Center for the Study of Energy Markets

CSEM WP 133

The Long-Run Effects of Real-Time Electricity Pricing

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June 2004

This paper is part of the Center for the Study of Energy Markets (CSEM) Working Paper Series. CSEM is a program of the University of California Energy Institute, a multi-campus research unit of the University of California located on the Berkeley campus.

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The Long-Run Effects of Real-Time Electricity Pricing

by

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Abstract: Retail real-time pricing (RTP) of electricity – retail pricing that changes hourly to reflect the changing supply/demand balance – is very appealing to economists because it "sends the right price signals." There is, however, frequent confusion between the economic efficiency gains that would result from RTP and the wealth transfers that RTP would create. RTP-induced wealth transfers from producers to consumers were the primary focus of RTP advocates during the 2000-01 California electricity crisis. In this paper, I abstract from such transfers and focus on the long-run gains in economic efficiency that would result from adopting RTP in a competitive electricity market. Using simple simulations, I demonstrate that the magnitude of efficiency gains from RTP is likely to be significant even if demand is not very elastic. Even with demand elasticity of -0.025, the efficiency gains from RTP-adoption for the largest customers is almost certain to exceed the cost of implementing such a system. The simulations indicate that the efficiency gains are increasing, but concave, in the share of demand on RTP and in the elasticity of demand. Also, preliminary analysis of the demand patterns of some large customers indicates that RTP in a competitive market would induce very significant wealth transfers among customers.

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Over the last few years, a great deal has been written about time-varying retail pricing of electricity. Many authors, myself included, have argued that real-time retail electricity pricing (RTP) – retail prices that change very frequently, *e.g.,* hourly, to reflect changes in the market's supply/demand balance – is a critical component of an efficient restructured electricity market. During the California electricity crisis in 2000-2001, RTP boosters pointed out its value in reducing the ability of sellers to exercise market power. While nearly all economists have supported RTP conceptually, Ruff (2002) among others has argued that it is important to distinguish between RTP's long-run societal benefits and the short-run wealth transfers it might bring about. In particular, the reductions in market power primarily prevent a short-run wealth transfer from customers to generators, though the transfers can still be quite large.

In this paper, I estimate the magnitude of the potential long-run societal gains from RTP, abstracting from market power issues and short-run wealth transfers in general. I do this by formulating a model of competitive electricity generation with demand and production costs based on actual data from U.S. markets. I solve computationally for the model's long-run competitive equilibrium, with the results indicating the amount of each possible type of capacity that would be built, the prices that would be charged to customers on RTP and on flat-rate service, and the total social surplus that would be generated by the system. The model also allows estimation of the transfers that would occur among customers if customers on RTP had demands that were (absent RTP) peakier or flatter than customers not on RTP.

The estimates indicate that RTP would substantially reduce peak electricity production and thereby reduce the use of low-capital-cost/high-variable-cost peaker generation. The social gains from RTP for at least the largest customers in the system are estimated to far outweigh reasonable estimates of the metering cost. The magnitudes of the social gain are sensitive to the demand elasticity that is assumed, but the results indicate that even with quite small elasticities, the benefits are substantial.

The estimates also suggest that a change to RTP could, in the long run, have significant redistributive effects among customers. RTP would end the cross-subsidy that currently takes place from customers with relatively constant demand over time to those whose demand has significant peaks coincident with the systemwide demand peaks. The potential for ending this cross-subsidy could be a significant political impediment to implementation of RTP.

Section I presents the economic model that is the basis for simulations. Section II explains the data used in the simulations and the process used to compute long-run equilibria. The results of the simulations are presented and their implications discussed in Section III. In section IV, I extend the basic model to evaluate the transfers that would results from RTP if some customers have substantially flatter or peakier demand than others. Section V discusses a number of factors that are omitted from the simulations and suggests how those factors are likely to affect the results. I conclude in Section VI.

I. Model of Long-Run Competition in Electricity Markets

The model that is the basis for the simulations is adapted from Borenstein and Holland (2003, hereafter BH). It assumes a simple competitive wholesale and retail market structure. The retail structure is identified only by the way in which it charges end-use customers for electricity, using a flat rate for one group of customers and RTP for the remaining customers. The price(s) charged to each of the two groups allow the retailer to exactly break even on service to that group. Throughout the analysis, I take the allocation of customers between the two groups to be exogenous, though I discuss later incentives for a customer to move to RTP. As in BH, the retail pricing can be interpreted as reflecting the outcome of competition among many retail providers, but it also could be interpreted as a single regulated retail provider that is required to exactly cover its costs and required not to cross-subsidize between flat-rate and RTP customers. Following BH, I assume for simplicity that retailers have no other transaction costs.[2]

I assume free-entry of generators of three different types. Generation exhibits no

[2] Joskow and Tirole (2004) extend the BH model by allowing retailers to charge two-part tariffs and by examining the competitive retail market when customers have different demand patterns.

scale economies, with each generation unit having a capacity of one megawatt. The types of generation differ in their fixed and variable costs, higher fixed costs being associated with lower marginal cost of production. For generator type j, annual generator costs are modeled as a fixed cost plus variable costs that are linear in the number of megawatt-hours produced during the year, $TC_j = F_j + m_j \cdot MWh_j$. Startup costs and restrictions on ramping are not considered, an issue discussed in section V. Parameters used for this and all other aspects of the simulations are discussed in the next section.

Demand is modeled as constant elasticity, using a range of possible elasticities. Within any one simulation, demand is first assumed to have the same elasticity in all hours. I then consider the effect of demand elasticity varying positively or negatively with the level of demand. The level of demand in each hour is taken from the distribution based on the actual levels of demand in various US electricity regions, as explained in the following section. Cross-elasticities across hours are assumed to be zero, another issue discussed in section V.

Some proportion of customers, α, are on real-time pricing, and the remainder are on flat-rate service. For now, I assume that all customers have identical demand up to a scale parameter, an assumption that I relax in section IV. Thus, following BH, if the total demand in hour h is $D_h(p_h)$ and the flat-rate service customers are charges $\bar{p}$ in every hour, the wholesale demand is

$$\tilde{D}_h(p_h, \bar{p}) = \alpha \cdot D_h(p_h) + (1 - \alpha) \cdot D_h(\bar{p}). \qquad [1]$$

In this case, demand is modeled as constant elasticity, $D_h(p_h) = A_h \cdot p_h^{\epsilon}$. In later simulations, demand elasticity is allowed to vary across hours, ϵ_h.

