Staff Testimony:
Customer Responses and Welfare Changes
To A Restructured Electricity Industry

Prepared for the August 14, 1996 ***ER 96*** Committee Hearing

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INTRODUCTION

This testimony discusses issues related to order numbers I.A.2 and I.A.4 in the ***ER 96*** **Committee's** February 15, 1996, Order. The Committee issue I.A.2 asks,

> **What are the likely customer responses to prices and rates, in shifting consumption patterns and reducing bill impacts?**

Issue I.A.4 asks,

> **What is the likely increase in consumer value from the establishment of the Independent System Operator, the Power Exchange, and other features of the California Public Utilities Commission's (CPUC) proposal?**

Such questions are difficult to answer because: (1) the final industry structure is yet unknown; (2) the prices for the unbundled components of generation, transmission and distribution have not been determined; (3) the rate designs for recovery of monopoly services are undefined; and (4) there are few observable consumer responses with which to predict future behavior.

As an illustration of the assessments needed to answer these questions for the residential sector Staff examines customer responses by assuming two possible structures. First, Staff assumes that a restructured electricity industry will employ a more efficient rate design for monopoly services. As such, Staff examines the impacts on customers of a two-part tariff as a mechanism by which fixed costs can be efficiently recovered. The analytical development of a two-part tariff provides Staff the opportunity to examine the change in consumer value stemming from the establishment of the Power Exchange, Independent System Operator (ISO) and the Utility Distribution Company (UDC). Second, Staff examines the issues surrounding the CPUC's proposed customer choice between opting to be an average-rate customer, a virtual direct access customer or an aggregated customer. Specifically, Staff examines how such rates may cause adverse selection on the part of consumers and the "triple benefits" [1] of restructuring foreseen by the CPUC for the average residential customer reduced in the absence of supplemental efforts, such as efficient rate design to ensure these benefits are achieved.

For the commercial and industrial sector Staff examines the current rate structure and prices faced by customers on various rate schedules. We then describe the characterize the choices different classes of commercial and industrial customers will have in a restructured industry relative to their current situation.

[1] The triple benefits include: cost reduction for any consumer who is able to shift load, deferring the production of new generation, and more productive use of existing plant and equipment.

SUMMARY

Residential Sector

Staff examined the residential response to electricity industry restructuring within a framework of efficiency. We illustrated that a two-part tariff is an economically efficiency rate design with which to recover the fixed costs of distribution, public service programs and the competitive transition charge. But more importantly, we found that the design of a two-part tariff is critical to increasing welfare while at the same time maintaining equity. And that there are a variety of ways to implement a two-part, this testimony analyzes two different scenarios.

Staff also examined the residential customer responses to the choice of virtual direct access. We found that customers with relatively flat loads are the most likely candidates to choose virtual direct access; but, they will not necessarily shift load. Moreover, to the extent these flat load customers choose virtual direct access it will shift costs to the average rate customers. That is contrary to CPUC's assertion that average rate customer will not see a change in their bills. The average rate customers cannot be guaranteed an "exact replica" of their current bills without the CPUC dictating to the utilities that this be done, irrespective of the details of various specific restructuring decisions. Indeed because switching to virtual direct access is voluntary, we should expect adverse selection to lead to a disproportionate selection of virtual direct access by flat load customers who will thereby shift costs to high peak load, average rate customers. Ironically, it is these relatively high peak using customers who in many cases are the very ones capable of shifting their load to realize the "triple benefits" touted by the CPUC. But, since they risk a loss, becoming virtual direct access customers and not shifting enough of their load to reduce their bills, such customers are least likely to opt for virtual direct access unless extensive informational programs are developed to ensure that customers understand the consequences of their choices.

Commercial and Industrial Sector

In examining the response of commercial and industrial (C/I) customers it was necessity to frame our answer in qualitative terms. Information about customer responses to prices (viz., elasticities) are not available or cannot be calculated for markets that do not yet exist. Moreover, it is apparent that customers will react to more than just price signals. Non-price factors are likely to be as important in customers' decisions about consumption and choice of supplier as price. The unbundling and cost of services will also have an effect on C/I customer choices. Marketing and pricing strategies will be also be important.

Although California relatively high rates have been a driving factor in the restructuring movement, these rates by themselves may not motivate many C/I customers to modify their use of electricity or to switch suppliers. Rates for many of the larger C/I customers are already low, thus somewhat reducing the incentive to change consumption patterns in order to reduce bills. Some of the larger C/I customers also self-generate or have negotiated special anti-bypass rates, which reduces the impact on bills of current rate structure. If these rates have hidden subsidies embedded in them these customers may find themselves facing higher bills after restructuring. For many of the small and medium C/I customers, rates are high and the incentive is great for them to modify their usage or seek new, lower cost suppliers.

TWO-PART TARIFF

A fundamental concept developed in the ***1994 Electricity Report*** (***ER 94***) was that electricity services should be priced efficiently. Economic theory suggests that in order to increase efficiency, prices paid by consumers should more closely reflect marginal costs. This fundamental concept is now being echoed in the Direct Access and Ratesetting Working Groups formed to implement the restructuring policy decisions of the CPUC.[2] Efficient pricing requires that prices paid by consumers more closely reflect the marginal costs of the services provided. A two-part tariff is one mechanism by which efficient pricing can be implemented. Such a rate structure more closely reflects the fixed and variable costs components of unbundled electric services. In this testimony Staff examine the implications of a two-part tariff. Specifically, we analyze the competing issues of equity and efficiency surrounding implementation of a two-part tariff.

This section of testimony is organized in the following manner. First, the economic basis for a two-part tariff is reviewed. Second, the current residential rate is unbundled and revenue contribution identified. Third, residential electrical usage and expenditures are examined.

Economic Basis For A Two-Part Tariff

Generation of electricity and the transmission/distribution of it to end-users are two distinct services. Distribution costs are independent of generation and should not be recouped as a scalar to the Power Exchange price (x plus cents per kWh). Most of the costs associated with the distribution system are incurred at the time of construction. These costs and the ongoing costs of maintenance do not vary with usage. Given the fixed nature of distribution costs a two-part tariff would be a more efficient rate design for an integrated utility. Distribution costs would be recovered in the fixed component of the tariff with energy costs being recovered in the variable component. Such a rate design would increase economic efficiency for two reasons. First, the variable (kWh) component of the rate would more closely reflect the marginal cost of generation. Second, the fixed portion of the tariff would reflect the largely fixed costs of the distribution system.

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[2] CPUC Decision D. 95-12-063, dated December 20, 1995. This decision pertains to the Investigation and Rulemaking opened in April, 1994, and known as the "Blue Book." See CPUC "Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation," R.94-04-031, and "Order Instituting Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation," I.94-04-032. Also see CPUC Decision D. 96-03-022, known as the "CPUC Roadmap", dated March 13, 1996.

In a restructured electricity industry these services will not only be distinct, they will be provided by different entities. Thus, the economic efficiencies of a two-part tariff for an integrated utility become essential for a restructured industry in which separate companies provide component services that were previously bundled together. Generation of electricity will occur in a competitive market, with many companies serving customers directly, through bilateral contracts, or indirectly, by selling electricity through the Power Exchange. The transmission and distribution of the electricity to the end-user will be provided by two entities--the Independent System Operator (ISO) and Utility Distribution Companies (UDCs). Pricing of the transmission services of the ISO will be set by the Federal Energy Regulatory Commission (FERC) and is beyond the scope of this testimony. Pricing of the distribution services of the UDCs will be under the auspices of the CPUC and the rates designed such that economic efficiency is increased.

The value of constructing an efficient rate design is that it provides the consumer with correct cost signals. Prices are a compact means for transmitting information about the cost consequences of consumer decisions. If prices are set right, and societal marginal costs are accurately aligned with marginal rates, then the cost consequences of consumer decisions will be the same as the cost consequences for society as a whole. Such prices are thus necessary to assure that consumers are provided correct information about their energy choices. If the UDC's rates includes a scalar to marginal generation costs, in order to recover fixed distribution costs, as is now done and as it is proposed in the CPUC's restructured decision, consumers will continue to be provided with the wrong signal as to the relative costs of their energy choices--gas versus electrical fuel choice, or electrical usage versus investment in energy efficiency measures. An artificially high variable energy cost induces customers to over invest in energy efficiency that is not cost effective to society, causing an inefficient misallocation of resources.

Creating a fixed component in a tariff also increases economic efficiency because it constitutes payment for the right to access. Access rights have value independent of usage. For example, a vacation home that has electric service is more valuable that one that does not. Moreover, the costs of supplying such a vacation home with access to electric service needs to be recovered even if no electricity is consumed. Without a two-part tariff the cost of electricity access for such a vacation home must be subsidized by all other electric consumers. Such hidden subsidies are inefficient because their incorporation into price provide the consumer with the wrong signal as to the true cost of the service.

