Non-utility ESPs**, are **ESPs** that are not the local **Utility**.

Direct Providers are **Generators** providing **Service** directly to **End-use Customers**.

Bilateral Contract Providers are **Direct Providers**.

Intermediary Providers are **Non-utility ESPs** providing **Electric Service** that is generated by others.

Retail Electric Service Providers, or **Retailers**, are **Intermediate Providers** of **Services** to **End-use Customers**.

Aggregators are **Retail ESPs**.

ESP is an abbreviation for any **Electric Service Provider**.

C.2 Alphabetical Glossary of Terms

Accounts are records of **Transactions**.
Actual Customers are persons or entities that actually have a **Demand**.
Administrative Operations, or **Administration**, is the body of functions undertaken by a **Provider** to establish, maintain, or alter its status as a business entity.
Aggregators are **Retail ESPs**.
Ancillary Services are various **Services** required to maintain the **Stability** of the **Electric System**.
Automatic Meter Reading, or **AMR**, is any mode of **Meter** reading that is technologically-enhanced or otherwise not fully manual; unless otherwise noted, it refers only to full-automated systems in this report.

Bilateral Contract Customers are **Direct Customers.**
Bilateral Contract means the agreement by which a **Customer** receives any portion of its **Electric Service** directly from a **Generator**.
Bilateral Contract Providers are **Direct Providers**.
Billing Account means the body of all of the **Revenue Transactions** for **Electric Service** under specific **Terms and Conditions (**as under a specific **Tariff** or **Contract)**, as determined under one or more **Rate Accounts**.
Billing Entity means the entity which exercises **Control** over the **Billing** process, whether or not it actually performs the operations.
Billing is the operation wherein current **Electric Service** is invoiced to the **Customer** for payment and prior payments are acknowledged.
Billing Operator means the entity which actually performs **Billing Operations**, whether on its own behalf or on the behalf of another entity.
Billing Period means the interval over which **Electric Service** is provided and periodically invoiced.
Billing Quantities are the amounts of **Service Commodities** invoiced to the **Customer** under a single **Statement** of a **Billing Account**.
Bills are **Statements** of **Billing Account** information.

Conjunctive Billing means the summation of **Service Quantities** provided and **Payments** due or paid for two or more **Rate Accounts** for invoicing to a **Customer** under a single **Bill**.
Customer Account means the body of all of the **Market Transactions** involved in the relationship between a specific **Customer** and a specific **Provider**, including one or more **Billing Accounts**
Customer Operations are the functions undertaken to identify actual and potential **Customers** and to promote the identity of the **Provider**.

Direct Customers are **End-use Customers** receiving **Electric Service** *directly* from **Generators**, without the services of **Intermediate Providers**.
Direct Providers are **Generators** providing **Service** directly to **End-use Customers**.
Distribution Service. See **Local Transmission and Distribution Service**.

Electric Demand is the readiness, willingness, and ability to make use of Electric Energy, or the quantity which is demanded, at any given time; often averaged over a specific period of time, such as one hour, and is measured in Kilowatts.
Electric Energy is the capacity of doing work, in the form of an electric current, at some potential, for a given period of time, and is measured in Kilowatt-hours.
Electric Load Management Service is **Energy Service** to optimize a **Load Profile**.
Electric Service Consumers are *typical* persons or entities that manifest an ongoing **Electric Demand** of a typical character.
Electric Service Customers are *individual* persons or entities that manifest an ongoing **Electric Demand** of an individual character.
Electric Service Industry is the institutional setting in which adequate **Facilities**, fair **Transactions**, and reasonable **Service** is established and maintained.
Electric Service is the ongoing performance of various works which satisfies the **Demand** of **Customers** for **Electric Service**.
Electric Service Providers are the specific entities within the **Electric Service Industry**, which provide the **Facilities**, the **Operations**, the **Transactions**, and the **Services**, or otherwise satisfy the **Demands** of **Customers** for **Electric Service**.
Electric System, or **Grid**, is the entire **Transmission** and **Distribution** network, together with **Generators** and **Customer's Premises**, considered as a single, interconnected network.
End-use Customers are **Customers** whose Demand arises in consumption rather than in remarketing.
Energy Conservation Service is **Energy Service** to reduce the absolute **Demand** arising from a particular use.
Energy Service is **Service** provided at **Customer Premises** to reduce, or control the load profile of, **Electric Service**.
ESP is an abbreviation for any **Electric Service Provider**.

Facilities are the assets, generally, used by **Providers** to perform **Operations** or by either **Customers** or **Providers** to engage in **Transactions**.

Generation Service is the **Service** of physically producing **Electric Energy**.
Generators are entities having the capability of physically producing **Electric Energy**.

Installation is the placement of **Equipment** in service at a premises.
Intermediary Providers are **Non-utility ESPs** providing **Electric Service** that is generated by others.
Intermediate Customers are **Customers** whose **Demand** arises in remarketing, rather than in consumption.

Load Profiling is any method of *estimating* **Usage Quantities** for a more-time-specific **Pricing** or **Billing** scheme from the **Meter Quantities** of a less-time-specific **Metering** scheme; specifically, any method of estimating **Real-time** Usage Quantities from **Average Use** Meter Quantities.
Local Transmission and Distribution Service is the **Service** of providing the plant and operations for the physical delivery of **Electric Energy** from the Transmission System by the UDC to its Distribution Customers over state-regulated Local Transmission and Distribution System.

Maintenance is the care and repair of any **Facilities**.
Market Facilities are to be understood as any property, equipment, or other assets for provider-customer interaction.
Market Operations are the functions undertaken to create, identify, or alter relationships with individual **Customers** or specified groups of customers.
Market Transactions are exchanges of **Customer**- or **Provider**-specific information concerning the provider-customer relationship.
Marketing Operations, or **Marketing**, is the body of functions undertaken by a **Provider** to establish, maintain, or alter its relationships with actual or potential **Customers**.
Meter Account means the body of all of the **Service Transactions** for **Electric Service** via a specific **Meter Point**.
Meter is to be understood as the equipment by which the delivery of electric energy is detected, measured, and registered.
Meter Socket the equipment which holds the meter and provides electrical contacts to the parts of the electrical circuit or any attached transformers appropriate to the operation of that meter.
Metering is the operation wherein **Usage Quantities** are detected, measured, and registered.

Nominal Customers are persons or entities in whose name **Electric Service** has been requested, a **Transaction** has been consummated, or an **Account** is registered.
Non-utility Customers are any **Customers** receiving *any* portion of their **Electric Service** from a **Non-utility Provider**.
Non-utility Electric Service is the provision of **Electric Service** by a **Non-utility Electric Service Provider**.
Non-utility Electric Service Providers, or **Non-utility ESPs**, are **ESPs** that are not the local **Utility**.

On-Site Generation Service is **Energy Service** to reduce the actual **Electric Service** required by a given **Demand**.
Operations are the functional activities undertaken by a **Provider** by which **Service** is accomplished.

Price means the dollar amount for which a given **Service Commodity** is sold under any specific circumstances.

Pricing is any scheme of establishing the **Price** for any **Service Commodities**.
Production Operations, or **Operations**, is the body of functions undertaken by a **Provider** to effectively design or efficiently reproduce its product or **Service**.