Under these assumptions, for any set of installed baseload, mid-merit, and peaker capacity, K_b, K_m, K_p, there is a unique market-clearing wholesale price in each hour, provided that total installed capacity exceeds demand from flat-rate customers in every hour, $K_b + K_m + K_p > (1 - \alpha) \cdot D_h(\bar{p}) \ \forall \ h$. In the following section, I discuss the algorithm for finding the short-run equilibrium for any set of installed capacity and the long-run equilibrium allowing capacity to vary. In presenting the algorithm, I demonstrate that there is a unique long-run equilibrium.

In addition to establishing long-run equilibria for any $0 \leq \alpha < 1$, it will be important, as a baseline, to determine an equilibrium with no customers on RTP. The model above is not applicable to a market with no RTP customers, because without RTP there is no short-run demand elasticity, so in order to meet demand in all hours, sufficient capacity must be built so that the market always clears "on the supply side," *i.e.,* at a price no greater than the marginal generation cost of the technology with the highest marginal cost. Such an organization requires some sort of additional wholesale payment to generation in order to assure that demand does not exceed supply in any period and, at the same time, that generators' revenues exceed their variable costs over a year by an amount sufficient to cover their fixed costs.

It is straightforward to show that the annual capacity payment that assures sufficient generation and the optimal mix of generation is equal to the annual fixed costs of a unit of peaker capacity. To avoid distorting the mix of capacity, this payment is made to all units of capacity, regardless of type.[3] The payment is financed by increasing the price of the flat-rate electricity service until it generates sufficient revenue to cover the capacity payments. That is how simulation of the baseline flat-rate service is implemented in the following section.

II. Data, Model Details and Solution Algorithm

The value of the simulation results depends on the realism of the underlying assumptions. In this section I describe in detail the modeling of demand and supply, and then the algorithm for finding the long-run competitive equilibrium. I first present the details of the model, and then discuss the data used to parameterize the model.

[3] This would also be the outcome if the wholesale price exceeded the marginal cost of the peaking generation only in the highest demand hour of the year, and the price in that hour was equal to the marginal cost of the peaker plus its annual fixed cost.

Demand, Supply and Equilibrium Modeling

Within each hour, each customer's demand is modeled as constant elasticity. For now, each customer i is assumed to have a demand that is simply a fixed proportion, γ_i, of total demand. In section IV, I consider the effect of customers having different demand patterns. In the base simulations, I assume that total demand has the same elasticity in all hours, but this is later relaxed to allow elasticity to vary positively or negatively with the overall demand level.

Given an elasticity for a certain hour, demand is fully specified by one price/quantity anchor point. I assume that at a given constant price (discussed next), the anchor quantity demanded takes on a distribution equal to the actual distribution of quantities demanded from a certain electricity control region.

The constant price used to specify the anchor points is chosen to be the price that would allow producers to break even if it were charged as a flat retail price to all customers. This is not the actual flat rate (or time-of-use rate) that was charged to customers during the observed period from which the demand distribution data are taken. The difference, however, will not substantially change the results for two reasons. First, at the low elasticities I consider in the simulations, a change of 10%-20% in the base flat rate that I assume (which is the magnitude of the potential difference between the rate assumed and the actual flat rate in use) will change quantity demanded very little. Second, and more important, the overall level of base demand is just a scale factor in the simulations. The value of using an actual distribution comes from accurately representing the *shape* of the distribution; that changes negligibly with the assumption made about the level of the flat retail rate.

The aggregate demand function for hour h can be specified as $D_h(p_h) = A_h \cdot p_h^{\epsilon_h}$, where elasticity may or may not vary by hour depending on the simulation run. For any share of demand on RTP, α, the demand from customers on RTP is then $D_h^{RTP}(p_h) = \alpha \cdot A_h \cdot p_h^{\epsilon_h}$ and the demand function for customers on flat rate service is $D_h^{flat}(\bar{p}) = (1-\alpha) \cdot A_h \cdot \bar{p}^{\epsilon_h}$. The aggregate demand in the wholesale power market is then $\tilde{D}_h(p_h, \bar{p}) = \alpha \cdot A_h \cdot p_h^{\epsilon_h} +$

$(1-\alpha) \cdot A_h \cdot \bar{p}^{\epsilon_h}$.

Once the wholesale demand function has been specified each hour, that can be combined with the production technologies to calculate the long-run equilibrium capacity of each technology type. Note that from any given baseload, mid-merit, and peaker capacities, K_b, K_m, K_p, one can determine a short-run industry supply function and therefore wholesale prices for each hour. From those prices, one can calculate the profits of owners of each technology type. In the long-run each technology type is built to the point that one more unit of that capacity would cause profits of all owners of the capacity to be negative. So, the goal is to identify the mix of capacity that causes this condition to hold for all three technologies simultaneously.

At first, this might seem difficult, and it might seem that there could be multiple long-run equilibria or none, but in fact there is a unique technology mix that satisfies this condition. To see this, begin with the peaker technology which, if it is used at all, will be used in the highest demand hour. It is straightforward to find a unique long-run equilibrium if supply is restricted to use only the peaker technology. One simply expands the quantity of peaker capacity, recalculating the associated short-run equilibrium with each increment in capacity, until expansion of capacity by one more unit, causes profits to go negative. Call the capacity level that satisfies this condition K_{tot} since that will generally turn out to be the equilibrium total amount of capacity.

In this peaker-only equilibrium, all rents to generators are earned when production quantity is equal to K_{tot}. In hours with lower equilibrium quantity, price must be equal to peaker marginal cost. Now, begin substituting mid-merit capacity for peaker capacity. Once built, the mid-merit capacity will all be used in any given hour before any of the peaker capacity is used; it is lower on the supply function than the peaker capacity. The key is to recognize that substituting mid-merit for peakers units, holding total capacity constant, does not change the rents earned by the remaining peaker units. In fact, so long as one peaker unit remains, the rents it earns are unchanged by substituting lower-MC technologies for the other units.[4]

Continuing to substitute mid-merit for peaker units will drive down the equilibrium profits of mid-merit units until one more unit would drive the profits of all mid-merit units to be negative. Call the largest capacity of mid-merit units that still earns positive profits, K_{bm} because this will generally turn out to be the total of the baseload and mid-merit capacity. Next, begin substituting baseload capacity for mid-merit units. Note that this does not change the rents to mid-merit units. Continue this substitution until one more baseload unit would drive baseload profits negative. This is K_b. Then, $K_m = K_{bm} - K_b$ and $K_p = K_{tot} - K_m - K_b$. These are the unique long-run competitive equilibrium capacity levels for a given set of available technologies, share of customers on RTP (α), and flat rate ($\bar{p}$).