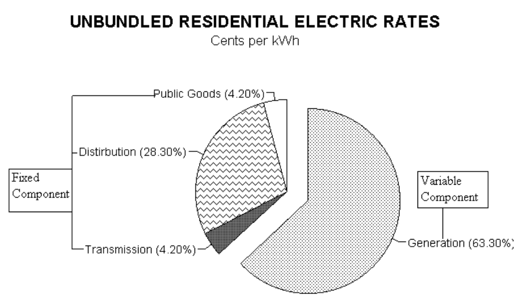
Unbundling The Residential Average Rate

Identifying the costs for the unbundled components of generation, transmission and distribution can be done best through new utility cost studies. However, while such cost studies have been directed by the CPUC, they do not yet exist.[3] As an alternative, Staff has used a

[3] Assigned Commissioner Ruling of June 21, 1996, requires that utilities file conceptual rate design proposals on July 15, 1996. An element of these filings will be cost of service study proposals.

proportional breakdown of costs for generation, transmission, distribution and public service. Generation costs vary with usage. Thus, these costs should be part of the variable component of a two-part tariff. The greatest portion of transmission, distribution and public service costs do not vary with usage. Thus, these costs should be part of the fixed component of a two-part tariff. **Figure 1** displays these shares as a percentage of the current rate, in cents per kWh, that the residential customer pays.[4] Staff is aware that deriving component costs from proportional shares of revenue collected by utilities is inexact; however, it is the only data available to us at this time. The reader should also be aware that these shares will vary by utilities and that different estimates of these shares exist. Even so, Staff believes that the analysis resulting from the use of this data helps to illustrate the impacts of switching to a two-part tariff.

Figure 1



Examination of Residential Usage and Expenditures

Switching to a two-part tariff will impact consumers differently depending on usage. In order to determine the effects on consumers' bills Staff created a residential data set. The data set is a subset of responses from a residential customer survey. The subset includes over 10,000 households for which there was an entire year's worth of data. Staff believes that this subset is robust and the analysis representative of California's residential sector.

Households in the data set were categorized into different usage groups based on their annual level of consumption. The data was first stratified into climate zones, then further stratified by level of consumption into six usage (kWh) groups, and finally, each usage group was di-

[4] Utility presentation at the CPUC Ratesetting Working Group Meeting of April 15, 1996.

vided into seasonally important sub-groups by examining consumption in summer and winter months. This stratification was necessarily in order to begin to capture the differences in distribution costs due to variation in regional climatic conditions and end-use saturations. Distribution systems are built to handle the specific peak loads of distinct geographical regions. Therefore, a portion of fixed costs differ based on the non-coincident peak demand the regional system is built to handle. Distribution systems built to serve large residential homes, saturated with air conditioning loads will incur more costs at the primary and secondary sub-stations and with the capacity of the distribution wires than will regional systems built to serve small homes having no air conditioning loads.

Table 1 displays the average use, bills and rates for the six aggregated usage groups. Although the analysis was done at the climate zone level Staff, for brevity, reports the results at the aggregated usage level. The impact on bills across usage groups is more important to the analysis than is the impact on bills across climate zones.

Table 1
RESIDENTIAL USAGE PATTERN

Consumption Groups	Average Annual Use (kWh)	Average Annual Bill	Average Annual Rate	Monthly Bill
Lowest 10%	1,680	$156	$0.09	$13
10% - 25%	3,120	$286	$0.09	$24
25 - 50%	4,737	$460	$0.10	$38
50% - 75%	6,955	$726	$0.10	$60
75% - 90%	9,731	$1,059	$0.11	$88
Highest 10%	15,624	$1,749	$0.11	$146
Total/Average	**6,579**	**$689**	**$0.10**	**$57**

Combining the information from **Figure 1** with that of **Table 1** the average residential customer's bill was unbundled into the separate service costs of generation, transmission, distribution and public service. **Table 2** displays this information based on current rate designs. This information is provided so that cost allocations associated with a two-part tariff can be compared to those in current rates.

Table 2
AVERAGE CUSTOMER'S UNBUNDLED BILL

ANNUAL VALUES					
Consumption Groups	**Generation**	**Transmission**	**Distribution**	**Public Service**	**Total**
Lowest 10%	$98	$7	$44	$7	$156
10% - 25%	$181	$12	$81	$12	$286
25% - 50%	$291	$19	$130	$19	$460
50% - 75%	$459	$30	$205	$30	$726
75% - 90%	$670	$44	$300	$44	$1,059
Highest 10%	$1,107	$73	$495	$73	$1,749
Average	**$436**	**$29**	**$195**	**$29**	**$689**
MONTHLY VALUES					
Consumption Groups	**Generation**	**Transmission**	**Distribution**	**Public Service**	**Total**
Lowest 10% Usage	$8	$1	$4	$1	$13
10% - 25% Usage	$15	$1	$7	$1	$24
25% - 50% Usage	$24	$2	$11	$2	$38
50% - 75% Usage	$38	$3	$17	$3	$60
75% - 90% Usage	$56	$4	$25	$4	$88
Highest 10% Usage	$92	$6	$41	$6	$146
Average	**$36**	**$2**	**$16**	**$2**	**$57**

Table 3 displays the total revenue collected from customers in the data set. Each user group's expenditures represent a contribution to the unbundled revenue requirement of their utility. The expenditures were determined by multiplying total consumption by the average rate to the unbundled rate proportions displayed in **Figure 1**. This data is displayed as a point of reference for development of the two-part tariff.[5]

Table 3
CONTRIBUTION TO REVENUE REQUIREMENT

Consumption Groups	Total Annual Use	Genr.	Trans.	Distr.	Public Service	Total
Lowest 10%	2,751,578	$161,320	$10,704	$72,123	$10,704	$254,851
10% - 25%	7,658,882	$445,055	$29,530	$198,974	$29,530	$703,089
25% - 50%	19,355,971	$1,190,950	$79,020	$532,447	$79,020	$1,881,437
50% -75%	28,445,606	$1,879,249	$124,690	$840,170	$124,690	$2,968,799
75% - 90%	23,870,784	$1,644,611	$109,121	$735,269	$109,121	$2,598,122
Highest 10%	25,514,340	$1,807,512	$119,930	$808,098	$119,930	$2,855,470
Totals	**107,597,161**	**$7,128,697**	**$472,995**	**$3,187,081**	**$472,995**	**$11,261,768**

TWO-PART TARIFF STRUCTURES

In this section the fixed and variable charges of an illustrative two-part tariff are derived, and new bills calculated for the average customer in six different consumption categories. Here the reader must keep in mind the assumptions that are used in developing this two-tariff, referred to as **Example A**. In developing this illustrative two-part tariff we assume no change in consumption resulting from the its implementation. As such, there is no overall welfare gain associated with its implementation. However, such an analysis allows us to identify the differences in allocation of fixed costs within current rates. In **Example B** we use the cost differences developed in **Example A** to look at the welfare gains when we assume consumers will react to the lower marginal price in the two-part tariff. It is in this example that the welfare and efficiency gains of the two-part are identified.

Developing an Illustrative Two-Part Tariff, Example A

[5] Exact duplication of Staff's results with this data is not possible since our analysis was done at the climate zone level. However, verification of the magnitude of the changes in consumers' bills is possible if the reader chooses to verify our work.

This sub-section develops the illustrative fixed charges of Staff's proposed two-part tariff. The section begins with the derivation of fixed distribution charges. Staff then develops the fixed charges for the public service component and competitive transition charge (CTC). Pricing of the transmission services of the ISO will be set by the Federal Energy Regulatory Commission (FERC) and is beyond the scope of this testimony. As such, for purposes of this testimony transmission costs will continue to be recovered as a scalar to generation costs.

Derivation of Fixed Charges

In order to increase economic efficiency the fixed distribution costs of the UDC should be recovered in a fixed charge. However, the fixed charge should reflect differences in costs incurred when serving distinct usage groups. As pointed out earlier, distribution systems are built to handle the specific peak loads of distinct geographical regions. Therefore, a portion of their fixed costs vary based on the non-coincident peak demand the regional system is built to handle. For purposes of this analysis Staff has tried to capture the regional differences in fixed distribution costs by assuming that half of the distribution costs are dependent upon the size of peak load the system was built to handle.[6] For actual implementation of a two-part tariff utilities could do a much more precise formulation of these regional fixed costs. Utilities have hundreds of local distribution systems. Each is built to meet the non-coincident peak load of that area, and the utilities have cost data on which to precisely derive the fixed portion of a two-part tariff by region.

The fixed distribution charge of the two-part tariff was derived by allocating the current contribution made by residential customers in the data set to each of the usage groups. Under the current rate structure the residential customers in this survey contributed $3,187,081 to their utilities' fixed distribution costs. For reasons stated previously, Staff allocated 50 per-cent of the revenue collected to the individual consumption groups weighted by usage. The weights were derived by summing July and December loads of each usage group and dividing it by the sum of July and December usage from the entire data set. These weights are our best allocation of regional distribution costs among the usage groups. Staff would expect a more precise allocation of costs based on actual data if this rate design were implemented. The remaining 50 percent of the distribution revenue was allocated equally among the usage groups. The fixed distribution charges were then derived by dividing the allocated fixed costs of the usage groups by the number of customers in each group.