Rate Account means the body of all of the **Rate Transactions** for **Electric Service** under a specific **Rate Schedule**, as determined from one or more **Meter Accounts**.
Rate Calculations are **Statements** of **Rate Account** information.
Rate Facilities, including data communications systems, are any property, equipment, or other assets for communicating the **Prices** or **Quantities** of **Service**.
Rate means the schedule of **Prices** applying to the **Billing Quantities** of the various **Service Commodities** of **Electric Service,** and other services.
Rate Operations are the functions undertaken to communicate the **Prices** or **Quantities** of **Service**.
Rate Transactions are exchanges of data concerning the **Prices** or **Quantities** of **Service**.
Retail Customers are **End-use Customers** receiving **Electric Service** from an **Intermediate Provider**.
Retail Electric Service Providers, or **Retailers**, are **Intermediate Providers** of **Services** to **End-use Customers**.
Revenue Facilities are any property, equipment, or other assets for documenting performance of the **Terms and Conditions** of **Service**.
Revenue Operations, sometimes identified as order-billing operations, are the functions undertaken to document performance of the **Terms and Conditions** of **Service**.
Revenue Transactions are exchanges of performance of the **Terms and Conditions** of **Service**.

Self-Generator is a **Generator** for one's own **Demand**.
Service Commodities are any of the specific, characteristic components of **Electric Service**: **Electric Energy** delivered (KWH), **Electric Capacity** (KVA or HP) or **Electric Demand** (KW) accommodated, or **Accounts** (each) serviced, which may be further specified by a time period or other characteristics.
Service Facilities are to be understood as any property, equipment, or other assets to physically enable, reconfigure, or disable Service.
Service Line is the customer-specific electrical conductors connecting the customer's premises to the UDC's distribution grid. A service lateral is an underground service line; a service drop is an overhead service line.
Service Operations are the functions undertaken to physically enable, reconfigure, or disable **Service**.
Service Transactions are interactions with the **Customer**, or the Customer's **Premises**, that physically enable, reconfigure, or disable **Service**.
Settlement Period means the time period during which ISO and PX operations are cleared; currently, one clock hour.
Statements are any communication of **Account** information
Supply Generator is a **Generator** for the **Demand** of others.

Terms and Conditions are the operable provisions of any **Tariff** or **Contract** for **Service**.
Transactions are the specific exchanges that occur between a **Provider** and a **Customer** by which **Marketing** is accomplished.
Transmission Service is **Service** of coordinating and physically delivering **Electric Energy**, under federal-regulation, over the interstate Transmission System; in California, provided by the **ISO**.

Utilities are **Utility Distribution Companies**.
Utility Customers are any **Electric Service Customers** receiving *any* portion of their **Electric Service** from the **Utility**.
Utility Distribution Companies, or **UDCs**, are the entities providing **Local Transmission and Distribution Service** in particular **Service Territories** under authority of the **CPUC** and **Franchise Authorities**.
Utility Electric Service Providers, or **Utility ESPs**, are **UDCs** in their role as **ESPs** within their own **Service Territory**, or the operating subdivisions of the **Utility** providing **Electric Service**, as distinguished from the operating subdivisions providing **Distribution Service**.
Utility Electric Service, or **UES**, is the provision of **Electric Service** by the local **Utility**.
Utility Service, not otherwise specified, is **Utility Distribution Service**.

Appendix D.

Supplementary Material on Market Rules

Contents of Appendix D

D.1 Areas of possible P. U. Code exemptions for competitive retailers.
D.2 CPUC Regulation of Telecommunication Service Providers
D.3 California Statutes Applicable to Competitive Energy Service Retailers
D.4 Rules for Competitive Energy Providers in Other States
D.5 Proposed Code of Conduct to Govern Retail Electric Service Transactions

D.1 Areas of possible P. U. Code exemptions for competitive retailers.

The following provisions of the California Public Utilities Code should probably not apply to the privately-owned retail generation sector. This list is not intended to be exhaustive.

§ 454: Rate change process requiring CPUC approval prior to changing rates
§ 454.3 et seq.: Special rate of return statutes
§ 455: Authorizes hearings on filed rate schedules
§ 455.5: Authorizes CPUC to disallow rate of return for out-of-use facility
§ 456: Allows utilities to earn extra profits for efficiencies
§ 457: Permits sliding scale of charges
§ 463: CPUC may disallow utility recovery in rates for bad planning and unreasonable costs
§ 489-494: Tariff filings
§ 532: Compliance with tariff filings
§ 612: Power of eminent domain
§ 816 et seq.: Special corporate requirements

Discussion of § 612, *Power of Eminent Domain*.

Eminent domain is the power to take private property for a necessary public purpose on payment of just compensation. The right to take property by eminent domain cannot be created, or used, to compel the sale or property for a private use, even if there are public benefits to such use. Private industries, i.e. industries operated for the benefit of the owners, generally must

acquire property through the open market. Generation companies owned by, and operated for the benefit of, their shareholders, should not have the right of eminent domain.

This issue would be fairly uncomplicated if the ownership of generation were entirely separate from the ownership of transmission and distribution. Transmission and at least some portion of the distribution function will remain regulated monopoly services. Thus the right of eminent domain should continue to be available for transmission and distribution enlargements.

Independent energy producers are concerned, however, that transmission owning utilities that also own competitive generation services could use their right of eminent domain to unfairly enhance the transmission system in a manner that enhances the competitive advantage of their generation while refusing to undertake enhancements that would benefit non-utility generation.

Existing law does provide some protection. First, the right of eminent domain is not absolute: the taking of private property must be necessary for a public purpose. The defendant in a condemnation action (the private property owner) can challenge the proposed taking on certain grounds including whether the purpose for the taking is a genuine public purpose. The eminent domain law does not appear to allow other interested persons to challenge the taking, however.

Second, § 211 of the Federal Power Act permits any "electric utility" to apply to FERC for an order requiring a transmission-owning utility to "to provide transmission services (including any enlargement of transmission capacity necessary to provide such services)." 16 U.S.C. § 824j. "Electric utility" is broadly defined to include "any person or State agency which sells electricity." 16 U.S.C. § 796(22). This option is expensive (over-and-above the cost of improvement) and time-consuming to pursue (transmission-owning utilities can drag their heels).

Possible measures to make the process for transmission improvements more fair and efficient include:

1. Complete divestiture. If transmission-owning utilities completely divested themselves of all generation, they would no longer have any incentive to develop enhancements to the transmission system to benefit (only) their generation. Nor would they have any incentive not to cooperate with other parties' transmission enhancement projects.

2. Prior review of eminent domain purchases. One means for ensuring that transmission-owning utilities do not exercise their eminent domain powers in discriminatory fashion is to require the utility to demonstrate the public interest of the proposed purchase to a state regulatory body such as the CPUC first, regardless of whether the purchaser intends to challenge the taking. (Often the only thing the property owner challenges is the element of "just compensation.")

3. An expedited FERC process for enlargements in transmission capacity. Construction of new transmission in the best circumstances requires time, and thus constitutes a barrier to entry for new generation. The processes for obtaining a FERC order to require an unwilling transmission-

owning utility to construct improvements, or to determine cost apportionments between the applicant and the transmission owner, should be as short and inexpensive as possible. At present, the WEPEX parties are working on details of a process whereby the ISO would be involved in identifying the need for transmission system upgrades and expansion.

D.2 CPUC Regulation of Telecommunication Service Providers

[See text Section 6.2.2.] The rules specified in CPUC Decisions D. 95-07-054 (Appendices A and B) and D. 95-12-056 (Appendix C) govern the activities of competitive local carriers (CLCs), local telephone service providers that need not own or operate any telephone service facilities. The rules can be divided into two main categories: pricing and business practices, and consumer protection. The following items are some excerpts taken verbatim from the decisions. [Letters or numbers on the items are those from the original sources.]