This equilibrium, however, may not satisfy the retailer breakeven condition, so one must calculate the profits retailers earn on flat rate customers in this equilibrium. If it is not zero, then one adjusts $\bar{p}$ up or down and resimulates capacity. When the resulting equilibrium yields zero profits for retailers as well as generators, this is the unique long-run competitive equilibrium in the generator and retailer markets given the set of available technologies and share of customers on RTP (α). Using this supply function, one can then calculate the equilibrium distribution of prices, loads (quantities), and the consumer surplus for each group.

Data Inputs for Simulation

The critical inputs for the simulation are a load profile (frequency distribution of quantities demanded in an actual system), demand elasticities, and cost characteristics of the production technologies.

The load profile determines the distribution of quantity demanded and the flat rate

[4] This description assumes that equilibrium capacity investment includes at least one unit of each type of capacity. If peaker capacity is dominated by mid-merit or baseload for even the least utilized peaker unit, or if mid-merit is dominated by baseload for the least utilized mid-merit unit, then the same process is followed omitting the dominated technology.

when all customers are on flat-rate service, as described in the previous section. For the simulations presented in here, I use two years of hourly load data from the California Independent System Operator, November 1998 to October 2000. This is scaled – each period set to 30 minutes in this case – to correspond to one year. The first summer in this period is lower-than-average demand and the second is higher than average. I've carried out the same analysis using four-year datasets from the ECAR and NPCC regions with very similar results. As pointed out earlier, the importance of the load profile used is in its shape, *i.e.,* the share of hours at different relative demand levels. The results of the simulation are, by construction, invariant to rescaling of demand in all hours by a constant factor.[5] It appears that load profiles don't differ that much in shape from one control area to another.

Electricity demand elasticities are a subject of nearly endless contention. The relevant elasticity would be a short-run elasticity in the sense of the customer's ability to respond to potentially large hourly price volatility, but still recognizing that customers would know well in advance that prices could be quite volatile. The actual elasticity will depend in great part on technology, as automated response to price changes will surely become easier over time. I simulate for a fairly wide range of elasticities from -0.025 to -0.500. The range -0.025 to -0.150 illustrates the likely impact of RTP in the short run and under current available technologies for demand response. Probably the two most current and relevant sources for elasticity estimates, Patrick and Wolak (1997) and Braithwait and O'Sheasy (2002), derive estimates that span this range. In the longer run, however, real-time demand response will become easier to automate and larger elasticities might be expected, so I include results using -0.3 and -0.5 as well. All demand levels are calculated based on the full retail price, which is assumed to be the cost of power plus $40/MWh for transmission and distribution (T&D).[6]

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[5] To be precise, prices are homogeneous of degree zero, and quantities and capacities are homogeneous of degree one in such a demand-scaling factor.

[6] I assume that the T&D charge is not time-varying. T&D could also be subject to real-time pricing if capacity constraints become binding at some times.

Table 1: Generation Costs Assumed in Long-Run RTP Simulations

Generation Type	Annual Capital Cost	Variable Cost
Baseload	\$155,000/MW	\$15/MWh
Mid-merit	\$75,000/MW	\$35/MWh
Peaker	\$50,000/MW	\$60/MWh

The assumptions about production technology are presented in Table 1. They are intended to represent typical capital and variable costs of baseload, mid-merit, and peaker technologies, corresponding roughly to coal, combined-cycle gas turbine, and combustion turbine generation. The numbers were derived from conversations with industry analysts. The variable costs depend on fuel prices, and are meant to include variable O&M.[7] The annual fixed costs are more difficult to determine precisely in part because they depend on the cost of capital and on the rate of economic depreciation of the plant. These figures appear to be in what most industry analysts would consider to be a reasonable range.

Two further comments on plant costs are warranted. First, the results are not particularly sensitive to the exact cost assumptions on the baseload and mid-merit technology. The different effects of RTP under varying assumptions on elasticity and the share of customers on RTP are driven mostly from changes in the amount of peaker capacity that is built. In future versions, I will include a range of cost assumptions. Second, this paper presents an easily-replicated algorithm for analyzing the long-run effect of introducing demand elasticity. For whatever cost assumptions the policy analyst believes are appropriate, this technique can be used to analyze the long-run implications.

III. Simulation Results and Implications

The first line of Table 2 presents the equilibrium flat rate (\$79.13/MWh, which in-

[7] The price of natural gas is assumed to be \$4.25/MMBtu and variable O&M is assumed to be \$1/MWh. The implied price of coal depends on the heat content of the coal.

cludes \$40/MWh for transmission and distribution), as well as the capacity that is utilized in efficiently providing the demand under the flat rate, and the total energy consumed and cost of that energy. The remainder of the table presents the equilibrium capacities and information about equilibrium price distributions under scenarios with varying proportions of customers on RTP and with those customers exhibiting various demand elasticities. Within each simulation, demand has the same elasticity in all hours.

It is apparent from Table 2 that with even moderate demand elasticity, RTP will significantly change the composition of generation. The greatest effect will be a large decline in the amount of installed peaker capacity. Mid-merit capacity would likely also decline and baseload capacity would increase, though these changes would be small in comparison to the potential for drastic reductions in peaker capacity. Figure 1 shows the load duration curves for simulations with varying elasticities and one-third of customers on RTP. Note that in the upper left hand corner, the curves flatten out at different load levels, with lower peak load levels associated with greater demand elasticity. For demands in these regions, the market clears "on the demand side," *i.e.,* on the vertical portion of the supply curve (constant quantity, varying price).

A question that frequently arises with RTP is how high prices could get and whether "bill shock" during a high-price month would undermine the program. This concern, of course, is greatly mitigated by forward contracts and other financial instruments, as explained in Borenstein (forthcoming). Customers that hold fixed-quantity forward contracts can eliminate most price risk without reducing the strong price incentives on marginal purchases.

Setting aside hedging instruments, however, it is apparent from Table 2 that an RTP program could yield very high prices for a few hours. With very inelastic demand, the prices would be extremely high in some hours. But taken in the context of the annual bill, even the very high prices seem more feasible. With a demand elasticity of -0.1, the highest price hour would amount to 1.6% of the annual bill or around 16% of a typical peak-month bill under fixed rates.[8] The 10 most expensive hours, if they all occured in a single month, would account for a bit more than half of a peak-month bill under fixed rates. Although these amounts would be noticeable in monthly bills, the suggestion that a customer would find that half or more of its *annual* bill occurs in just a few hours is not consistent with my findings.[9]

The overall effect of RTP on social welfare is presented in Table 3. It is immediately clear that the surplus gains from real-time pricing are substantial, even if demand of customers on RTP is quite inelastic. With an elasticity of only -0.025, the surplus gain from putting one-third of demand on RTP, shown in column C, is over $100 million per year. To give these figures some context, in 2001 the state of California appropriated $35 million as a *one time* cost of installing real-time meters for the largest customers in the state, representing slightly under one-third of total demand. That isn't the only cost of switching these customers to RTP, since billing systems must be changed as well, but there are also other benefits to the meters, including remote meter reading that can yield big labor savings. Furthermore, as discussed in section V, the long-run energy market impact analyzed here is only one part of the value of RTP.