Public Service and Competitive Transition Charges

The economic rational for a fixed distribution charge can also be applied to the public service component and competitive transition charge. The annual fixed public service charge was derived in the same manner as that of the fixed distribution charge. The public service charge covers expenditures by utilities on research and development, load management programs, energy efficiency programs and low income programs. Under the current rate structure

[6] Staff used 0.5 as the share of distribution costs dependent on the non-coincident peak of the region so as to minimize our error. At this time Staff does not know how much distribution costs vary by region.

residential customers in this survey contributed $472,995 towards recovery of these expenditures. All of these expenditure are fixed once programs are implemented. And since a large portion of these expenditures benefit high users (e.g., research and development, load research studies) Staff weighted these costs in the same manner it weighted the distribution costs.

The Competitive Transition Charge (CTC) was derived in a multi-step process. First, total revenue from economic assets of $3,120,000 was derived by assuming an average power exchange price of 2.9 cents per kWh. This revenue was then subtracted from the current generation revenue of $7,129,000. The difference, $4,009,000, is used by Staff as the CTC for the purpose of this analysis. Staff is not suggesting that this methodology be used in deriving the actual CTC. We are, however, advocating that economic efficiency would be increased if the CTC was recovered as part of a fixed charge in a two-part tariff rather than a scalar to the Power Exchange's spot price.

For our analysis 100 percent of the CTC charge is allocated to each of the usage groups based on the weights developed for the fixed distribution charge. Our rational for weighting the CTC is based on the assumption that a larger portion of the CTC should be paid by users that contributed most to the need for new capacity during the regulated era--high peak users. The annual fixed CTC charge per customer was then derived by dividing the weighted CTC total by the number of customers in each usage group.

The fixed and variable charges of the two-part tariff are shown in **Table 4**. The reader is cautioned that these charges are for illustrative purposes only. Charges developed using actual costs would certainly differ. However, Staff believes the data are illustrative of the magnitude of the charges associated with the implementation of a two-part tariff. The reader should also be aware that the total bills in **Table 4** were calculated on the assumption that the consumer does not respond to the lower marginal price of 2.9 cents per kWh. Staff analyzes the implication of relaxing this assumption in a later section.

Table 4
TWO-PART TARIFF FOR AN AVERAGE CUSTOMER

ANNUAL VALUES							
	Fixed Charges				Variable Charges		
Consumption Groups	**Public Service**	**CTC**	**Distri-bution**	**Total Fixed**	**Power Exchange**	**Trans-mission**	**Total Bill**
Lowest 10%	$18	$62	$122	**$203**	$49	$7	$258
10% - 25%	$21	$116	$144	**$281**	$90	$12	$383
25% - 50%	$25	$176	$167	**$368**	$137	$19	$525
50% - 75%	$30	$259	$200	**$489**	$202	$30	$721
75% - 90%	$36	$364	$242	**$641**	$282	$44	$968
Highest 10%	$49	$583	$329	**$961**	$453	$73	$1,488
MONTHLY VALUES							
	Fixed Charges				Variable Charges		
Consumption Groups	**Public Service**	**CTC**	**Distri-bution**	**Total Fixed**	**Power Exchange**	**Trans-mission**	**Total Bill**
Lowest 10%	$2	$5	$10	**$23**	$4	$1	$28
10% - 25%	$2	$10	$12	**$31**	$8	$1	$39
25% - 50%	$2	$15	$14	**$41**	$11	$2	$54
50% - 75%	$2	$22	$17	**$53**	$17	$3	$73
75% - 90%	$3	$30	$20	**$80**	$24	$4	$107
Highest 10%	$4	$49	$27	**$80**	$38	$6	$124

Differences in Contribution To Distribution Costs

Comparing the distribution charges in **Table 2** with those in **Table 4** reveals differences customer contribution to fixed distribution costs within current rates. It is important to identify these differences because they may provide consumers with the wrong signal to as to the true costs of their consumption decisions. **Table 5** displays the differences in recovery of fixed costs between the current rate design with that of a two-part tariff.

Table 5

CHANGES IN CONTRIBUTION TO FIXED COSTS

ANNUAL VALUES						
	Current Rate Design		Two-Part Tariff		Differences	
Consumption Groups	Public Service	Distri-bution	Public Service	Distri-bution	Public Service	Distri-bution
Lowest 10%	$7	$44	$18	$122	($12)	($78)
10% - 25%	$12	$81	$21	$144	($9)	($63)
25% --50%	$19	$130	$25	$167	($6)	($37)
50% - 75%	$30	$205	$30	$200	$1	$5
75% - 90%	$44	$300	$36	$242	$9	$58
Highest 10%	$73	$495	$49	$329	$25	$166
MONTHLY VALUES						
	Current Rate Design		Two-Part Tariff		Differences	
Consumption Groups	Public Service	Distri-bution	Public Service	Distri-bution	Public Service	Distri-bution
Lowest 10%	$1	$4	$2	$10	($1)	($7)
10% - 25%	$1	$7	$2	$12	($1)	($5)
25% --50%	$2	$11	$2	$14	($0)	($3)
50% - 75%	$3	$17	$2	$17	$0	$0
75% - 90%	$4	$25	$3	$20	$1	$5
Highest 10%	$6	$41	$4	$27	$2	$14

The difference between what the average consumer in each usage group contributed to distribution costs and what one should have contributed represents an incorrect price, assuming these costs are independent of usage and ignoring any geographic cost differential (e.g., urban versus rural, high density versus low density, low weather disruption versus high weather disruption, etc.).

Implications of the Illustrative Two-Part Tariff and Alternative Designs

This section analyzes the two-part tariff developed in **Example A**. Staff acknowledges that the data used is inexact. However, the relative magnitude of the charges and changes in customer bills are representative of the implications of switching to a two-part tariff. This section begins by examining the welfare changes resulting from the illustrative two-part tariff in **Example A**. Staff then develops an alternative structure for the two-part tariff **, Example B**. This alternative structure would increase overall welfare and efficiency.

Welfare and Efficiency Changes

The change in consumer welfare resulting from implementation of a two-part tariff can be defined as the amount of money needed to restore the consumer to the position he or she was in prior to its implementation. By this definition the changes in the average customer bills, identified in **Table 6**, represent the welfare change for each group. Switching to the two-part tariff in **Example A** would increase the average monthly bill in the three lowest usage groups, while decreasing the average monthly bill in the three higher usage groups. If these changes were weighted by the number of consumers in each group, the net welfare change for all consumers would be zero. Note that such a result is unrealistic because many consumers would react to the lower marginal price of electricity. However, the analysis does allow us to develop an alternative two-part tariff which would result in an increase in welfare and efficiency.

Table 6
CHANGES IN AVERAGE BILLS

ANNUAL BILLS				
Consumption Groups	**Two-Part Tariff**	**Current Rate Design**	**Differences**	
			Absolute	**Percent**
Lowest 10%	$258	$156	$102	39.65%
10% - 25%	$383	$286	$97	25.31%
25% - 50%	$525	$460	$65	12.31%
50% - 75%	$721	$726	$-5	-0.71%
75% - 90%	$968	$1,059	$-91	-9.40%
Highest 10%	$1,488	$1,749	$-261	-17.52%
MONTHLY BILLS				
Consumption Groups	**Two-Part Tariff**	**Current Rate Design**	**Differences**	
			Absolute	**Percent**
Lowest 10%	$21	$13	$9	39.65%
10% - 25%	$32	$24	$8	25.31%
25% - 50%	$44	$38	$5	12.31%
50% - 75%	$60	$60	$-0	-0.71%
75% - 90%	$81	$88	$-8	-9.40%
Highest 10%	$124	$146	$-22	-17.52%

In interpreting the initial look at consumer welfare the reader is cautioned not to confuse low usage with low income. While there is a positive correlation between income and usage it is not perfect. Our stratification methodology leads to a mix of high and low income households within the 60 usage groups. Even at the aggregated level shown in **Table 7,** the usage groups display a mix of both high and low income households. Therefore, not all low income households are in the lowest usage groups. And some low income households could see a reduction in their electric bills as a result of switching to a two-part tariff. **Table 7** display the income of each the usage groups by quartiles.

Table 7
RESIDENTIAL INCOME PATTERNS

Consumption Groups	First Quartile	Median	Mean	Third Quartile
Lowest 10%	$12,500	$17,500	$26,750	$35,000
10% - 25%	$12,500	$25,000	$30,170	$45,000
25 - 50%	$17,500	$35,000	$36,750	$45,000
50% - 75%	$25,000	$35,000	$43,750	$62,500
75% - 90%	$25,000	$45,000	$50,000	$62,500
Highest 10%	$35,000	$62,500	$61,250	$87,500

An Alternative Two-Part Tariff, Example B

Implementation of a two-part tariff under the restrictive assumption in **Example A** would increase the bills of customers in the lower usage groups. However, their reduction in welfare could be offset in a transparent manner so that both efficiency and equity is maintained. This could be done by imposing a distribution surcharge on the higher usage groups and redistributing it in such a manner than the average customer's bill in each usage group, initially, does not change. Then by relaxing our assumption of no change in consumption it is possible to design a plausible scenario in which a two-part tariff increases total welfare while improving efficiency.