D.2.1 Rules Governing Pricing and Business Practices

E. CLCs shall be subject to the following tariff and contract filing, revision and service pricing standards:

(2) Uniform major rate increases for existing tariff services shall become effective on thirty (30) days' notice to the Commission, and shall require bill inserts, or a message on the bill itself, or first class mail notice to customers at least 30 days in advance of the pending rate increase.

(3) Uniform minor rate increases shall become effective on not less than five (5) working days' notice to the Commission. Customer notification is not required for such minor rate increases.

F. The following regulations shall apply to CLCs:

(1) CLCs shall be required to serve customers requesting service within their designated service territory on a nondiscriminatory basis, but shall not be required to have the same service territory as LEC service territories.

(2) Facilities-based CLCs shall at a minimum serve all customers who request service and whose premises are within 300 feet of the CLC's transmission facilities used to provide service so long as the CLC can reasonably obtain access to the point of demarcation on the customer's premises, but the CLC shall not be required to build out facilities beyond such 300 feet.

(7) CLCs shall be subject to the obligations of public utilities under the PU Code including but not limited to, § 451 and 453, dealing with the provision of just and reasonable rates and charges.

(8) CLCs must obtain Commission approval before discontinuing service in any part of their service area.

(9) CLCs shall provide E-911 service.

(10) To ensure that qualified customers are provided with telecommunication devices for the deaf (TDDs) or other telecommunication equipment under the Deaf and Disabled Telecommunications Program (DDTP) program:

(a) CLCs should contract with Pacific Bell, GTE of California, the California Telephone Association or Thomson Consulting to offer equipment and services to eligible deaf and disabled customers. These contracts should be interim pending the outcome of continued workshops to determine how CLCs should participate in the DDTP over the long term.
(b) CLCs shall specify in their tariffs how they will offer DDTP services.

(11) CLCs shall respond promptly to their customer's 611 repair calls by either using their own service technicians or through contractual arrangements. The CLC shall disclose the procedure for ordering repair service at the time the customer initiates service as well as on the monthly customer bill.

(a) LECs shall institute a referral system to direct CLC customers who dial "611" to the appropriate CLC for service or to the Commission's Consumer Affairs Branch if the CLC's identity is unknown.
(b) CLCs shall institute a similar referral system to direct calls of other competitor's customers seeking repair service.

(12) CLCs shall be subject to the consumer protection rules contained in Appendix B of D.95-07-054. [Summarized in Section 7.1.2.3.2 below.]

(13) CLCs shall provide the following reports to the Commission:

(a) On a quarterly basis, a copy of all written notices provided to customers, in accordance with Rules 1, 2 and 6 of the consumer protection rules set forth in Appendix B;
(b) By April 1 of each year a copy of the CLC's annual report;
(c) On a monthly basis, reports regarding major service outages; ...

(14) CLCs shall submit all mandated bill insert notices, including notices of basic universal service rate increases, to the Commission's Public Advisor's Office for review and approval, and shall allow the Public Advisor's Office at least five working days to review and approve the proposed bill inserts prior to their issuance to customers.

(15) CLCs shall deposit customer deposits in a protected, segregated, interest-bearing escrow account subject to Commission oversight.

(16) CLCs shall inform each new customer, in writing and in the language in which the sale was made, of the availability, terms, and statewide rates of Universal Lifeline Telephone Service and basic service. CLCs shall also provide bills, notices, and access to bilingual customer service representatives in the languages in which prior sales were made.

(17) Redlining is prohibited and the Commission shall take strong action against any carrier engaging in redlining.

D.2.2 Rules Governing Consumer Protection

Excerpts from D. 95-07-054, Appendix B
Consumer Protection and Consumer Information Rules for CLCs

These Consumer Protection Regulations apply to CLCs and, where noted, to LECs.

2.3 INFORMAL COMPLAINT

Informal request for assistance made to the Commission's Consumer Affairs Branch (CAB) with supporting documentation concerning a CLC's service, rates or other matters. CAB staff investigates and tries to arrive at an informal adjustment without public hearing or Commission order. Informal complaint files are not available for public inspection.

2.4 FORMAL COMPLAINT

A formal charge that a CLC has violated the Public Utilities Code or some order or regulation of the Commission. The complaint must be in writing, be in accordance with the Commission's Rules of Practice and Procedure and made under oath. The proceeding ordinarily requires public hearing and a Commission decision.

3.0 RULES

RULE 1 - CLC INFORMATION

CLCs shall, on request, provide each applicant for service or customer the following:

A. The California Public Utilities Commission identification number of its registration to operate as a telecommunications corporation within California.
B. The address and telephone number of the California Public Utilities Commission to verify its authority to operate.
C. A copy of these Consumer Protection Regulations.

D. A toll-free number to call for service or billing inquiries, along with an address where the customer may write the CLC.
E. A full disclosure of all fictitious i.e., dba names.
F. The names of billing agents it uses in place of performing the billing function itself.
G. Rate information as required by Rule 6(A).

RULE 2 - INITIATION OF SERVICE

During the initial contact all applicants for residential service must be given information regarding the Universal Lifeline program and its availability.

Service may be initiated based on a written or oral agreement between the CLC and the customer. In either case, prior to the agreement, the customer shall be informed of all rates and charges for the services the customer desires and any other rates or charges which will appear on the customer's first bill.

If the agreement is oral, within 10 days of initiating the service order, the CLC will provide a confirmation letter setting forth a brief description of the services ordered and itemizing all charges which will appear on the customer's bill. The letter must be in a language other than English if the sale was in another language.

Within 10 days of initiating service, the CLC shall state in writing for all new customers all material terms and conditions that could affect what the customer pays for telecommunications services provided by the CLC.

Potential customers who are denied service for failure to establish credit or pay deposit as described in Rule 12 must be given the reason for the denial in writing within 10 days of service denial.

RULE 3 - SPECIAL INFORMATION REQUIRED ON FORMS

A. Customer Bills

The CLC shall be identified on each bill. Each bill must prominently display a toll-free number for service or billing inquiries, along with an address where the customer may write. If the CLC uses a billing agent, the carrier must also include the name of the billing agent it uses. Each bill for telephone service will contain notations concerning the following areas:

(1) When to pay your bill;
(2) Billing detail including the period of service covered by the bill;
(3) Late payment charge and when applied;
(4) How to pay your bill;
(5) Questions about your bill;

(6) Network access for interstate calling;
(7) In addition to the above, each bill shall include the following statement: [Deals with payment due date, late payment charge, how to make inquiries, how to file a complaint.]

B. Deposit Receipts

Each deposit receipt shall contain the following provisions:

"This deposit, less the amount of any unpaid bills for service furnished by (name of CLC), shall be refunded, together with any interest due, within 30 calendar days after the discontinuance of service, or after 12 months of service, whichever comes first. However, deposits may not receive interest if the customer has received a minimum of two notices of discontinuance of service for nonpayment of bills in a 12-month period.

RULE 4 - CREDIT ESTABLISHMENT

Each applicant for service shall provide credit information satisfactory to the CLC or pay a deposit. Deposits shall not be required if the applicant:

A. Provides credit history acceptable to the CLC. Credit information contained in the applicant's account record may include, but shall not be limited to, account established date, "can-be-reached" number, name of employer, employer's address, customer's driver*s license number or other acceptable personal identification, billing name, and location of current and previous service. Credit cannot be denied for failure to provide social security number.