It is also clear that the total surplus gains from RTP are highly non-linear in both the elasticity of demand and the share of demand that is on RTP. There is diminishing returns to both greater elasticity and a greater share of demand on RTP. For most elasticities, putting one-third of demand on RTP achieves more than one-half the benefits of putting all demand on RTP. For any given $\alpha > 0$, a demand elasticity of -0.05 generates more than half the benefits of a demand elasticity of -0.15.

Decomposing the change in total surplus reveals two effects that BH demonstrate theoretically. First, flat-rate customers are made better off by other customers moving to RTP. Column F calculates the "per capita" benefit for a hypothetical customer who

[8] In the CAISO, system usage in the peak month is about 10% of annual consumption.

[9] Note that unlike the surplus comparisons I make below, this comparison is to the total bill including non-energy (T&D) components of the bill. This seems appropriate given that the concern is bill shock. Roughly half of the total bill is energy and the remainder is T&D.

makes up 0.001% of the total demand ($D_h(p_h)$) in any given hour.[10] This customer on flat rate billing benefits as an increasing share of other customers moves to RTP. This effect is frequently argued by parties who advocate subsidizing RTP participants.

A second effect, however, may suggest the opposite policy: as demonstrated theoretically by BH, customers moving to RTP harm other customers who are already on RTP. This is shown numerically in column H, which presents the "per capita" benefit of a customer (again representing 0.001% of total demand) on RTP when the total share of customers on RTP is the α in column B. We see that the benefits to a customer on RTP decline as more customers switch to RTP. In fact, the overall externality from a group of customers moving to RTP can be positive or negative, as shown in column J.[11]

Elasticity Varying with Demand Level

In the simulations presented thus far, the elasticity of demand has been the same in all periods, the case in which BH show that the equilibrium flat rate will be equal to the optimal flat rate. BH also show that if demand elasticity is greater in high-demand periods than in low-demand periods, the equilibrium flat rate will be below its optimal level. BH demonstrate that in that case it is theoretically possible that moving more customers on to RTP could lower long-run equilibrium total surplus.

I simulate this case by allowing elasticity of demand to vary with the level of demand, where the level is indicated by the quantity demanded if all customers were charged the flat rate.[12] The elasticity of demand varies linearly with demand level, in this case from 50% of the original demand elasticity for the lowest demand level to 182% of the original demand elasticity for the highest demand level. These boundaries were chosen so that the

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[10] This would be a customer with a peak demand of about 450kW. In California, there are approximately 8,000 customers of at least this size.

[11] BH show that the net externality from a *marginal* change in α is zero when demand in all periods has the same elasticity. There is a non-zero net externality in the cases shown here because the change is not incremental: Some of the externality of any one customer switching to RTP is captured by other customers in the switching group, so is internalized by the group as a whole.

[12] As explained above, this is by assumption the actual CAISO load during each hour.

demand-weighted average elasticity is equal to the original demand elasticity in order to allow some comparability to the previous simulations.

Omitting a few of the columns, table 4 presents results comparable to tables 2 and 3, but for a simulation in which demand is more elastic at higher demand levels. In fact, the introduction of RTP yields greater benefits in this case than the base case in which elasticity is the same in all periods. The reason is clear from looking at the equilibrium capacities. Elasticity in the peak periods is what drives the reduction in peaker capacity when customers move to RTP. This effect is larger when demand elasticity is greater in the peaks. So, having greater elasticity in peak periods means both greater demand response when there is more demand and a larger change in the equilibrium level of capacity, both of which contribute to a greater surplus gain from moving to RTP.

Table 5 presents the opposite case, in which demand is more elastic in low-demand periods than in high demand periods. The elasticity of demand varies linearly with demand level, in this case from 130% of the original demand elasticity for the lowest demand level to 50% of the original demand elasticity for the highest demand level. These boundaries were again chosen so that the demand-weighted average elasticity is equal to the original demand elasticity.

BH demonstrate that when elasticity is greater in low demand periods, the equilibrium flat rate will be above optimal and increasing the share of customers on RTP must necessarily increase total surplus. Nonetheless, the surplus gains in this case are smaller than in the base case, and much smaller than in the case in which demand is more elastic at peak times. The result follows intuitively after recognizing that inelastic demand during peak times means that RTP has less effect of reducing the amount of peaker capacity necessary to meet demand.

IV. Wealth Transfers From Increasing Share on RTP

To this point, I have assumed that all customers have the same demand profile, *i.e.*, that customer i's demand in any period h is just $\gamma_i D_h(p_h)$. In reality, some customers have demands that differ substantially from a fixed proportion of the system demand. Some customers' demands climb proportionally more during system peak times than the system as a whole. Other customers have flatter demands, which vary less than the system as a whole.

To characterize these differences, I introduce the concept of a "demand β," which represents the degree to which a customer's demand covaries with the system demand. The concept is analogous to the financial β concept which represents the degree to which the return on an asset covaries with the return on the stock market as a whole (or the return on all societal capital). Normalizing for varying customer average demand levels, I define the demand β implicitly as

$$\frac{D_{hi}(\bar{p}) - \bar{D}_{hi}(\bar{p})}{\bar{D}_{hi}(\bar{p})} = \beta \frac{D_h(\bar{p}) - \bar{D}_h(\bar{p})}{\bar{D}_h(\bar{p})} + \epsilon_{ih} \qquad [2]$$

where $\bar{D}_h(\bar{p})$ is the average system demand over all hours customer i is in the sample and $\bar{D}_{hi}(\bar{p})$ is the average demand of customer i over all hours it is in the sample.[13] Using this definition, a customer with $\beta_i = 1$ has a demand profile that is equal to a fixed proportion of the system demand plus an error that is orthogonal to system demand. The demand of a customer with a $\beta_i = 0$ is uncorrelated with system demand; it is just a fixed proportion of the average (over all hours) system demand plus an error uncorrelated with system demand. A $\beta_i > 1$ indicates a demand that is "peakier" than the system as a whole and a $\beta < 1$ indicates a demand that is less "peaky" than the system as a whole.