Combining the two-part tariff with a transparent distribution surcharge would leave the bill of those consumers who do not respond to the lower marginal price of electricity unchanged. However, most consumers would respond to the lower marginal energy price and increase consumption. Since such actions are voluntary, the change in the composition of goods and services purchased would increase total welfare. This must be the case otherwise these consumers would not change their consumption patterns. The net overall change in consumer welfare will be positive and the increased use of generation capacity will improve economic efficiency. **Table 8** displays these average changes in consumer welfare by usage group.

Table 8
TWO-PART TARIFF, EXAMPLE B

ANNUAL VALUES							
Consumption Groups	**Total Fixed**	**Transparent Surcharge**	**Adjusted Fixed**	**Marginal Price**	**New Consumption Level (kWh)**	**New Bill**	**Change in Consumer Welfare**
Lowest 10%	$203	$-102	**$101**	$0.033	1,940	$165	$8
10% - 25%	$281	$-97	**$184**	$0.033	3,601	$303	$14
25% - 50%	$358	$-65	**$293**	$0.033	5,485	$474	$24
50% - 75%	$489	$5	**$494**	$0.033	8,089	$761	$40
75% - 90%	$641	$91	**$732**	$0.033	11,347	$1,106	$61
Highest 10%	$961	$261	**$1,222**	$0.033	18,243	$1,824	$102
MONTHLY VALUES							
Consumption Groups	**Total Fixed**	**Transparent Surcharge**	**Adjusted Fixed Charge**	**Marginal Price**	**New Consumption Level (kWh)**	**New Bill**	**Change In Consumer Welfare**
Lowest 10%	$17	$-9	**$8**	$0.033	162	$14	$1
10% - 25%	$23	$-8	**$15**	$0.033	300	$25	$1
25% - 50%	$30	$-5	**$24**	$0.033	457	$40	$2
50% - 75%	$41	$0	**$41**	$0.033	674	$63	$3
75% - 90%	$53	$8	**$61**	$0.033	946	$92	$5
Highest 10%	$80	$22	**$102**	$0.033	1,520	$152	$9

The welfare changes were based on the valid assumption that consumers would react to the lower marginal price of electricity by increasing their consumption. The lower marginal price was based on the assumed Power Exchange price of 2.9 cents per kWh plus a transmission charge of 0.4 cents per kWh. The change in consumption was derived with an assumed price elasticity of -0.24. This estimate was obtained from the literature and verified by analysis of the data set. The change in consumer welfare was found using the following equation, $(\Delta kWh * \Delta Price)/2$.

Table 9 displays the differences in bills for the three types of tariffs discussed in this testimony.

Table 9
COMPARISON OF RATE STRUCTURES

	ANNUAL VALUES								
Consumption Groups	Current Rate Design			Two-Part Tariff Example A (assumed no Δconsumption)				[illegible]	
	Average Use (kWh)	Average Bill	Average Rate	Average Use (kWh)	Average Bill	Average Rate	Change In Welfare	Average Use (kWh)	[illegible]
Lowest 10%	1,680	$156	$0.093	1,680	$258	$0.154	$-102	1,940	
10% - 25%	3,120	$286	$0.092	3,120	$383	$0.123	$-97	3,601	
25% - 50%	4,737	$460	$0.097	4,737	$525	$0.111	$-65	5,485	
50% - 75%	6,955	$726	$0.104	6,955	$721	$0.104	$5	8,089	
75% - 90%	9,731	$1,059	$0.109	9,731	$968	$0.099	$91	11,347	
Highest 10%	15,624	$1,749	$0.112	15,624	$1,488	$0.095	$261	18,243	
	MONTHLY VALUES								
Consumption Groups	Current Rate Design			**Two-Part Tariff Example A (assumed no Δconsumption)**				[illegible]	
	Average Use (kWh)	Average Bill	Average Rate	Average Use (kWh)	Average Bill	Average Rate	Change In Welfare	Average Use (kWh)	[illegible]
Lowest 10%	140	$13	$0.093	140	$22	$0.154	$-9	162	
10% - 25%	260	$24	$0.092	260	$32	$0.123	$-8	300	
25% - 50%	395	$38	$0.097	395	$44	$0.111	$-5	457	
50% - 75%	580	$61	$0.104	580	$60	$0.104	$0	674	
75% - 90%	811	$88	$0.109	811	$81	$0.099	$8	946	
Highest 10%	1,302	$146	$0.112	1,302	$124	$0.095	$22	1,520	

There is an additional benefit of the two-part tariff described in **Example B**, which is a reduction of the CTC. The total CTC developed for illustrative purpose in **Example A** was $4,008,381. In **Example B** the increase in consumption of 6,859 kWh would result in an additional $508,813 worth of generation expenditures, a portion of which would the cost of stranded investments.

Economic efficiency is also improved because the consumer is provided with more accurate price on which to base consumption decisions. Consistent with Staff's 1994 testimony [7], it has been shown here that current rate designs place much of the fixed costs (e.g. nearly all of distribution costs) inappropriately on kWh use. Customers in our data set are in effect paying 9 to 10 cents for using marginal kWh that cost no more than 2.9 cents to produce and in wet winter years with hydro spills a lot less.[8] This leads to potentially massive distortions in energy use -- e.g. people with electric heat "wearing sweaters and freezing in the winter".

Such increases in consumption may not be without additional societal costs. Increased generation may cause additional air quality problems that would need mitigation. These costs have not been included in Staff analysis, but their effects should be examined.

The current rate design is also inefficient because it leads to distorted valuation of the benefits of energy efficiency. Implementation of a two-part tariff would reduce the inaccurate pricing signals. That is, with more accurate energy price signals consumers will make their energy choices based on efficiency, as distinct from energy conservation. Moreover, only efficient price signals will allow for both the use of energy and conservation wherever they are cost beneficial.

Equally important, especially as we look ahead to more reliance on market competition, there is a perverse effect that existing rate designs have had on the incentives of regulated utilities and their affiliates to provide energy efficiency services. As long as marginal rates exceed marginal costs utilities have lost revenues when their customers conserve more energy. Moreover, under proposed CPUC PBR ground rules such revenue losses would not be passed through under automatic adjustment like ERAM and traditional rate of return "true ups" regulations, to other customers. Absent pricing much closer to marginal costs, which eliminates profit losses due to conservation at the margin, there are only two alternatives. Both are very unattractive. One alternative is to recover the revenue losses through the public surcharge thereby substantially reducing funds available for direct provision of energy efficiency and other public goods. The other is to reduce the amount of services utilities provide even though they will be in a position, because of their expertise and reputation advantages, to provide highly desired energy efficiency services in a restructured industry.

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[7] See Michael R. Jaske, Kenneth C. Goeke, Pramod Kulkarni, "Initial Assessment of Consumer Choice For Electricity Services," Docket No. 93-ER-94, October 18,1994.

[8] California Energy Markets indicates western non-firm off-peak prices for California are currently between 5 and 8 mills and peak between 7 and 10.5 mills, i.e. essentially 1 cent or less per kWh (see 3/15, p. 8).

EXPLORATION OF OTHER RATE DESIGN ISSUES

This section reports on exploratory investigations of several current or prospective rate design issues which could not be fully assessed in time or with the data that were available.

Average Rate and Virtual Direct Access Customers

The CPUC has argued that "those customers who elect to remain with their local utility for the purpose of generation procurement and distribution services gain the most startling advantage [from restructuring]. They will be direct beneficiaries of the wholesale competition among generators in that the local utility [which will be known as Utility Distribution Company (UDC)] will simply pass through to its customers prices which it has paid to procure power through the [Power] Exchange." [9] UDC customers will have the choice between two different rate designs. With one option, customers may choose to have their bills computed on the basis of an assumed load profile which matches their monthly energy usage, procured by the UDC from the Power Exchange, multiplied by the Power Exchange's hourly prices. These customers are referred to as "average rate" customers, since the assumed load profile averages the hourly Power Exchange prices. Another option, for those who are willing to consider shifting load in response to the hourly price signals of the Power Exchange is to have these prices passed through directly to them by installing appropriate metering and communication system hardware. Their bills will be the summation of the product of the actual amount of energy used in the hourly period times the Power Exchange's spot price. These customers are referred to as "virtual direct access" customers. The key distinctions are in the use of actual versus assumed hourly load patterns and in the virtual direct access customer's receipt of hourly prices.

The CPUC has identified several benefits of virtual direct access. Such time differentiated pricing gives the customer control over one's own costs and provides "triple benefits". More specifically, they assert that (1) any customer willing to chose virtual direct access and shift load from peak to off-peak can lower one's bill and (2) that other customers staying on average cost rates can have an "exact replica" of their current bill (p. 77). The CPUC is incorrect because the current rate design is not efficient, and retains several cross-subsidies. [10]

To elaborate, on the one hand, it is possible for some customers who are receiving cross-subsidies to switch to virtual direct access and lose out despite shifting load. This is because their load shift savings may not be sufficient to offset the value of their lost cross-subsidies and the higher costs of Real Time Pricing (RTP) metering systems. On the other hand, those customers who are now on the losing end (e.g. those with large relatively flat loads) can lower their bills through virtual direct access without any additional load shifting. This is

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[9] CPUC Decision D. 95-12-063, dated December 20, 1995, page 13.