B. A cosigner or guarantor may be used providing the cosigner or guarantor has acceptable credit history with the serving CLC or another acceptable local carrier.

C. A CLC cannot refuse a deposit to establish credit for service. However, it may request the deposit to be in cash or other acceptable form of payment (e.g., cashier's check, money order, bond, letter of credit).

RULE 5 - DEPOSITS

In the event the customer fails to establish a satisfactory credit history, deposits are a form of security that shall be required from customers to ensure payment of bills.

Deposits shall be no greater than twice the estimated average monthly bill for the class of service applied for.

In the event a customer requests services in addition to basic service, the average bill will reflect the aggregate services requested by the customer. Deposits will be refunded with interest within

30 days after discontinuance of service or after 12 months of service, whichever comes first. Interest will be added to the deposit using the 3-month commercial paper rate published by the Federal Reserve Board, except under the following conditions: no interest shall be given if the customer has received a minimum of two notices in a 12-month period as provided under Rule No. 6(B)(2).

RULE 6 - NOTICES

Notices provided to the customer by the CLC shall be as follows:

A. Rate Information
B. Discontinuance of Service Notice

Notices to discontinue service for nonpayment of bills shall be provided in writing by first class mail to the customer not less than 7 calendar days prior to termination. Each notice shall include all of the following information:

1. The name and address of the customer whose account is delinquent.
2. The amount that is delinquent.
3. The date when payment or arrangements for payment are required in order to avoid termination.
4. The procedure the customer may use to initiate a complaint or to request an investigation concerning service or charges.
5. The procedure the customer may use to request amortization of the unpaid charges.
6. The telephone number of a representative of the CLC, who can provide additional information or institute arrangements for payment.
7. The telephone number of the Commission's Consumer Affairs Branch (CAB) where the customer may direct inquiries.
8. Local service may not be discontinued for nonpayment of Category III or other unregulated competitive services.

C. Change in Ownership or Identity Notice

CLCs shall notify their customers in writing of a change in ownership or identity of the customer's service provider on the customers' next monthly billing cycle.

D. Rules for CLC Notices

Notices the CLC sends to customers, or the Commission, shall be a legible size and printed in a minimum point size type of 10 and are deemed made on date of presentation (Sec. 2.7).

RULE 8 - DISPUTED BILLS

In case of a billing dispute between the customer and the CLC as to the correct amount of a bill, which cannot be adjusted with mutual satisfaction, the customer can make the following arrangement:

A. First, the customer may make a request, and the CLC will comply with the request, for an investigation and review of the disputed amount.

B. The undisputed portion of the bill must be paid by the Due By Date (No sooner than 15 days of the date of presentation) shown on the bill or the service will be subject to disconnection if the CLC has notified the customer by written notice of such delinquency and impending termination.

C. If there is still disagreement after the investigation and review by a manager of the CLC, the customer may appeal to CAB for its investigation and decision. To avoid disconnection of service, the customer must submit the claim and, if the bill has not be paid, deposit the amount in dispute with CAB within 7 calendar days after the date the CLC notifies the customer that the investigation and review are completed and that such deposit must be made or service will be interrupted. However, the service will not be disconnected prior to the Due By Date shown on the bill.

D. The CLC may not disconnect the customer's service for nonpayment as long as the customer complies with (B) and (C) above.

E. The CLC shall respond to CAB's requests for information within 10 business days.

F. CAB will review the claim of the disputed amount, communicate the results of its review to the customer and CLC and make disbursement of the deposited amount.

G. After the investigation and review are completed by the CLC as noted in (A) above, if the customer elects not to deposit the amount in dispute with CAB, such amount becomes due and payable at once. In order to avoid disconnection of service, such amount must be paid within 7 calendar days after the date the CLC notifies the customer that the investigation and review are completed and that such payment must be made or service will be interrupted. However, the service will not be disconnected prior to the Due By Date shown on the bill.

RULE 10 - DISCONTINUANCE OF SERVICE

A. Service may be discontinued for nonpayment of bills provided:

1. The bill has not been paid by the due date shown on the bill.
2. Notice of the proposed discontinuance is provided pursuant to Rule 6(B)(2).
3. Service is not initially discontinued on any Saturday, Sunday, legal holiday, or any other day CLC service representatives are not available to serve customers.

B. Fraud

The CLC shall have the right to refuse or discontinue service without advance notice if the acts of the customer are such as to indicate intention to defraud the CLC. This includes fraudulently placing and receiving calls and/or providing false credit information.

C. For residence services disconnected for nonpayment, the CLC must continue to provide access to 911 services to the customer.

RULE 11 - CHANGE OF SERVICE PROVIDER

A. Solicitation of customer authorization for service termination and transfer.

Solicitations by LECs, CLCs, or their agents, of customer authorization for termination of service with an existing carrier and the subsequent transfer to a new carrier must include current rate information on the new carrier and information regarding the terms and conditions of service with the new carrier. Solicitations by LECs, CLCs, or their agents, must conform with California Public Utilities Code Section 2889.5. All solicitations sent by LECs, CLCs or their agents to customers must be legible and printed in a minimum point size type of at least 10 points. A penalty or fine of up to $500 may apply for each violation of this Rule.

B. Unauthorized service termination and transfer ("Slamming")

A LEC or CLC will be held liable for both the unauthorized termination of service with an existing carrier and the subsequent unauthorized transfer to their own service. LECs and CLCs are responsible for the actions of their agents that solicit unauthorized service termination and transfers. A carrier who engages in such unauthorized activity shall restore the customer's service to the original carrier without charge to the customer. All billings during the unauthorized service period shall be refunded to the applicant or customer. A penalty or fine of up to $500 payable to the Commission may apply to each violation of this Rule. As prescribed under PU Code Section 2108, each day of a continuing violation shall constitute a separate and distinct offense. The LEC or CLC responsible for the unauthorized transfer will reimburse the original carrier for reestablishing service at the tariff rate of the original carrier.

RULE 14 - PRIVACY

CLCs are restricted from releasing nonpublic customer information in accordance with PU Code Sections 2891, 2891.1, and 2893. For each new customer, and on an annual basis for continuing customers, CLCs shall provide in writing a description of how the carrier handles the customer's private information and a disclosure of any ways that such information might be used or transferred that would not be obvious to the customer. CLCs are subject to the credit information and calling record privacy rules set forth in Appendix B of Decision Nos. 92860 and 93361, except as modified by Decision Nos. 83-06-066, 83-06-073, and 83-09-061.

D.3 California Statutes Applicable to Competitive Energy Service Retailers

The following subsections itemize some relevant portions of existing California statutes. This material is presented for information purposes only. No analysis has been performed to decide whether these provisions may be considered adequate to govern business practices in the electric services marketplace. Specific areas covered in these statutes include: prohibition of trusts and other forms of anti-competitive behavior; distinction between acceptable cost-based pricing and unfair discriminatory pricing; misleading advertising claims; equal treatment of customers with regard to credit and deposit policies; disclosure of credit terms; confidentiality of customer credit information; disclosure by businesses of their own financial status; fraud allegations against the customer; complaint resolution; and, consumer participation in rulemaking proceedings.

D.3.1 California Business and Professions Code Statutes for General Application

§ 16721. Prohibits a person from being disqualified from entering or pursuing a business, profession, vocation or employment based on sex, race, creed, color, or national or ethnic origin. This statutes guarantees the freedom to exercise and enjoy religion without discrimination.

§ 16725. Allows one to enter into an agreement or form associations and combinations to encourage and increase competition in any trade or industry.