Note that this characterization of demand heterogeneity involves only demand *levels*, not demand *elasticities*. All customers are still assumed to have the same demand elasticity. Thus, changes in the effect of putting customers on RTP are not due to differences among customers in demand elasticity. Still, the βs of customers on RTP do affect efficiency as well

[13] Note that in this equation and in the estimation below, I am assuming that the data are derived from a period in which all customers face the same constant price. In future versions, I intend to correct for the actual rate schedule that the observed customers faced. Under the assumption of fairly inelastic demand, I expect this will have little effect of the implied βs, because most of the observed customers faced "time-of-use" rates where the peak to off-peak variation was relatively small. Ignoring this factor probably means that the estimates discussed below are systematically downward-biased estimates of the βs. None of the observed customers faced RTP tariffs.

as wealth transfers, because they determine how much customers on RTP are consuming at peak times when demand elasticity has the greatest efficiency effect. For instance, if customers on RTP have $\beta > 1$, then they are consuming a disproportionate share of output at peak times when demand changes have the greatest effect, so there is a greater efficiency gain of putting them on RTP than if they had $\beta < 1$, even if the demand elasticities do not vary across customers.

This analysis is important not just for determining the short-run effects on efficiency and on equity, *i.e.,* understanding the size of the cross-subsidy that exists under flat rates and that would be reduced if customers with flat demand profiles switched to RTP. It is also important, because in a market with retail choice, customers with $\beta < 1$ will have an additional incentive to switch to RTP. These customers might switch primarily to end their cross-subsidization of customers with higher βs, not with the goal of responding to real-time price variation in a way that would improve efficiency.

How much does demand peakiness actually vary?

Before turning to the results of these simulations, it is useful to get an idea of the range of βs that might exist. I have obtained customer-level data from a major California utility on nearly 400 large customers that have real-time electricity meters. The data cover June 2001 to August 2003, though not all customers are in the dataset for that entire period either because they opened or closed during that period, or because they did not have the real-time meter for that entire period. For the 317 customers for which there are at least 8760 hours (1 year) of data, I have estimated equation [2] by OLS, using the utility's system load to form the right-hand side variable.

The unweighted mean of the 317 β estimates is 1.15 and the median is 1.17, suggesting that the demands of these companies are on average somewhat peakier than the utility's system demand as a whole at the time of system peaks. The estimated βs vary widely, indicating that there is great variation in the degree to which large customer demands covary with system demand. The 25th and 75th percentiles of the β estimates among the 317 customers are 0.54 and 1.83, respectively. About 8% of these customers have negative

βs and nearly 20% have $\beta > 2$. The minimum is -2.93 and the maximum is 3.42. There is room for a lot more exploration of these results, but the clear inference is that there is quite a bit of variation in the degree to which consumption of different customers is correlated with total system consumption.

Transfers from RTP

The wealth transfers from RTP depend on the βs of the customers who are on RTP. To simulate these effects, the aggregate demand of customers on RTP was set to have a given β (shown in the table) and that aggregate demand was subtracted from the system demand, leaving the remaining demand with an "offsetting" β. Values of β for customers on RTP are constrained not to be too far below one, particularly if α is large, because the quantity consumed by customers on RTP is constrained to be between zero and the entire system demand. Thus, I drop simulations of the case in which nearly all customers are on RTP, since the β of the aggregate demand on RTP in those cases must necessarily be very close to one.

Table 6 presents the results of simulations in which the β of aggregate demand of customers on RTP is less than one.[14] Comparing the results in this table with those in Table 3, two things are immediately apparent.

First, the total efficiency gain is somewhat smaller when the customers on RTP have $\beta < 1$ than when they have $\beta = 1$. This is because the main source of efficiency gain is from aggregate demand at peak times exhibiting elasticity. Note that the peaker and total capacity decline less than in the base case ($\beta = 1$). With $\beta < 1$, less of the demand at peak times is attributable to customers on RTP (even prior to the RTP incentive), so there is less gain.

Second, the overall gains in total surplus could be much smaller than the transfers. For a customer with a very low β, the private gains from going on RTP could be attributable

[14] I have simulated for $\beta > 1$ as well, but customers with high βs are unlikely to be the majority of customers that switch to RTP.

more to ending the implicit subsidy under flat-rate pricing than to actual efficiency gains. This effect is pointed out in Borenstein & Holland (2003b) along with the observation that if there are costs to switching to RTP (*e.g.,* installing meters), then there could be excessive switching from a total surplus perspective.

Note that this simulation captures heterogeneous time-varying *levels* of demand, or demand profiles, across customers, but does not capture heterogeneous demand elasticity across customers. It might be that those switching to RTP would be more able to respond to price variation than the population as a whole, which would enhance the efficiency effect of implementing RTP.

V. Limitations of the Model

Though these illustrations are useful in giving an idea of the potential gains from RTP, they don't take into account all aspects of electricity markets. Incorporating many of these characteristics will be challenging, but it is clear even without that additional analysis that these simulations are likely to understate the benefits of RTP.

The most important area of omission is the stochastic elements of supply and demand. The model does not incorporate the unpredictability of demand or the probabilistic outages of generation supply. Currently, responses to these stochastic elements of the supply/demand balance are addressed almost entirely with supply adjustment. Responding entirely on the supply side is clearly not the most efficient way to address such outcomes.

Including RTP in system balancing will further enhance system efficiency. It seems almost certain that RTP would decrease system peak loads, so using standard proportional reserve rules, it would reduce the amount of reserve capacity needed and the payments for that capacity. More importantly, RTP would increase the responsiveness of demand to system stress and thus would reduce the level of reserves needed for any given level of demand. In economic terms, RTP would not just shift demand to the left at peak times, it would make demand more price elastic, so more balancing could be accomplished with less supply-side adjustment. Likewise, incorporating generator outages raises the benefits of demand responsiveness.

Assuming competitive supply, an upper bound on the "reserves cost" savings from RTP is the total cost of reserve payments. In most systems, operating reserves average 5-10% of energy costs. Planning reserves costs may be covered by energy and operating reserve payments, or they may require additional payments, which would also be subject to reduction through use of RTP. RTP is likely to reduce these costs by a significant amount, but much of these costs will remain for a long time. Nonetheless, the benefits from RTP are likely to be underestimated from the simulations presented, because they do not incorporate the benefits from reduced need for reserves.

Closely related to reserves costs are the effect of non-convexities in operation of plants and lumpiness in the size of plants. As discussed in detail by Mansur (2003), generation units do not costlessly or instantly switch from off to full production. There are start-up costs and "ramping" constraints (on the speed with which output can be adjusted). These constraints make it more costly to adjust supply to meet demand fluctuations. As with reserves, RTP would allow some of this adjustment to occur on the demand side in a way that would enhance efficiency. Similarly, I have assumed the plants can be scaled to any size at the same long-run average cost. If this were not the case, then there would be greater mismatches between demand and the capital stock. In conventional electricity systems, these mismatches have been handled by over-building and then either selling excess production on the wholesale market or leaving excess capacity idle. Having the additional option of demand-side adjustment could only lower long-run costs.