[10] See Michael R. Jaske, Kenneth C. Goeke, Pramod Kulkarni, "Initial Assessment of Consumer Choice For Electricity Services," Docket No. 93-ER-94, October 18,1994.

because their behavior is already consistent with true energy costs, but they have not received appropriate bill reductions. Moreover, to the extent these flat load customers choose virtual direct access it will shift costs to the average rate customers. That is contrary to CPUC's assertion that average rate customer will not see a change in their bills. The average rate customers cannot be guaranteed an "exact replica" of their current bills without the CPUC dictating to the utilities that this be done, irrespective of the details of various specific restructuring decisions. Indeed because switching to virtual direct access is voluntary, we should expect adverse selection to lead to a disproportionate selection of virtual direct access by flat load customers who will thereby shift costs to high peak load, average rate customers. Ironically, it is these relatively high peak using customers who in many cases are the very ones capable of shifting their load to realize the "triple benefits" touted by the CPUC. But, since they risk a loss, becoming virtual direct access customers and not shifting enough of their load to reduce their bills, such customers are least likely to opt for virtual direct access unless extensive informational programs are developed to ensure that customers understand the consequences of their choices.

Examination of Current Time Of Use Rates

In California very few residential customers have chosen time-of-use (TOU) rates. For one major utility in California only 3.68 percent of its customers voluntarily chose to be on TOU rates. More revealing for purpose of this analysis is the fact that TOU customer loads were not substantially different from the average residential customer. Customers on TOU rates used 15.1 percent of their summer electricity during peak periods compared to 18.7 percent for the average residential customers. TOU customers used 41.9 percent of their winter electricity during partial peak periods compared to 41.5 percent for the average residential customer.[11] The summer peak period for TOU rates is between the hours of noon to 6 p.m. Monday through Friday. The E-7 summer peak rate is 31.5 cents per kWh; the off-peak rate is 8.5 cents per kWh. The E-7 winter peak rate is 11.6 cent per kWh; the off-peak rate is 8.9 cents per kWh. There is also a meter charge of 12.8 cents per day, approximately $46.76 a year.[12]

Staff extracted additional characteristics of TOU customers from the residential data set it created for the analysis of the two-part tariff. In the data set there were 345 survey respondents on TOU rates, representing approximately 2.11 percent of residential customers with a full year of consumption. The TOU customers on average paid 11.0 cents per kWh during the summer months. Non-TOU customers paid 11.6 cents per kWh. Staff believes that this is an indication that the TOU customers did not significantly change their loads after going on TOU rates. Had they significantly changed their loads, one would expect a greater

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[11] Pacific Gas and Electric Company, 1996 TEST YEAR GENERAL RATE CASE PHASE 2 CONSOLIDATED EXHIBIT, Revenue Allocation Workpapers Chapter 2 Customer Loads, p. 7.

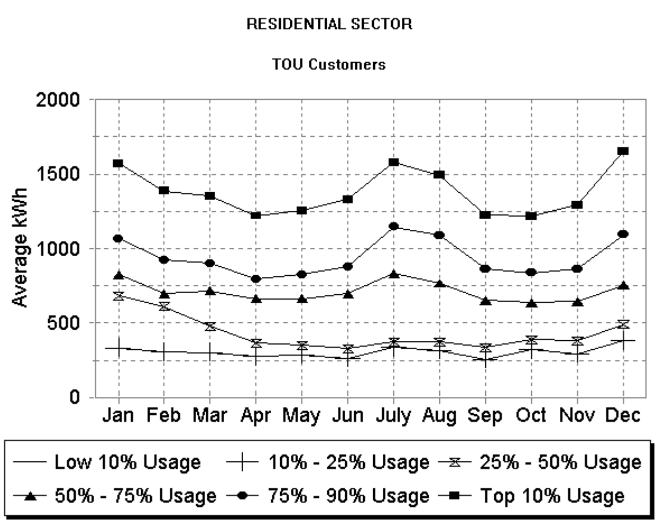
[12] Pacific Gas and Electric Company Rate Schedule, filed December 28, 1995, effective January 1, 1996, CPUC Sheet No. 13943-E.

average price differential between them and non-TOU customers. The benefits gained from TOU rates were a result of the average rate paid in the winter period. TOU customers paid on average 8.2 cents per kWh during the winter months, compared to 11.8 cents for non-TOU customers. The data suggest that customers chose TOU rates as a way to lower their bills by taking advantage of their existing load profiles, without necessarily shifting load.

TOU customers tend to be high usage households. The average TOU customer in the data set used 14,682 kWh a year compared to the average non-TOU customer's use of 6,489 kWh. The average TOU customer's annual expenditure on electricity averaged $1,410 compared to the non-TOU customer's expenditure of $686. The 1990 income of the average TOU customer was $69,036 compared to the non-TOU customer's average income of $44,712. The average TOU customer lived in a 2,200 square foot house compared to the average non-TOU customer's 1,400 square foot house. The average saturation of electric heat for TOU customers was 16.8 percent compared to the average saturation of electric heat for non-TOU customers of 9.1 percent. And the average saturation of electric water heating for TOU customers was 41.3 percent compared to
13.0 percent for non-TOU customers.

Figure 2 displays the monthly electricity consumption of the data set households which were on TOU rates. Note that none of the households in the lowest 10 percent consumption group were on TOU rates.

Figure 2



Customer Response To The Power Exchange Price

Staff would expect that the first customers to take advantage of the Power Exchange's hourly prices would be customers with relatively flat loads. That is, customers with load shapes similar to those of TOU customers. A examination of three customers groups: summer peaking, relatively flat loads and winter peaking, reveals that approximately 50.2 percent of the data set's residential customers have relatively flat monthly loads similar to those of TOU customers. **Figures 3, 4 & 5** display customers monthly usage by consumption group for the three different monthly load patterns reviewed. Of the relatively flat monthly load customers only 4.85 percent of them exhibit the high annual use and expenditures of TOU customers-- 14,682 kWh a year and an annual bill of $1,410. If we assume that those customers with annual bills of more than $1,000 a month might also be willing to risk the variation in the Power Exchange's hourly price to lower their bills, then 13.0 percent of customers may elect to become virtual direct access customers. Customers with less than $1,000 a year expenditures on electricity are probable not going to select virtual direct access because their risk is too great. That is, they risk an increase in their bills because their load shapes are not conducive to the hourly price structure of the Power Exchange.

The Effects of Virtual Direct Access and Aggregation on Average Rate Customers

Consumer actions will be highly asymmetric--weighted more heavily towards avoiding loss than in realizing gain. In confronting risky choices they will, in effect, be risk avoiders when it comes to realizing gain, while being risk seekers when it comes to avoiding loss. [13] Due to the risk avoidance predisposition of consumers we would expect that many of the 50.2 percent of residential customers identified in **Figure** 4 will not try to lower their bills by taking advantage of virtual direct access. This risk avoidance creates an arbitrage opportunity for aggregators. Aggregators will find relatively flat load customers attractive candidates for aggregation, creating a load with a relatively high load factor. Aggregators will also benefit by passing on a smaller amount of savings to the customers in return for reduction of risk. Customers will receive less of a bill reduction than had they chosen virtual direct access; however, the customer may be better off due to the reduction of risk.

Whether a relatively flat load customer chooses virtual direct access or the services of an aggregator the triple benefits noted in the CPUC restructuring decision will not occur. This is because customers taking advantage of hourly price will do so without shifting load, causing average rate customers bills to increase. This can be illustrated by examining the residential data. Residential customers in the data set contributed $11,260,909 towards their utility's revenue

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[13] See Massimo Piattelli-Palmarini, Inevitable Illusions How Mistakes of Reason Rule Our Minds and Richard M. Thaler, Quasi Rational Economics.

Figure 3

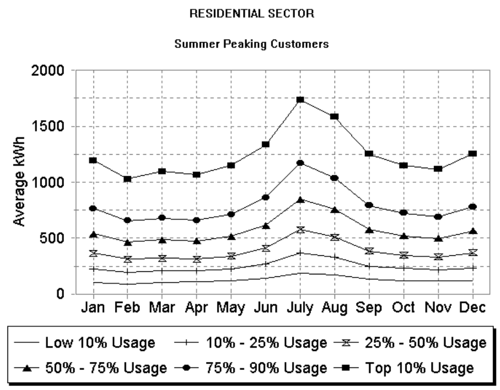


Figure 4

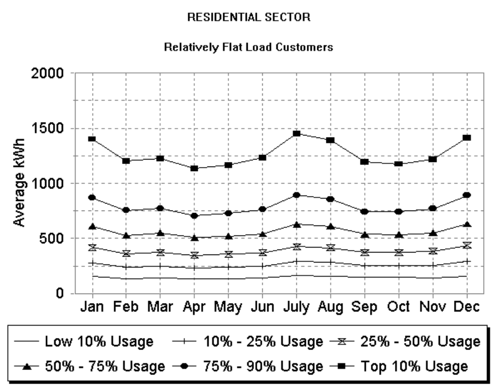
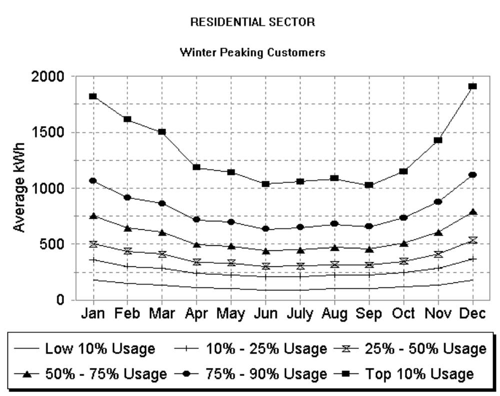


Figure 5



requirement.[14] If all the relatively flat load customers went on TOU rates and reduced their bills without shifting loads, as most of those presently on TOU rates have done, the utility's revenue would fall by $589,133. In order to recoup the difference the utility would have to increase the average rate of non-TOU customers from 10.5 cents per kWh to 11.6 cents per kWh, a 10.5 percent increase. The size of the rate increase for average rate customers would vary directly with the difference between off-peak and on-peak prices and the length of the peak interval.