§ 16726. Prohibits "trusts" as a matter of public policy. A trust is a combination of capital, skills or acts by two or more persons to create a restriction in trade or commerce, to limit production or increase the price of merchandise, to prevent competition, to fix and control the merchandise price.

§ 16727. Prohibits exclusive dealings with a person if the agreement or understanding will substantially lessen competition or create a monopoly in that trade.

§ 17001. Purpose of the Unfair Practices Act is to prevent monopolies and to encourage and foster competition.

§ 17040. Prohibits price discrimination by merchants between different sections, communities or cities with intent to destroy or prevent competition.

§ 17041. Allows exceptions for locality discrimination due to differences in grade, quality, or quantity or cost when based and justified by the cost to manufacture, sell or deliver, or the actual cost of transportation from the point of production or from the point of manufacture.

§ 17042. Allows customer selection and classification of a customer as a broker, jobber, wholesaler or retailer. Also allows a differential in price, based on the classification of the customer.

§ 17043. Prohibits a person from selling at below cost or from giving away a product for the purpose of destroying competition.

§ 17044. Prohibits a person engaged in business to sell any article or product as a "loss leader" (sold at less than cost).

§ 17045. Prohibits secret payments or allowances of rebates, refunds, commissions, or unearned discounts to certain purchasers, when the privileges are not extended to all purchasers. Also prohibited if the payment or allowance will destroy competition.

§ 17046. Prohibits threats, intimidation, or boycotts.

§ 17048. Prohibits collusion between manufacturers, wholesalers, distributors, jobbers, contractors, brokers, retailers, or other vendors.

§ 17508. Businesses cannot make misleading comparisons to a competitor. Businesses must provide facts supporting advertising claims, and regulators can get injunctive relief, or inform the public about misleading advertising, if the business engaging in allegedly false advertising fails to provide facts that substantiate the allegedly false claims.

D.3.2 Civil Code

Most of the following are industry-specific statutes, which are presented to offer examples of rules that might be adapted for the competitive electric industry.

§ 51 of the Civil Code is the State Civil Rights Act. One generic (non-industry-specific) rule the Act contains is to require that any criteria used to establish the need for a deposit shall be applied equally to all consumers.

§ 1770. Provides a list of deceptive practices in the sale of goods and services.

§ 1787.2. An applicant denied consumer credit shall be entitled to an explanatory statement.

§ 1785.15. Any written disclosure by a consumer credit reporting agency to a consumer shall include a toll-free number.

§ 1748.11 and 1748.22. These sections set forth the information that an issuer of credit cards must disclose in its applications including annual fees, percentage rate, etc.

§ 1747.10. Credit card customers are not liable for unauthorized use if the consumer gives adequate notice and fulfills various other requirements.

§ 1786.52. Consumer credit reporting agencies can be held liable for invasion of privacy.

§ 1786.14. Consumer credit reporting agencies must maintain procedures to prevent disclosure of consumer information, except for specified purposes.

§ 1950.5(f). Security deposits for rental agreements must be returned to the customer, minus legitimate deductions, within two weeks after service ends.

D.3.3 Insurance Code

§ 510. Provides for toll-free number for consumer affairs and insurer's obligation to inform customer of that number when it issues a policy.

§ 790.03 and 790.06. Where fraud is alleged by the provider, the consumer must be provided with specific notice of the allegations. The provider bears the burden of proof if the insurance commissioner has reason to believe that the insurance company's determination of fraud (or any act by the insurer) is unfair.

§ 12960-12962. The Insurance Commissioner shall make annual reports analyzing the condition of the insurance industry, tort actions, detailed financial information on the insurance industry, and recommendations to protect consumers from arbitrary insurance rates and practices. Similarly, where the marketplace information is inadequate, the Commission shall cause to compel provision of adequate information or the Commission will make such information available to the public independently.

§ 12921.1(e). The Insurance Commissioner shall make non-customer-specific information about complaints available to the public.

§ 1858.01. The Commissioner shall make a determination of probable cause on complaints filed with the Department of Insurance within 60 days, in the case of personal lines insurance.

§ 1858.02. The Insurance Commissioner may seek resolution of a complaint by "informal conciliation" at any time. The Commissioner may require the parties to meet and confer to resolve a complaint.

§ 790.05 and 790.06. Set forth procedures for dealing with unfair business practices of insurance companies, and consumer complaints made to the Department of Insurance. Consumers have the

right to appeal a complaint to the Commission for arbitration including the right to discovery, presenting evidence and cross-examining a provider representative at no cost to the consumer.

§ 1861.10. Provides for consumer participation and compensation in proceedings. Where policymakers conduct rulemaking or adjudicatory hearings on matters impacting consumers, consumers will be encouraged and enabled to effectively participate in such proceedings.

D.4 Rules for Competitive Energy Providers in Other States

D.4.1 Electric Industry Restructuring in Massachusetts

In April 1996 The Massachusetts Division of Energy Resources (DOER) issued in the form of a discussion draft a set of proposed rules to govern the restructured electric industry. The draft includes certain items relevant to Chapter 6 in this Report, in particular, corporate rules of conduct (which are virtually identical to the New Hampshire standards described in the next section) and registration requirements for retail electricity suppliers (see Section 6.1.3.1 of this Report). In May 1996 this discussion draft became a formal proposal of the Massachusetts Department of Public Utilities (see 220 CMR 11.00).

D.4.2 Direct Access Pilot in New Hampshire

In May 1996 the state of New Hampshire began a Direct Access Pilot Program, in which about thirty electricity retailers are competing for shares of the eligible three percent of the state's electricity load. An element of the regulatory framework for this pilot is a set of "Standards of Conduct" to govern the practices of the retailers. The standards were developed by a small group of stakeholders, including the Public Utility Policy Institute and the Granite State Taxpayers as well as some of the retailers, and were adopted by the state's PUC without modification.

The New Hampshire standards incorporate the following principles (from *Electric Power Alert*, June 19, 1996, pp 18-19).

1. A New Hampshire electric utility shall not give an affiliate preference over a non-affiliate in processing a request by a customer for service.

2. A New Hampshire electric utility shall supply services and apply tariffs to affiliates and non-affiliates in the same manner and shall uniformly enforce its tariff provisions.

3. A New Hampshire electric utility and/or its affiliates that are offering power to affiliates shall make the power available simultaneously to the market and all competitive suppliers on the same terms and conditions and at the same price.

4. A New Hampshire electric utility shall simultaneously make available to the market and all competitive suppliers any and all information it provides to affiliate competitive suppliers.

5. Employees of a New Hampshire utility who have responsibility for operation of the distribution system, such as receiving requests for power, purchasing power, or scheduling delivery, shall not be shared with an affiliate competitive supplier, and their offices shall be physically separated from the offices of the affiliate competitive supplier. Any shared facilities shall be fully and transparently allocated between the two entities. Separate books of accounts and records shall be maintained for each such affiliate.

6. A New Hampshire electric utility shall not condition the provision of any distribution services on the purchase of power from an affiliate.

7. A New Hampshire electric utility shall not allow its affiliate to utilize its name in any manner such that customers can reasonably imply from that use:
a. that the distribution services provided by the electric utility are of a superior quality when power is purchased from an affiliate; or
b. that the merchant services for power are being provided by the electric utility rather than by the affiliate; or
c. that the power purchased from a competing supplier may not be reliably delivered.

8. A New Hampshire electric utility shall establish and file with the Commission a dispute resolution procedure to address complaints alleging violations of these rules.