The simulations also have ignored market power issues, instead assuming that free entry would bring a completely competitive market over the longer run. As has been discussed elsewhere,[15] demand elasticity introduced by implementing RTP reduces the incentive of sellers to exercise market power. However, it is unclear how much incremental inefficiency the exercise of market power itself introduces in a flat-rate system, since it simply changes the flat retail rate that is charged in all time periods. In fact, the BH

[15] See Borenstein and Bushnell (1999) and Bushnell (forthcoming).

analysis suggests that with all customers on flat rates, if the equilibrium flat rate is less than the second-best optimal flat rate, seller market power could increase efficiency. In a full RTP system, market power could not reduce deadweight loss. Thus, it is difficult to analyze the bias from excluding seller market power.

The demand system I've analyzed departs from reality by assuming all cross-elasticities are zero. Simulation with a complete matrix of own- and cross-elasticities would increase the complexity substantially. Still, if demands are generally substitutes across hour, it seems very likely that incorporation of cross-elasticities would increase the gains from RTP. Essentially, RTP increases efficiency by reducing the volatility of quantity consumed and increasing the utilization rate of installed capacity. Holding constant own-price elasticities, increasing cross-price elasticities from zero to positive (substitutes) will tend to further reduce quantity volatility by increasing off-peak quantity when peak prices rise and reducing peak quantity when off-peak prices fall.

Another simplification on the demand side is my assumption that the distribution of demand I've used comes from all customers being on flat rates. In fact, most large customers pay "time of use" rates, which have 2 or 3 tariff periods per week – peak during weekday work hours, shoulder during mornings and late afternoons/evenings, and off-peak at night and on weekends. The existence of these rates captures some of the benefits of RTP, but probably a very small proportion. Borenstein (forthcoming) estimates that TOU rates capture less than 15% of the real-time wholesale electricity price variation. Thus, while recognizing the existence of TOU rates prior to RTP will reduce estimates of the marginal gain from RTP, the change is not likely to be large.

Finally, the simulations take a constant $40/MWh charge for transmission and distribution. This is based on the historical recovery of the costs of these services, which are provided by a regulated monopoly. To the extent that minimum efficient capacity scale for T&D implies that they are never capacity constrained, introducing time-varying prices of these services would not improve efficiency. That may be the case with most local distribution, but transmission lines frequently face capacity constraints. By ignoring these constraints and holding the T&D cost per MWh constant, the simulations understate the potential gains for RTP that could also reflect time-varying (opportunity) cost of transmission.

V. Conclusions

Real-time electricity pricing has tremendous appeal to economists on a theoretical level, because it has the potential to improve welfare by giving customers efficient consumption incentives. The theoretical analysis, however, does not indicate how large the gains from RTP are likely to be. With a simple simulation exercise, I have tried to generate some numbers to go with the theory. This is obviously just a first cut, but the results suggest a number of likely findings:

– The efficiency gains of RTP for the largest customers are likely to far outweigh the costs.

– The incremental benefits of putting more customers on RTP are likely to decline as the share of demand on RTP grows. At the same time, the costs of increasing the share of demand on RTP may increase as the size of each customer declines. Thus, while there seems to be clear net social value from putting larger customers on RTP, the additional gains from putting smaller customers on RTP may not justify the cost. Further analysis of both the costs and benefits is needed.

– Large customers vary widely in the time patterns of their consumption. As a result, a move to end the current cross-subsidies by implementing RTP will cause large wealth transfers among these customers. The magnitudes of these transfers could be larger than the net efficiency gains.

Nonetheless, the findings of this study must be viewed as preliminary. As stated in the previous section, a number of factors have not been addressed in the analysis thus far. The tools for that analysis, however, are not particularly complex. A larger barrier may be the data necessary to permit accurate estimates of demand elasticities and supply flexibility.

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TABLE 2 -- Capacity, Price and Quantity Effects of RTP

A	B	C	D	E	F	G	H	I	J	K	L	M
Elas-	Share on	Total Annual	Total Annual	Flat	EQUILIBRIUM CAPACITY (MW)				PRICE DURATION CURVE			
ticity	RTP	Energy	Energy	Rate	Base-	Mid-		Total	Peak	Hours	Pctg	Pctg
		Consumed	Bill	($/MWh)	Load	Merit	Peaker		Price	per year	of annual	of annual
		(MWh)	($)						($/MWh)	at Peak	bill from	bill from
All On Flat Rate										Quantity	top hour	top 10
---	0	236,796,579	9,265,381,746	79.13	27491	5472	12912	45875		(of 8760)		hours
Some On RTP												
-0.025	0.333	237,100,299	9,153,056,157	79.08	27538	5414	10615	43567	55517	7	8.6%	11.8%
-0.025	0.666	237,370,671	9,067,201,748	78.91	27586	5336	8941	41863	22107	50	4.0%	9.8%
-0.025	0.999	237,596,395	9,005,973,722	78.72	27631	5257	7801	40689	9650	90	1.8%	6.5%
-0.050	0.333	237,395,027	9,076,176,975	78.94	27588	5337	9100	42025	26507	44	4.6%	10.3%
-0.050	0.666	237,861,897	8,966,267,596	78.62	27681	5186	7049	39916	6090	125	1.2%	4.9%
-0.050	0.999	238,258,096	8,888,326,800	78.44	27772	5034	5715	38521	2616	195	0.5%	2.8%
-0.100	0.333	237,969,466	8,982,619,333	78.68	27690	5185	7294	40169	8654	113	1.6%	5.8%
-0.100	0.666	238,809,721	8,840,599,109	78.35	27876	4891	4846	37613	1864	252	0.3%	2.1%
-0.100	0.999	239,517,938	8,731,658,462	78.17	28052	4612	3162	35826	940	382	0.2%	1.2%
-0.150	0.333	238,555,891	8,921,521,582	78.53	27796	5038	6134	38968	4494	335	0.8%	3.8%
-0.150	0.666	239,761,660	8,750,263,801	78.20	28071	4613	3335	36019	1071	734	0.2%	1.4%
-0.150	0.999	240,762,294	8,615,903,345	77.97	28331	4186	1454	33971	588	1141	0.1%	0.8%
-0.300	0.333	240,435,717	8,805,179,930	78.30	28124	4616	3897	36637	1843	312	0.3%	1.9%
-0.300	0.666	242,774,258	8,565,317,811	77.87	28664	3767	437	32868	510	702	0.1%	0.7%
-0.300	0.999	244,269,124	8,396,112,525	77.38	29157	1713	0	30870	297	1914	0.0%	0.4%
-0.500	0.333	243,251,232	8,719,880,253	78.12	28578	4045	2094	34717	1201	476	0.2%	1.3%
-0.500	0.666	246,834,756	8,440,185,760	77.37	29478	1353	0	30831	314	2023	0.0%	0.4%
-0.500	0.999	248,276,486	8,295,147,559	76.54	29488	0	0	29488	192	5697	0.0%	0.2%