The adverse selection process inherent in aggregation and virtual direct access will put the UDC at a competitive disadvantage in the restructured electricity market. The UDC is designated as the provider of last resort. That is those who choose not to choose will remain average rate customers of the UDC. As has been shown aggregators will be able to cherry pick the relative flat load customer, leaving the UDC with the higher cost peaking customers. This process will continue as further shifts in customers toward aggregation leave yet higher average cost customers behind for the UDC. The process will stop when only those customers remain for the UDC which no one else wishes to serve. This process will ultimately reveal the true cost of service to all customers, which are now hidden within the current integrated utility.

COMMERCIAL/INDUSTRIAL CUSTOMER RESPONSES

In this section of the testimony Staff examines what are the likely responses to prices and rates by commercial/industrial customers, in shifting consumption patterns and reducing bill impacts?

Introduction

In the new, more competitive environment of the restructured electricity industry, commercial/industrial (C/I) customers will have more choices for electricity service. These choices will include varying levels of service, as well as varying price structures. C/I customers may be offered prices and service tailored to their needs without the need for extensive negotiations with suppliers and without the need to wait for regulatory approval of the terms. However, price will only be one of the criteria that C/I customers use to make decisions about suppliers. Depending on the customer's needs, price may not be the most important criteria.

There has been some speculation C/I customers will respond to the restructured electricity market by significantly changing consumption patterns. At this time, we are unable to show analytically what will happen to electricity prices and how C/I customers may respond. Determining C/I customer responses to a restructured market for electricity would require

[14] This is the same data set Staff used in the earlier sections, that is, it includes only those customers who had a full year of consumption data.

knowing the market clearing price for electricity, the cost of distribution and transmission unbundled from generation, and the cost and duration of the competitive transition charge. Though a moving force behind restructuring is to lower California's relatively high electricity rates, it is possible that some customers may pay more based on their usage and level of service. This is especially true given our discussion of a two-part tariff. If certain C/I customers have been receiving hidden subsidies then we would expect these customers to pay more after restructuring.

We do show that bundled rates are already low for the larger C/I customers. If electricity prices are lower under restructuring, they may not significantly modify their usage. For many smaller C/I customers, rates are relatively high. Reductions in their electricity costs may have a significant impact on their usage.

California Commercial/Industrial Rates Relative to US Averages

Part of the impetus for restructuring is the perception that C/I (as well as all sector) rates in California are much higher than the national averages. In inflation adjusted terms (1993 cents), California average C/I rates in 1975 were approximately the same as those nationally (see **Figure 6**). There was considerable volatility in California C/I rates in the late 1970s and early 1980s that was not experienced nationally. From 1984 to 1995, California average C/I rates have been 2.4 to 3.4 cents per kWh higher than the US average C/I rate excluding California. In 1984, California average C/I rates were about 31.1 percent higher than the US average C/I rate. By 1995, that percentage had increased to 58.2 percent [15].

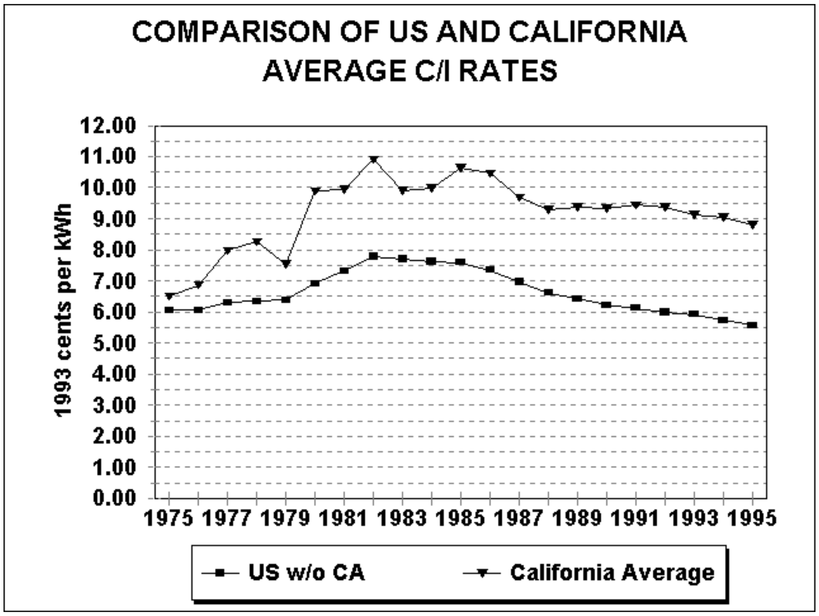
For C/I customers that compete in intrastate markets, this difference between California and national rates may not be a disadvantage. However, for C/I customers that compete in national markets, higher California rates do have an impact. As the California electricity industry is restructured, this difference may drive these customers to seek other options to reduce their electricity bills. These options could include seeking a new, lower cost supplier, contracting with an energy services company to reduce their overall bills, or turning to self generation.

Current Commercial/Industrial Rate Structures

In this section, we examine what existing C/I customers currently pay for their electricity service. We will show that, for the largest C/I customers, average rates are already fairly low compared to small and medium C/I customers. For these large C/I customers, incremental rates are even lower than these low average rates. Based on this, we believe that some large C/I customers will have only a modest incentive to modify their electricity use or to seek alternative suppliers on a price basis. We believe that large C/I customers may choose to

[15] Data for this comparison are from Edison Electric Institute, **Statistical Yearbook** 1975-1984 and 1986-1993 and Energy Information Administration, **Electric Power Monthly**, March 1995, March 1996.

Figure 6



modify their use or seek alternative suppliers for non-price or service related reasons. However, this incentive will be somewhat greater for those large C/I customers not already on special anti-bypass rates or with self generation. On a price basis, small and medium C/I have a greater incentive to modify their use or to seek alternative suppliers.

Based on data in FERC Form No. 1, in 1995 the average C/I customer of the major California IOUs paid between 9.6 and 9.0 cents per kWh (see **Table10**). SDG&E C/I customers paid the least on average, while PG&E and Edison C/I customers paid more. The average sales per C/I customer was the highest in Edison and the lowest in SDG&E. For comparison, the average C/I customer in the U.S. (excluding California) paid 5.8 cents per kWh. For comparison purposes, we show the average system rate for each of the three IOUs and for the U.S. excluding California.

The averages mask considerable dispersion in C/I rate schedules of the IOUs. Each utility maintains a significant number of different rate schedules for their commercial and industrial customers. For example, PG&E has approximately forty and Edison has over one hundred rate schedules (or sublistings) for their commercial/industrial customers listed in their 1995 FERC Form No. 1. (SDG&E does not report detailed rate schedule information in its FERC Form No. 1).