D.4.3 Codes of Conduct for Natural Gas Utilities in Other States

The following discussion summarizes some actual Codes of Conduct governing relations between local distribution companies (LDCs) and their retail marketing affiliates. The discussion roughly summarize the activities covered in (1) Standards of Conduct adopted by the New Jersey Board of Public Utilities, adopted in December 1995 following a consensus recommendation by a broad group of stakeholders; (2) New York "Interim Standards for Transactions between LDCs and Related Companies"; and (3) Maryland Public Service Commission, Order No. 72523 separating

Baltimore Gas and Electric (BGE, the LDC) from BNG, its wholly-owned marketing subsidiary, adopted April 1996.

FERC Order 497 contains Standards of Conduct for the wholesale gas market, which were adopted to address potential abuses in dealings between interstate gas pipelines and their merchant affiliates. The FERC Order 497 Standards are generally referenced by and provide a model for state standards of conduct for the unbundled retail gas market. The Standards of Conduct reviewed here also cover some of the firm-customer issues mentioned above.

In the retail gas market, the utilities are local distribution companies (LDCs) that provide gas transportation services for retailers, i.e., the merchants or marketers who procure gas from producers and sell it to consumers. In many instances the retailers are internal divisions of LDCs or their subsidiaries or affiliated companies.

At least one set of standards (New Jersey) was developed by consensus among LDCs, marketing affiliates, unaffiliated marketers, representatives of commercial and industrial customers (because retail unbundling is not yet available to residential customers), the Ratepayer Advocate and the Board's Gas Division Staff.

Standards are subject to review after one year, to reopen issues as necessary or to consider the need for codification of the standards as a legislative rule.

Activities and principles addressed by the standards (based on New Jersey and modified by New York and Maryland as indicated) are:

1- Comparable access to transportation service. Transportation tariffs, terms of access and all other practices of the LDC give no preference to affiliates over non-affiliated marketers.

2- Comparable access to non-public LDC information. Any information provided by the LDC to an affiliate shall be provided to all non-affiliated marketers at the same time.

3- Non-disclosure of private (customer) information. Information received by the LDC in providing transportation service shall not be disclosed to marketers, whether affiliated or not.

4- Physical separation and non-sharing of employees involved in LDC transportation operations.

5- Separate account books and records for LDC and marketing affiliate.

6- Any services provided by LDC to its affiliate (e.g., administrative and other support) must be charged at fully allocated cost.

Item 6 is expanded by Maryland to cover services provided by the LDC to its affiliate that could be marketed by the LDC and have market value to the affiliate. The imputed cost of such services must be their fair market value.

7- No tying of LDC transport discounts or interstate pipeline capacity release to any service in which the affiliate is involved.

8- Disclosure of all transport discounts. All LDC transport discounts must be filed, individually and in comprehensive quarterly reports, with the Board of Public Utilities (BPU). Such filings must disclose affiliate involvement in discounted transactions.

Item 8 is modified by Maryland to require disclosure of all discounts or special terms on "the general alert screen of [the LDC's] electronic bulletin board."

9- Surplus gas supplies or capacity sold by an LDC to its affiliate must be made available to all non-affiliated marketers.

10- Complaint procedure to be established and publicly filed by each LDC. Procedure must designate LDC person to receive complaints, who will acknowledge receipt of complaint in writing within 10 days, and will resolve complaint and report back to complainant within 30 days of receipt of complaint. LDC person must provide log of all new, pending and resolved complaints monthly to BPU Division of Ratepayer Advocate. BPU/DRA provides informal backup if LDC resolution is not satisfactory. Failing that, state Administrative Code provides formal backup.

11- No promotion of or marketing assistance to an affiliate by a LDC. (Added by New York.)

Item 11 is expanded by Maryland to include prohibition of joint calls and joint promotions. Marketing services such as affiliate promotional inserts in the LDC bill are permitted only if such services are offered to all competitors on identical terms.

12- Violations may result in affiliate's exclusion from doing business within the LDC's territory. (Added by New York.)

13- Transfer of assets must be valued based on asymmetric pricing: Greater of book or market value for transfers from LDC to affiliate; lesser of book or market value for opposite transfers. (Added by Maryland.)

D.5 Proposed Code of Conduct to Govern Retail Electric Service Transactions

This section contains some illustrative material that focuses mainly on consumer protection issues. Two subgroups of the DAWG (B, Market Rules, and D, Consumer Protection) discussed the need for and the general principles that should be embodied in such codes of conduct, but the level of specificity in the following material was not achieved in the discussions. We cannot say, therefore, what pros and cons or other alternatives the other parties might have offered had the working group addressed this level of detail.

D.5.1 ALTERNATIVE: The CPUC Must Require All Registered Energy Service Companies to Adopt a Minimum Code of Conduct

In the nascent energy services market, companies and customers will be unclear on their corresponding responsibilities and expectations. In order to facilitate a smoother transition to a robust competitive market, the CPUC should adopt a minimum code of conduct that will be provided to all energy service companies registering with the CPUC. This code would provide guidance for companies and their employees for all retail transactions.

This code shall be distributed to all employees of these energy service companies and provided to customers upon request. As a minimum code, this represents the "floor" of what would be expected, but can be surpassed by companies.

Such a code may be used as a standard upon which to judge company actions that are not covered by specific code language. It is neither likely nor desirable for regulators and lawmakers to devise rules and regulations for all possible forms of consumer problems. Thus, regulators will use the minimum code of conduct as a basis for determining the appropriateness of company conduct where no specific rule and regulation fits the conduct. Regulators may use the code as a basis for sanctioning a company.

D.5.2 Elements of a Minimum Code of Conduct

1. Customers deserve accurate and understandable information. The consumer has a right to price and service information that is presented in a cogent, understandable manner and which can be compared to similar service offered by other providers.

2. Electric service is a necessary service that all customers need. Treatment of customers must therefore reflect the importance of that service and the detrimental impact caused to customers when the service is not adequately reliable, safe and affordable (precise standards to be defined).

3. A customer has the right to written notice at least 30 days in advance of any change in terms of service or the manner in which rates are determined (forced outages excepted). Of course, if the customer's contract provides for variations in price due to market or other variables, no such notice is required.

4. When denied service, consumers should be notified of the reasons for such denial. This information will be provided promptly and in writing upon request.

5. Customers can be charged reasonable service deposits and will, in general, be entitled to refunds of deposits within a year after service is initiated assuming they have paid their bills as agreed. In some instances, however, deposits may be required for the duration of the contract. Criteria which establish the need for a deposit must be applied equally to all customers.

6. Customers will get timely and knowledgeable response from a company when a written complaint is filed with that company.

7. All customers will be given toll-free phone access by which complaints can be made or follow-up inquiries to written correspondence can be conducted.

8. No customer should be held responsible for any service used beyond the customer's control (precise terms to be defined, to ensure fair allocation of responsibility for payment).

Alternatively, some parties assert that customers should be responsible for all electricity used at their premises. Requiring UDCs or retailers to establish that billed usage was within the customer's control would be unworkable.

9. A residential customer threatened with disconnection has the right to at least 14 day advance written notice of an involuntary disconnection, except in cases of fraud. Current CPUC practice requires only 7 days notice for commercial customers, to prevent the service provider from being unduly saddled with the costs of bad debts and late payments.

10. Where fraud is alleged by the provider, the customer must be provided with specific notice of the allegations, and the provider bears the burden of proof.

11. In addition to legislative rights set forth in the state Constitution and legislative codes, the following provisions apply to customer-specific information held by energy service providers (see Chapter 7 for a full treatment of customer information issues).