TABLE 3 -- Welfare Effects of RTP

A	B	C	D	E	F	G	H	I	J
Elas-ticity	Share on RTP	Annual Total Surplus Change from All on Flat ($)	Annual TS Change as percentage of original energy bill	Annual CS Change of Customers on Flat Rate ($)	Annual CS change "per customer" on Flat Rate ($)	Annual CS Change of Customers on RTP ($)	Annual CS change "per customer" on RTP ($)	Annual Incremental Surplus to Switchers ($)	Annual Incremental Externality ($)
-0.025	0.333	102,678,220	1.1%	8,628,000	129	94,050,220	2,824	94,050,220	8,628,000
-0.025	0.666	180,133,021	1.9%	17,714,328	530	162,418,693	2,439	76,901,814	552,987
-0.025	0.999	233,726,979	2.5%	97,141	971	233,629,838	2,339	60,215,322	-6,621,364
-0.050	0.333	174,098,524	1.9%	29,852,468	448	144,246,056	4,332	144,246,056	29,852,468
-0.050	0.666	270,435,206	2.9%	40,393,439	1,209	230,041,767	3,454	100,117,028	-3,780,346
-0.050	0.999	335,855,459	3.6%	163,059	1,631	335,692,400	3,360	71,624,966	-6,204,713
-0.100	0.333	262,356,807	2.8%	71,409,037	1,071	190,947,770	5,734	190,947,770	71,409,037
-0.100	0.666	383,058,841	4.1%	61,428,039	1,839	321,630,802	4,829	125,164,413	-4,462,379
-0.100	0.999	472,596,878	5.1%	228,452	2,285	472,368,426	4,728	96,212,019	-6,673,982
-0.150	0.333	322,257,350	3.5%	95,049,750	1,425	227,207,599	6,823	227,207,599	95,049,750
-0.150	0.666	467,022,466	5.0%	73,932,013	2,214	393,090,453	5,902	149,091,603	-4,326,486
-0.150	0.999	578,021,567	6.2%	274,574	2,746	577,746,993	5,783	118,871,671	-7,872,570
-0.300	0.333	450,098,624	4.9%	131,733,121	1,975	318,365,503	9,561	318,365,503	131,733,121
-0.300	0.666	659,443,204	7.1%	99,888,884	2,991	559,554,320	8,402	214,009,350	-4,664,770
-0.300	0.999	815,479,611	8.8%	415,158	4,152	815,064,452	8,159	172,098,335	-16,061,929
-0.500	0.333	576,256,903	6.2%	159,412,061	2,390	416,844,842	12,518	416,844,842	159,412,061
-0.500	0.666	848,963,827	9.2%	140,337,732	4,202	708,626,095	10,640	274,726,516	-2,019,592
-0.500	0.999	1,023,011,668	11.0%	619,521	6,195	1,022,392,146	10,234	200,879,823	-26,831,983

Table 4 - Larger elasticity with higher demand

A	B	C	D	E	F	G	H	I	J	K	L	M
Elas-ticity	Share on RTP	Total Surplus Change from All on Flat	CS Change of Customers on Flat Rate	CS Change of Customers on RTP	Total Energy Consumed (MWh)	Total Energy Bill ($)	TS Chg as pctg of orig energy bill	Flat Rate ($/MWh)	CAPACITY Base-Load	Mid-Merit	Peaker	Total
All On Flat Rate												
---	0				236,796,579	9,265,381,746		79.13	27491	5472	12912	45875
Some On RTP												
-0.025	0.333	157,545,001	26,803,542	130,741,459	236,991,158	9,085,302,852	1.7%	78.96	27538	5408	9351	42297
-0.025	0.666	243,951,007	38,195,213	205,755,793	237,086,508	8,979,274,565	2.6%	78.65	27585	5319	7436	40340
-0.025	0.999	298,885,681	155,224	298,730,457	237,137,206	8,906,768,456	3.2%	78.47	27628	5239	6216	39083
-0.050	0.333	236,765,517	68,022,950	168,742,567	237,140,204	8,992,570,786	2.6%	78.70	27588	5323	7641	40552
-0.050	0.666	337,203,154	58,369,371	278,833,783	237,260,059	8,858,589,473	3.6%	78.39	27678	5165	5412	38255
-0.050	0.999	408,983,919	216,469	408,767,450	237,308,676	8,757,423,227	4.4%	78.22	27765	5008	3910	36683
-0.100	0.333	326,044,738	105,616,839	220,427,899	237,431,195	8,882,805,849	3.5%	78.46	27690	5171	5734	38595
-0.100	0.666	458,725,951	79,331,270	379,394,682	237,589,280	8,696,884,301	5.0%	78.13	27869	4862	2995	35726
-0.100	0.999	556,599,878	292,439	556,307,439	237,618,481	8,553,258,009	6.0%	77.90	28037	4556	1212	33805
-0.150	0.333	388,550,908	125,973,521	262,577,387	237,743,001	8,807,246,078	4.2%	78.33	27795	5019	4492	37306
-0.150	0.666	548,259,965	93,759,315	454,500,650	237,949,104	8,579,102,697	5.9%	77.95	28061	4566	1424	34051
-0.150	0.999	654,105,256	328,044	653,777,212	237,980,912	8,409,878,956	7.1%	77.75	28545	3370	0	31915
-0.300	0.333	520,163,226	160,199,235	359,963,991	238,848,369	8,659,461,195	5.6%	78.12	28119	4589	2164	34872
-0.300	0.666	738,000,654	133,403,922	604,596,733	239,143,520	8,357,852,123	8.0%	77.45	28645	2660	0	31305
-0.300	0.999	876,948,576	526,873	876,421,703	238,916,109	8,168,930,017	9.5%	76.91	29104	554	0	29658
-0.500	0.333	642,921,839	182,922,073	459,999,766	240,699,954	8,548,413,692	6.9%	77.98	28563	4007	412	32982
-0.500	0.666	897,815,233	173,817,360	723,997,873	241,140,515	8,216,688,638	9.7%	76.95	29438	273	0	29711
-0.500	0.999	1,037,933,082	718,386	1,037,214,695	240,578,837	8,076,751,463	11.2%	76.13	28821	0	0	28821