Table 10
COMPARISON of AVERAGE SALES and RATES FOR COMMERCIAL/INDUSTRIAL CUSTOMERS BY UTILITY, 1995

	Average Number of C/I Customers	Average Sales per C/I Customer (in kWh)	Average Rate for C/I Customers (in cents per kWh)	Average System Rate (in cents per kWh)
PG&E	544,467	86,113	9.6	10.2
Edison	477,527	100,624	9.5	10.6
SDG&E	122,160	79,518	9.0	9.8
U.S w/o CA	NA	NA	5.8	6.7

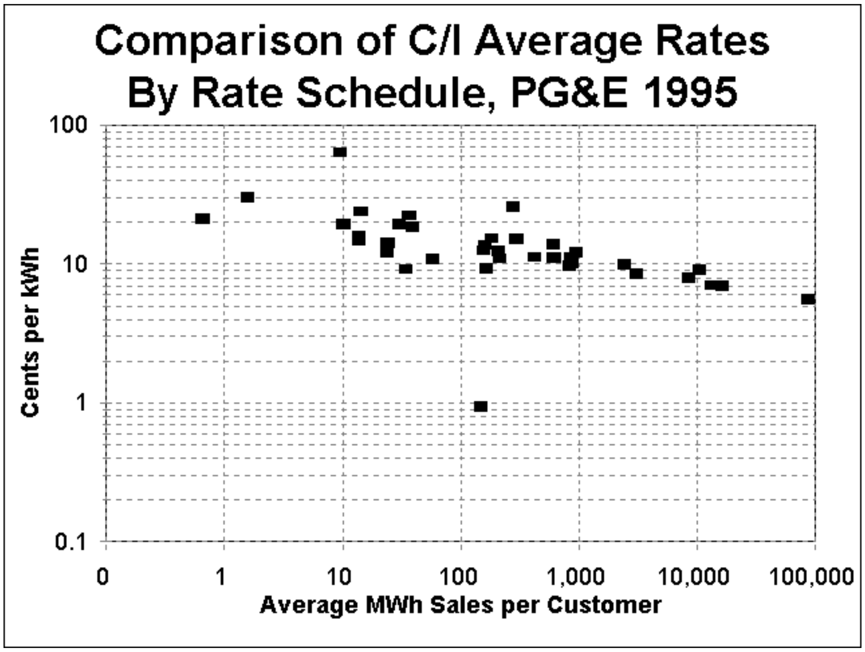
Notes:
1. From 1995 FERC Form No. 1 for each of the respective utilities.
2. The commercial/industrial category includes agricultural customers, sales and revenues.
3. Data for U.S. without California is from "Electric Power Monthly," Energy Information Administration, March 1996. Customer data on a nationwide basis was not available.
4. The average rate includes both the cost of energy and any demand (fixed) charges.
5. Average system rate is total revenue from all customers divided by total sales.
6. In nominal cents per kWh.

Some of this dispersion appears to be correlated with sales per customer. For example, C/I customers on PG&E's rate schedule SA 1 (Standby and General Service) paid as much as 62.5 cents per kWh for average sales per customer of 9,666 kWh. Customers on PG&E's SPEC Contract (special anti-bypass contracts) paid as little as 5.5 cents per kWh for average sales per customer of 88,643,437 kWh. This correlation can be seen more readily in **Figure 7** where we show the relationship using a logarithmic scale of average sales and the average rate paid by customer for the PG&E's C/I customers [16].

The dispersion in average rates for Edison's C/I customers is greater than that of PG&E's. The highest rate paid by an Edison C/I customer was 2,476.5 cents per kWh for average sales per customer of 333 kWh (for CR1-I6B-F-S, large general service customer with interruptible and standby rates), while the lowest is 4.1 cents per kWh for average sales per customer of 94,834,444 kWh (for I-6-SPA-T, large general service customers with interruptible rates and a

[16] This dispersion in average rates by customer account using QFER data was shown in previous studies by the Demand Analysis Office. See Kenneth C. Goeke, "Utility Sales at Risk Under the CPUC's OIR/OII: An Initial Look," Appendix A of "Initial Assessment of Consumer Choice for Electricity Services," October 18, 1994 and James J. Lichter, "The Structure of Electricity Consumption, Self-Generation and Electricity Price in California," August 1994.

Figure 7



spot pricing agreement)[17]. A scatter diagram of average rates for Edison and average sales by rate schedule is shown in **Figure 8**. Again, there appears to be a negative correlation between average rates and average customer sales, though it does not appear to be as strong as that for PG&E.

Staff's previous analysis in ***ER 94*** looked at rates paid by SIC code, so we will not reproduce that analysis here. Here we will use the information provided in the FERC Form No. 1 to look at rates paid by rate schedule. PG&E's largest commercial/industrial customers have demands of 500 kW and above. These customers fall in rate schedules E-19, E-20 and under special anti-bypass contracts (SPEC Contracts). For comparison, we will also look at the characteristics of rate schedules A-10 (Medium Use, less than 499 kW demand) and A-1 (General Service, demand less than 499 kW). In **Table 11** we show the average number of customers, average sales per customer and the average rate paid for each of the rate schedules we listed above. It is clear from this data that customers with higher usage pay less, on average (5.7 cents per kWh), and small general service customers pay more, on average (14.4 cents per kWh), than PG&E's residential customers (12.2 cents per kWh).

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[17]Some rate schedules were excluded from this analysis due to missing information on number of customers or kWh sales. Their totals were included in other schedules.

Figure 8

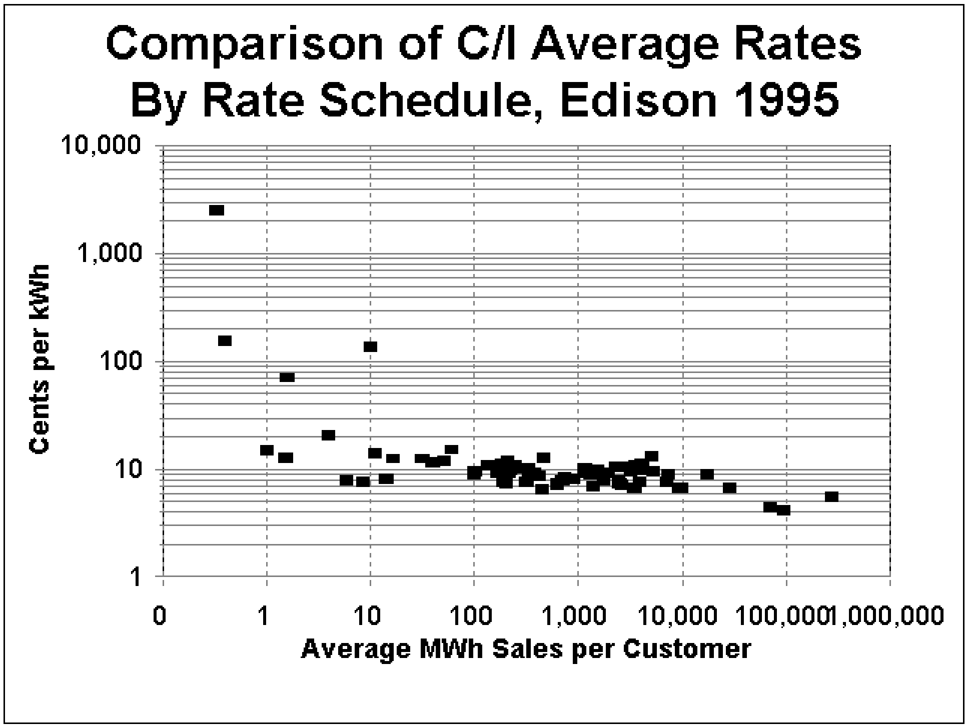
Comparison of C/I Average Rates
By Rate Schedule, Edison 1995
Cents per kWh
10,000
1,000
100
10
1
0
1
10
100
1,000
10,000
100,000
1,000,000
Average MWh Sales per Customer

Table 11
COMPARISON OF COMMERCIAL/INDUSTRIAL RATE SCHEDULES FOR PG&E

Rate Schedule	Average Number of Customers	Average Sales per Customer (in kWh)	Average Rate for Customers (in cents per kWh)
A-1 General Service	347,807	13,799	14.4
A-10 Medium Demand Metered	45,171	216,966	10.9
E-19 500 to 999 kW	12,335	834,238	9.6
E-20 above 999 kW	1,066	13,217,149	7.0
SPEC Contract	16	88,643,437	5.5

Notes:
1. From 1995 FERC Form No. 1.
2. The average rate includes both the cost of energy and any fixed (demand or customer) charges.
3. In nominal cents per kWh.

Small and medium C/I customers may have the greatest potential savings from restructuring. Large industrial customers on rate schedules E-20 and SPEC Contract have smaller potential savings.

One could argue that average rates are not a correct indicator since they include fixed charges that may be unavoidable. A more correct measure of the cost would be the incremental electricity rate. In fact, incremental electricity rates are lower than the averages shown above. The summer peak incremental rate for A-10, medium demand metered, customers is 8.9 cents per kWh, 2.0 cents per kWh lower than the average A-10 rate. In **Table 12**, we show the incremental electricity rates for those rate schedules shown in **Table 11**. On this basis, there may be even less incentive for large and some medium C/I customers to modify their behavior or switch to an alternative supplier.

Table 12
COMPARISON OF COMMERCIAL/INDUSTRIAL INCREMENTAL RATES FOR PG&E

Rate Schedule	Summer (cents per kWh)	Winter (cents per kWh)
A-1 General Service	14.9	10.2
A-10 Medium Demand Metered	8.9	7.2
E-19 500 to 999 kW (Firm)		
Secondary	8.8	6.4
Primary	6.3	5.7
Transmission	8.7	8.1
E-20 above 999 kW< (Firm)		
Primary	8.7	6.3
Secondary	6.2	5.6
Transmission	5.8	5.4

Notes:
1. From PG&E Tariff Schedules effective July 1, 1996.
2. Summer rates are for the peak period. Winter rates are for partial off-peak.
3. Secondary, primary and transmission refer to the voltage level at which customers receives service.
4. In nominal cents per kWh.

Our results here confirm Staff's previous analysis in showing that the largest C/I customers pay considerably less than the average C/I customer. We believe that, on average, the savings from direct access for large C/I customers will be modest. Small and medium C/I customers may realize greater savings and have a greater incentive to seek alternative suppliers or to modify their energy use. Since these small and medium C/I customers have lower demand, we believe that aggregation may be necessary for them to fully realize any savings from a restructured electricity industry.