11a. Explicit customer consent must be obtained prior to the release of personal information to any provider other than his/her own.

11b. The customer should be provided information, in writing, that informs the customer about the potential adverse privacy impacts of any new technologies deployed by providers, prior to signing up for a new service.

11c. Customers have the right to unlimited access to their own customer-specific information.

11d. Consumers should have a reasonable means to obtain, review, and when necessary correct and amend information about themselves as held by service providers.

11e. Customers should be permitted to choose among various degrees of privacy protection, with respect to both the outflow of information about themselves and the receipt of incoming intrusions.

12. Systematic abuses of customers or questionable practices of energy providers, even when being perpetrated by other companies, should be reported to authorities. Any market participant with evidence of such practices should contact the appropriate authorities and present that evidence posthaste. Unreported knowledge of such practices is tantamount to complicity.

13. Aggregation of communities should not discriminate against any group of consumers. Even where not intended, aggregation activity should not systematically exclude customer groups of different races, ethnicities, language, age and income levels. (This principle would need to be clarified to specify the parameters within which aggregators would be allowed to target specific customers and customer groups.)

Appendix E.

Laws and Precedents Regarding Customer Information

E.1 Legal Oversight of Information Dissemination

Table E.1 lists the laws and regulations applicable to electric utilities, other utility corporations, unregulated businesses, government, and individuals. The overriding intent of each law and regulation is also noted. In a few cases, where social benefits outweigh the costs of privacy intrusions, laws have been established to control the use of accessible personal information (e.g. PU Code 588 and Evidentiary Code 1060). In other cases, where there is minimal benefit to society, privacy is protected through the prohibition of access to personal information.

E.1.1 Public Utilities Codes Governing the Release of Electric Utility Customer-Specific Information

Sections 585 and 588 of Article 5 of the Public Utilities Code, have established precedents for the release and use of electrical corporation customer-specific records and information. Both sections were established by the Legislature to enable activities deemed to be beneficial to society. Section 585 allows for the release of customer-specific and other utility proprietary information to participants in rate setting proceedings. Section 588 permits release of specific personal customer information in the course of business performed by the district attorney's office. Both sections make it clear that information made available is to be used only for purposes established within each section, and protected by the receiving parties from other unauthorized use.

E.1.2 Other Electric Utility Practices

Customer-specific information is traditionally released by utilities under the following three conditions: (1) to designated parties when required by law or subpoena (e.g. P.U. Codes 585 and 588); (2) to a customer's agent upon written approval by the customer; and (3) without customer pre-approval, to suppliers under contract with, or providing services to utilities (e.g. collection agencies, researchers, and energy service providers).

DSM bidding pilot programs are an example of the latter. Implemented at Commission direction, personal information, including usage information, was released to winning bidders in advance of, or in some cases in lieu of customer notification and consent. For example, see D.95-02-042, under A.94-08-038, approving Contract Number C 9407-28028 between SDG&E and SESCO, Inc., with customer-specific information release procedures documented in Appendix C.

E.1.3 Other Utility Corporations

Under the Federal Communications Commission's (FCC) Bell Operating Companies (BOC) Safeguards Order, equal access to customer proprietary network information (CPNI) regarding customers with 20 lines or less was not deemed necessary. Under this order the affiliates of the BOCs had privileged access to CPNI. The FCC concluded equal access was unnecessary because industry competition had already been established.

The FCC also requires aggregated CPNI be made available to retailers on equal terms and conditions that apply to affiliates. Release of aggregate CPNI was allowed because it does not violate any individual's expectation of privacy. For a detailed discussion of these decisions, see the *Draft IAST Report: Access to Strategic Customer Information to Facilitate Meaningful Consumer Choice for Energy Services*, prepared by the Information Access Study Team, Kristov (IAST Project Lead), California Energy Commission, February 1996.

E.2 Unregulated Oversight of Information Dissemination

E.2.1 U.S. Department of Commerce Findings

In October, 1995, the National Telecommunications and Information Administration (NTIA), under the U.S. Department of Commerce, published a report recommending guidelines for accessing telecommunications-related personal information. *Privacy and the NII: Safeguarding Telecommunications-Related Personal Information*, U.S. Department of Commerce, October 1995 (NTIA Report).

In those recommendations, the NTIA suggested that "sensitive" personal information not be used for ancillary purposes "without first obtaining explicit authorization from the relevant customer." It went on to state that the use of "non-sensitive" personal information should be allowed for unrelated purposes "unless the customer affected, having been notified of the company's plans, takes some action stopping such use."

E.2.2 Trade Organization Oversight

Trade organizations, such as the Direct Marketing Association (DMA), have established protocols for accessing personal information for marketing purposes. Specifically, DMA suggests consumers "periodically should be informed of the potential for the rental, sale or exchange of data," and offered "an opportunity to have (their) name deleted or suppressed upon request." From Article 5 in *Fair Information Practices Manual: A Direct Marketer's Guide to Effective Self -Regulatory Action in the Use of Information*, Direct Marketing Association, Inc., October 1994. Notification can take the form of explaining how information is going to be used, with an address to which the consumer can write with their request, or a phone number to call.

Appendix G.

Existing Standards for Metering Device Components

The metering standards define all electrical and mechanical parameters of electric meters and metering devices. For example, ANSI C12.10 includes specifications for the physical construction, wiring, environmental requirements, mounting, voltage, frequency, test currents, form designations, register and rotor construction, calibration adjustments, nameplates, sealing, and terminal connections for electromechanical watt-hour meters.

Standards exist for the following meters and metering devices and should continue in use:

Code for electricity metering
Mechanical demand registers
Thermal demand meters
Marking and arrangement of terminals for phase-shifting devices
Watt-hour meter sockets
Test blocks and cabinets for installation of self-contained A-base watt-hour meters
Test switches for transformer-rated meters
Electromechanical watt-hour meters
Instrument transformers - current and potential transformers
Electronic time-of -use registers for electricity meters
Magnetic tape pulse recorders for electricity meters
Solid-state demand registers for electromechanical watt-hour meters
Solid-state electricity meters
Cartridge-type solid-state pulse recorders for electricity metering
Protocol specification for ANSI type 2 optical port

Appendix H.

ANSI Standards for Metering

ANSI C12.1 - American National Standard Code For Electricity Metering

ANSI C12.4 - American National Standard For Mechanical Demand Registers

ANSI C12.5 - American National Standard For Thermal Demand Meters

ANSI C12.6 - American National Standard For Marking And Arrangement Of Terminals For Phase-Shifting Devices Used In Metering

ANSI C12.7 - American National Standard For Watt-hour Meter Sockets

ANSI C12.8 - American National Standard For Test Blocks And Cabinets For Installation Of Self-Contained A-Base Watt-hour Meters

ANSI C12.9 - American National Standard For Test Switches For Transformer-Rated Meters

ANSI C12.10 - American National Standard For Electromechanical Watt-hour Meters

ANSI C12.11 - American National Standard For Instrument Transformers For Revenue Metering, 10 kV BIL Through 350 kV BIL

ANSI C12.13 - American National Standard For Electronic Time-Of -Use Registers For Electricity Meters

ANSI C12.14 - American National Standard For Magnetic Tape Pulse Recorders For Electricity Meters

ANSI C12.15 - American National Standard For Solid-State Demand Registers For Electromechanical Watt-hour Meters

ANSI C12.16 - American National Standard For Solid-State Electricity Meters

ANSI C12.17 - American National Standard For Cartridge-Type Solid-State Pulse Recorders For Electricity Metering

ANSI C12.18 - American National Standard For Protocol Specification For ANSI Type 2 Optical Port

Appendix J.