Table 5 - Smaller elasticity with higher demand

A	B	C	D	E	F	G	H	I	J	K	L	M
Elas-ticity	Share on RTP	Total Surplus Change from All on Flat	CS Change of Customers on Flat Rate	CS Change of Customers on RTP	Total Energy Consumed (MWh)	Total Energy Bill ($)	TS Chg as pctg of orig energy bill	Flat Rate ($/MWh)	CAPACITY Base-Load	Mid-Merit	Peaker	Total
All On Flat Rate												
---	0				236,796,579	9,265,381,746		79.13	27491	5472	12912	45875
Some On RTP												
-0.025	0.333	58,727,219	1,205,436	57,521,783	237,158,529	9,207,151,302	0.6%	79.12	27538	5430	11628	44596
-0.025	0.666	112,243,574	4,681,866	107,561,708	237,517,065	9,153,369,753	1.2%	79.07	27587	5351	10530	43468
-0.025	0.999	158,505,193	30,698	158,474,495	237,861,246	9,106,792,650	1.7%	79.00	27633	5271	9586	42490
-0.050	0.333	109,341,391	8,149,477	101,191,913	237,525,042	9,157,009,222	1.2%	79.08	27587	5339	10620	43546
-0.050	0.666	194,498,884	16,280,209	178,218,675	238,215,807	9,072,908,910	2.1%	78.92	27682	5205	8865	41752
-0.050	0.999	257,799,499	91,796	257,707,702	238,844,099	9,009,698,122	2.8%	78.74	27775	5060	7613	40448
-0.100	0.333	188,537,111	27,643,155	160,893,957	238,266,080	9,083,493,526	2.0%	78.95	27686	5204	9047	41937
-0.100	0.666	303,746,068	39,017,670	264,728,399	239,563,575	8,970,704,942	3.3%	78.64	27878	4918	6788	39584
-0.100	0.999	386,802,144	161,431	386,640,712	240,732,552	8,889,861,015	4.2%	78.45	28060	4648	5259	37967
-0.150	0.333	247,807,006	50,716,150	197,090,856	239,019,940	9,031,903,407	2.7%	78.81	27790	5053	7948	40791
-0.150	0.666	383,404,025	52,616,339	330,787,686	240,910,312	8,902,357,295	4.1%	78.47	28075	4647	5387	38109
-0.150	0.999	485,892,075	203,194	485,688,881	242,602,132	8,804,881,640	5.2%	78.27	28344	4240	3628	36212
-0.300	0.333	372,487,358	93,384,734	279,102,624	241,402,170	8,939,712,208	4.0%	78.54	28116	4640	5805	38561
-0.300	0.666	567,518,500	76,241,511	491,276,988	245,066,862	8,767,810,641	6.1%	78.17	28673	3826	2577	35076
-0.300	0.999	724,209,622	287,558	723,922,064	248,281,666	8,630,164,263	7.8%	77.92	29189	3037	342	32568
-0.500	0.333	496,384,422	123,476,114	372,908,308	244,863,984	8,877,187,599	5.4%	78.35	28569	4080	4024	36673
-0.500	0.666	764,639,032	97,476,438	667,162,594	251,011,575	8,666,362,101	8.3%	77.90	29486	2750	147	32383
-0.500	0.999	968,953,455	448,853	968,504,602	255,110,014	8,517,019,030	10.5%	77.25	30260	0	0	30260

Table 6 - RTP effect when RTP customers have flatter load profiles

A	B	C	D	E	F	G	H	I	J	K	L	M
Beta of load profile	Elas-ticity	Share on RTP	Total Surplus Change from All on Flat	CS Change of Customers on Flat Rate	CS Change of Customers on RTP	Total Energy Bill ($)	TS Chg as pctg of orig energy bill	Flat Rate ($/MWh)	CAPACITY Base-Load	Mid-Merit	Peaker	Total
All On Flat Rate												
	---	0				9,265,381,746		79.13	27491	5472	12912	45875
Some On RTP												
0.9	-0.025	0.333	99,624,994	-41,877,295	141,502,289	9,157,514,167	1.1%	79.40	27536	5431	10679	43646
0.9	-0.025	0.666	175,518,913	-81,808,506	257,327,419	9,072,162,747	1.9%	80.16	27582	5330	9059	41971
0.9	-0.100	0.333	257,140,670	20,587,059	236,553,611	8,988,385,082	2.8%	79.00	27682	5189	7420	40291
0.9	-0.100	0.666	377,208,465	-29,724,172	406,932,637	8,846,948,184	4.1%	79.51	27862	4895	4985	37742
0.9	-0.300	0.333	443,233,696	83,652,252	359,581,444	8,812,559,694	4.8%	78.60	28101	4620	4067	36788
0.9	-0.300	0.666	651,846,553	15,400,894	636,445,659	8,572,685,651	7.0%	78.94	28626	3772	611	33009
0.7	-0.025	0.333	92,443,625	-144,362,750	236,806,375	9,164,346,148	1.0%	80.04	27532	5415	10861	43808
0.7	-0.025	0.666	166,007,832	-282,042,240	448,050,072	9,082,605,729	1.8%	82.70	27575	5330	9292	42197
0.7	-0.100	0.333	245,621,529	-82,880,174	328,501,703	9,000,548,890	2.7%	79.65	27666	5185	7702	40553
0.7	-0.100	0.666	365,275,172	-213,509,726	578,784,897	8,859,907,722	3.9%	81.83	27834	4893	5283	38010
0.7	-0.300	0.333	428,566,321	-14,847,293	443,413,614	8,826,814,375	4.6%	79.22	28057	4620	4431	37108
0.7	-0.300	0.666	635,986,632	-155,533,857	791,520,489	8,587,822,539	6.9%	81.10	28548	3774	973	33295
0.5	-0.025	0.333	85,278,387	-246,893,494	332,171,881	9,172,160,211	0.9%	80.69	27529	5423	11021	43973
0.5	-0.025	0.666	154,535,809	-484,784,645	639,320,455	9,094,734,430	1.7%	85.27	27567	5343	9527	42437
0.5	-0.100	0.333	233,181,003	-188,833,909	422,014,911	9,013,795,042	2.5%	80.33	27650	5188	8001	40839
0.5	-0.100	0.666	353,012,405	-399,976,343	752,988,748	8,873,157,545	3.8%	84.20	27806	4893	5590	38289
0.5	-0.300	0.333	412,677,245	-116,253,995	528,931,239	8,842,817,968	4.5%	79.87	28010	4622	4825	37457
0.5	-0.300	0.666	620,963,420	-328,470,009	949,433,429	8,602,356,898	6.7%	83.32	28471	3764	1357	33592

FIGURE 1: Load Profile