Other Factors

While we believe that some large C/I customers, particularly those on special anti-bypass rates or with self generation, may not choose new suppliers or modify use based solely on price considerations, they may for other reasons. While electricity is a costly input, it may not be the primary factor of production. We believe that many C/I customers are as concerned with service as they are with price. We believe that qualitative factors, such as perceived reliability or customer service, will play a role in customer retention.

Service and flexibility were important factors to business customers as the telecommunications industry was deregulated. Many large customers sought specialized equipment for their in-house telephone systems. AT&T was unable to provide those systems, so these customers sought other vendors. The primary consideration was to have more flexibility and better service.[18]

Our belief about the role of service in customer satisfaction is confirmed by a recent study done by Satisfaction Works and Bright Line Energy (SW-BLE). Their survey, "The Market for Electric Energy in California," shows that 50 percent of the commercial and 56 percent of the industrial customers surveyed are likely to defect, i.e. look for new suppliers with the coming of direct access. Of the 24 criteria for measuring electrical provider performance, competitive price was ranked 18th by commercial customers and 21st by industrial customers. Customers ranked reliability and customer service related criteria among the top three. [19]

While price appears to be ranked low, the largest performance shortfalls (differences between customers' expectations and their perceptions of utility performance) are in the areas of competitive price and supplier responsiveness to the company's need to lower energy costs. Forty-five percent of industrial and 49 percent of commercial customers would leave for discounts of 10 percent or less. Approximately 90 percent of all customers surveyed would leave for discounts of 20 percent or less. However, when those customers with the greatest risk of defection were given the choice of lower prices or enhanced services, such as better service in the form of guaranteed long term availability of power, backup power capabilities, better customer service, more stable predicable prices, better power quality, custom energy management services to reduce costs, over half chose enhanced services

Those customers that want lower prices are not likely to give concessions, such as real time pricing or load shifting, to get those lower prices. Of the commercial customers that would switch suppliers for a 20 percent discount, only 3 to 7 percent would make a concession to receive that discount. Of the industrial customers that would switch for a 20 percent discount,

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[18] See Gregory B. Enholm and J. Robert Malko, **Electric Utilities Moving into the 21st Century,** 1994, pp. 58-59.

[19] Satisfaction Works and Bright Line Energy, "The Market for Electric Energy in California," February 1996. Their results mirror an earlier residential survey done by Reichman-Karten-Sword, Inc. "Customers are Happy, But How Loyal are They?" **Electrical World**, March 1993, p. 15.

only 1 to 3 percent would make a similar concession to receive that discount. Customers would be more likely to change suppliers than their behavior.

SW-BLE also found that industrial firms were more likely to say that the cost of electricity put them at a competitive disadvantage than commercial customers. This may be due to the interstate competition that many industrial customers face. As we have shown, C/I rates are much lower outside of California.

Given the importance of service to C/I customers, there may be considerable opportunity for energy services companies (ESCOs) to increase customer value. Many C/I customers would be receptive to assistance in lowering operating costs, improving comfort, meeting environmental rules and simplifying their work environment. In fact, the president and CEO of Edison Source, the unregulated energy services subsidiary of Edison International, recently emphasized the importance of an integrated approach to meet the total energy needs of wholesale, commercial and industrial customers. To that end, in June, Edison Source applied to FERC for certification to sell power at market-based rates.[20]

C/I Customer Reactions to Restructured Electricity Markets

As the market opens to competition, it is likely that many large C/I customers will look for new suppliers of electricity. In some cases, their search will be driven by a desire for lower cost electricity. This is especially true for those customers not self-generating or those not on special anti-bypass contracts. As SW-BLE point out, some customers disappointed with their utility's performance will look for some combination of better service, better reliability, and lower prices. In some cases, customers, uncertain about service quality or reputability of non-utility suppliers, will not immediately search for new suppliers, but wait until the market matures.

The C/I customers' search to lower electricity costs has been ongoing. Fifty percent of the industrial firms and 64 percent of the commercial firms surveyed by SW-BLE have considered proposals from firms other than their current energy supplier.

Large C/I customers are actively seeking to reduce their electricity bills. Many have sought agreements with irrigation districts with low industrial rates. For example, Praxair[21] signed an agreement with the Modesto Irrigation District (MID). Praxair stated that, though it would be

[20] PRNewswire, Edison Source Press Release, June 17, 1996.

[21] Praxair is the largest industrial gases company in North and South America.

paying MID its retail industrial rate, its new rate would be lower that its current rate with PG&E.[22]

Foster Poultry Farms (Foster Farms) signed a contract with the Merced Irrigation District. Foster Farms' major concerns with PG&E power were cost and reliability. Foster Farms noted it was at a competitive disadvantage as its electricity rates were twice that of the average paid by other (out-of-state) poultry suppliers.[23]

In some cases, customers may aggregate in order to find lower cost sources of power. PG&E has contracted to supply the Eastside Power Authority (ESPA) through the Power Exchange. ESPA is a joint powers agency formed by the irrigation districts of Delano-Earlimart, Terra Bella, Lindsay-Strathmore and Lower Tule River. They are all former agricultural customers of Edison. Edison has been notified of ESPA's intent to develop its own system and take electrical energy service from the Power Exchange. ESPA will finance and install the $12 million power distribution and control system to distribute energy obtained by Power Exchange to the Authority's customers. A new transmission line will be built along the Friant-Kern Canal right-of-way.[24]

If the relationship between the utility and the industrial customer is amicable, they might negotiate buy-out provisions so that the industrial customer is able to utilize direct access. The industrial customer would pay for any "stranded" costs prior to being allowed freedom to choose suppliers. The Roseville Electric, a municipal utility, and Hewlett-Packard, the utility's largest customer, recently negotiated such an agreement.

RECOMMENDATIONS

Policy Recommendations

Staff believes that a two-part tariff with supplemental low income protection programs should be implemented. Two-part tariffs should also be designed for the commercial and residential sectors. Such tariffs would be a start to implementing efficient pricing as recommended in the ***1994 Electricity Report*** And the illustrative analysis reported here should be carried out in more detail by the Ratesetting Working Group operating under CPUC sanction.

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22 "Application for Rehearing of Decision 96-04-054 of Praxair, Inc. and Destec Power Services, Inc.," May 15, 1996, pp. 16-17.

23 "Joint Application for Rehearing of Decision 96-04-054 by Merced Irrigation District and Foster Poultry Farms," May 15, 1996, p. 6.

24 Jim Carnal, **The Bakersfield Californian**, Jun. 21, 1996 Power Exchange is an energy transaction and power service firm. Its principals have extensive experience in power operations, power services and energy project development, finance and construction.

The efficiency gains of a two-part tariff should not impose undue burden on lower usage groups; that is, these customers should not see drastic changes in their bills. We therefore suggest that implementation should be "accompanied by an opportunity for the consumer to gradually accommodate such costs . . ."[25] As part of the implementation process Staff recommends that the two-part tariff includes a transparent surcharge equal to the amount of the change in the average customer bill in each usage group. The surcharge should be included in the UDC's bill to the customer as a separate line item. This makes the surcharge transparent and non by-passable. Staff further suggests that the surcharge be eliminated over the same period of time as that proposed for the CTC. Its removal would be offset somewhat by the decrease in the CTC.

Staff also recommends that a two-part tariff design be implemented for natural gas. Implementation of a two part-tariff for electricity without a similar tariff structure for natural gas would send incorrect price signals to consumers. The marginal rates in the two-part tariff for electricity would be low relative to the marginal rates for natural gas in the standard tariff. Without implementation of a two-part tariff for natural gas, over consumption of electricity relative to natural gas would occur.

Research Recommendations

Investor owned utilities should conduct similar investigations into efficient pricing mechanisms using their additional resources and in depth data. The Energy Commission and utilities should engage in additional analysis of customer behavior, especially in the area of response to RTP and/or TOU rates. Additional research is also need in the area of response to real time price signals and "smart" appliances. The impacts on load shapes resulting from automatic appliance response to real time price signals will be substantially different from that of Time-of-use rates.

[25] California Energy Commission, ***1994 Electricity Report***, November 1995, p. 36.

Witness Qualifications
for
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I am currently an economist in the Demand Analysis Office of the Energy Forecasting and Resource Assessments Division working on the issues concerning industrial customers.

I graduated from Fresno State University in 1979 with a Bachelor of Arts degree in History and Economics. In 1985 I received my Master of Arts degree in Economics from University of California, Davis.

I have been employed by the California Energy Commission since 1989. I was responsible for out of state power issues and development of resource planning models. I developed financial and rate forecasts for California utilities as part of the Commission's planning functions in the past four Electricity Reports.

Before coming to the Commission, I was employed by Western Area Power Administration as a rate economist. Previous to that I was employed by the Transportation Division of the California Public Utilities Commission as a Public Utilities Regulatory Specialist I and by the Sacramento Municipal Utility District as senior economist. I have also been employed as a lecturer in Economics at the University of California, Davis and Fresno State University.

Witness Qualifications
for
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