Example Charter for

the Restructured Electric Service Education Trust

The Restructured Electric Service Education Trust (RESET) Committee will develop a charter detailing the purpose, structure, duties and conduct of RESET. An example of such a charter is provided in the remainder of this appendix.

EXAMPLE

CHARTER OF THE

RESTRUCTURED ELECTRIC SERVICE EDUCATION TRUST

I. NAME

The name of the committee shall be the Electric Consumer Education Trust Committee (referred to hereafter as "RESET" Committee).

II. PURPOSE

The RESET Committee's general purpose is Consumer Education mandated by _____ (Section xxxx of the Public Utilities Code, or other authority), for providing education for consumers concerning the restructuring of the provision of electricity services in California.

III. MEMBERSHIP

A. Members. The RESET Committee shall be comprised of twelve (12) members as follows:

1. Members shall include:

   (a) Service Provider members -
   (b) Consumer Members -

2. Member(s) -- Shall be three from the California Public Utilities Commission (CPUC), one each from San Diego Gas & Electric Co., Pacific Gas & Electric Co. and Southern California Edison, three from established consumer groups and three from electric service retailers in competition with established utilities.

B. Selection of Members. Initial selection shall be determined by the Commission. Thereafter, potential members of the RESET Committee shall be nominated by the organizations or constituencies they are to represent. The members of the RESET Committee shall be recommended for approval by the Commission's Executive Director, according to procedures preferred by the Commission.

C. Qualifications of Members. The qualifications of members shall be established by the RESET Committee in conjunction with the CPUC. In general, members shall have professional or technical expertise sufficient to enable them to be conversant with the responsibilities of RESET. Consumer members should be able to demonstrate organizational or other ties to the constituency they are representing, and in addition, they should not be employed by or represent the interests of any vendors or distributors who are providing or who may in the future provide equipment or services related to consumption of electricity, consistent with the Disclosure and Conflict of Interest Policy attached to this charter. (To be developed and attached.)

D. Term of Appointments. The terms of the members of RESET Committee shall be staggered, with one-third of the membership appointed each year. Initial appointments shall be for terms of one, two or three years; thereafter members will be appointed for three-year terms. A member may be re-appointed, but no member shall serve for more than two consecutive full terms.

E. Removal from Membership.

1. Membership may be terminated through resignation.
2. Members who fail to attend three consecutive meetings without just cause or proxy may be subject to removal from committee.
3. Any member of RESET Committee, on the recommendation of two-thirds of the RESET Committee, may be removed by the Commission's Executive Director for cause shown, in procedures preferred by the Commission.

F. Vacancies. Vacancies on the RESET Committee shall be filled from nominations submitted by the organization or constituency whose vacancy is being filled. The membership of persons filling a vacancy shall be selected and approved by the Commission's Executive Director using procedures preferred by the Commission. Vacancies for expired terms will be filled by full-term appointments; vacancies for unexpired terms will be filled for the remainder of the term.

G. Expenses. Consistent with Commission Resolution __?__, consumer members of RESET Committee shall be entitled to appropriate reimbursement of expenses they incur in connection with their services on the RESET Committee. Expenses will be reimbursed in accordance with the Commission's travel expense claim rules applicable to its own employees. Utility members and other service providers are not eligible for expense reimbursement.

IV. DUTIES AND RESPONSIBILITIES

The RESET Committee shall have the following duties and responsibilities:

A. (To be specified.)

B. Provide representation on any specially created Task Force.

C. Perform other functions and duties as may be directed by the CPUC.

V. MEETINGS

A. Regular Meetings. The RESET Committee shall hold such meetings as it shall decide are necessary or appropriate in order to carry out its functions. The succeeding meeting, place, time and location shall be scheduled at the preceding meeting. All meetings shall be open to the public, shall be noticed, shall be conducted pursuant to Robert's Rules of Order, 199x Edition, and shall be otherwise held in accordance with the provisions of Government Code Sections 11120 ff.

B. Special Meetings of the Committee. Special meetings of the RESET Committee may be called by the Chair or by a quorum. All RESET Committee members are to be notified at least three days prior to the special meeting.

Such notices shall:

1. Set forth the date, time and location of such meeting.
2. State the business to be conducted at such meeting.

C. Public Participation. All meetings will be open to the public. Each meeting shall have a specific portion of the meeting agenda devoted to the presentation of questions, comments, and suggestions from any non-member of RESET present on accordance with Government Code Sections 11120 ff. Members from the public and observers shall not be permitted to take part in any meeting unless recognized by the Chair. The RESET may limit time for public participation, depending on the number of participants and the content of the overall agenda.

D. Quorum; Eight authorized members or their designated representatives shall be necessary to constitute a quorum for performing RESET Committee functions. No action shall be taken unless a quorum is present. A majority of the members present at a meeting, whether or not a quorum is present. A majority of the members present at a meeting, whether or not a quorum is present, may adjourn the meeting to another time or place. Any adjourned meeting shall be subject to the same notice requirements as a regular meeting.

E. Proxies. A member may be represented at any meeting by oral or written authorization by that member to the chair naming a designated individual to represent the member at a specified, noticed meeting. Any proxy may be revoked at any time before the meeting begins by oral or written notice to the chair by the member who gave the proxy.

F. Motions. Any member may submit motions from the floor for RESET vote.

G. Agenda. Each notice of meeting shall be accompanied by an agenda setting forth the matters that are expected to be presented at the meeting. Each agenda shall include allotted time for public input. Except in an emergency and with the approval of a majority of the members present, RESET Committee shall not consider at any meeting an item not on the agenda.

H. Participation. Members of the public and observers shall not be permitted to take part in any meeting unless recognized by the chair.

VI. OFFICERS

A. Two Officers. The RESET Committee shall have a Chairperson and a Vice Chairperson, both of whom shall be elected by a majority of the members to serve for one year from date of election and may be re-elected.

B. Duties. The Chairperson shall be the executive officer of the RESET Committee and subject to the control of the RESET Committee and this Charter, have the general supervision and direction of the affairs of the RESET Committee. The Chairperson shall preside at all general and special meetings of RESET Committee, set the agenda for place and time of meetings, appoint Task Forces as needed, and submit proposals and recommendations to the CPUC. In the event of a vacancy of the office of Chairperson, the vacancy shall be filled by a majority vote of the members of RESET Committee. The Chairperson so appointed shall serve out the term of the vacancy that has been filled.

The Vice Chairperson shall perform the duties of the Chairperson when the Chairperson is unavailable.

VII. AMENDMENTS

The RESET Committee may recommend that the Charter be amended at a regular meeting by a vote of a majority of its voting members. Any proposed amendment must have either been proposed at a previous meeting or have been received by RESET Committee members at least ten days in advance. Any revisions shall not become effective until approved by the CPUC.

VIII. INDEMNIFICATION

Members of the Committee, who are not members of the Commission staff, are uncompensated servants of the Commission and the State of California within the meaning of Section 810.2 of the Government Code. The State will accordingly indemnify them as it indemnifies its compensated employees, and will provide them representation by the California Attorney General, for their acts done within the course and scope of the services they perform for the Committee, as provided in Government Code Sections 825 et seq. and Sections 995 et. seq.

IN WITNESS WHEREOF, we the undersigned members of the Electric Consumer Education Trust Committee do hereby constitute, establish, and adopt this as the charter for said committee effective as of the day, month, and year first written.