Real Time Pricing in Electricity Markets

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Demand side response is increasingly being considered as necessary for the success of competition in the electricity sector. The gap between wholesale prices and capped retail prices in California is now recognized as one of the main flaws in that state's market design. In reaction, California started installing advanced meters to provide more real-time price signals to customers with larger than 200 kW of demand. Around the U.S. and the world there are other experiments. Yet, the evidence on customer interest in these programs is weak. More generally, retail choice does not seem to work well for residential and small commercial users. In addition to reluctance of these customers to switch from their time-tested local suppliers, costs associated with metering appear to be an impediment. State-mandated programs or those financed by state or quasi-state companies internalize these costs, but in open markets, retail electricity providers (REPs) need to evaluate the economics of these services on a customer-by-customer basis. A preliminary look at the less-than-1MW commercial customer market in Texas indicate that even those customers who are likely to save money if they were to settle under market-based pricing as opposed to the profile assigned to them by ERCOT may not be interested. The main reason appears to be that savings may not be high enough to compensate for the costs associated with advanced metering neither for the customer nor for the REPs.

INTRODUCTION

One of the primary reasons for the crisis in California was the gap between wholesale prices and retail prices that were capped. The inability to pass the increases in wholesale prices to end-users not only led to PG&E's bankruptcy but also prevented consumers from responding to price signals by lowering their consumption and pushed the system to its limits. Without demand-side response, electricity markets cannot be expected to function efficiently and market manipulation could become easier as the demand peaks and supplies tighten, which then jeopardizes the reliability of the system. Regulators seem to concur. In 1998, after the Midwest price spikes, FERC identified the lack of adjustment on the part of retail customers to prices as a contributing factor. In 2000, FERC issued its order accepting the market revisions in New England, and again acknowledged that "the lack of price-responsive demand is a major impediment to the competitive electricity markets."[1]

Braithwait & Faruqui (2001) carried out a simulation analysis of California data to show that, under a medium demand-response scenario, a mere 2.5% decrease in load during peak times could have lowered prices by about 24%. In addition, this reduction in load could help avoid most (if not all) of blackouts and brownouts.[2] The latter observation shows how important it is for consumers to receive the correct price signals from the perspective of system reliability. In 2000, the NERC acknowledged this point when it noted that to "...improve the reliability of electric supply, some or all electric customers will have to be exposed to market prices."[3] Clearly, for system reliability, a reduction in demand is an almost perfect substitute to building new generation and/or transmission capacity.

Bushnell and Mansur (2001) have shown that the average electricity consumption in San Diego decreased by roughly 6% in August 2000 (and similarly in September) and that the most of the reduction (9%) occurred between 4-7 pm (peak hours). Authors suggest that because of the uncertainty about the duration and the credibility of the rate increase, these results should be viewed as a lower bound on the demand reductions that could be achieved through pricing incentives. But, after the California State Legislature passed an amendment to refund the difference and re-establish a retail price cap in September 2000, demand rebounded in San

Diego. Interestingly, these results were achieved without market-based pricing approaches. Instead, customers waited weeks to see the impact of higher prices on their bills.

Could bigger savings be achieved by consumers if market-based pricing approaches such as real time pricing (RTP) or time-of-use (TOU) pricing were being implemented? Could these methods help avoid brownouts and/or blackouts? Many people think so. According to Colledge, et al. (2002), experiments with market-based pricing in Texas led to a shift or curtailment of almost a third of demand from peak to off-peak periods. California already have real time meters for about 8,000 MW of load (rendered useless during the crisis due to the rate freeze) and is installing more (the proposal before Summer 2001 was to get all customers above 200 kW demand on RTP at an estimated cost of $30 million). Enel, in Italy, is setting up 27 million residential customers with advanced meters and associated communications devices. In addition to these somewhat government-mandated programs, there are also private sector efforts in the U.S. Puget Sound, Georgia Power, Florida Power & Light are among the leaders in experimenting with these programs.

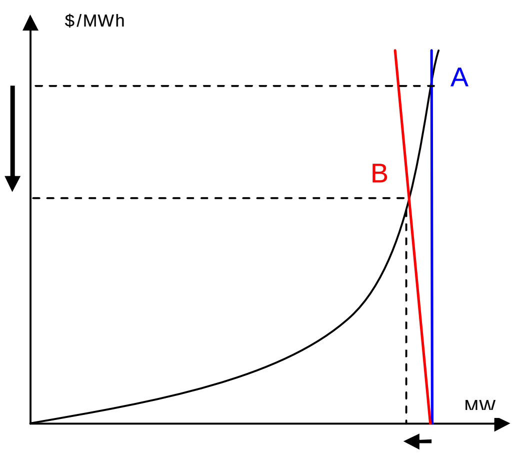
Despite the economic justification, however, competitive suppliers in restructured markets (and even regulated utilities) are reluctant to move forward with market-based pricing. Costs seem to be prohibitive, especially for smaller customers (although the threshold for small is dynamic as market conditions and technology change). In addition, there are concerns about customers' interest in these programs (and in switching suppliers in general). Finally, the past experience with these pricing schemes, especially under the DSM programs, is not encouraging even for larger commercial and industrial customers. These are the issues that we will analyze in this paper to see whether the current competitive market conditions and technological innovations are likely to overcome these barriers and to encourage the use of market-based pricing approaches. An example from the recently opened Texas retail markets, however, provides support to the concerns mentioned in this paragraph.

ECONOMICS OF DEMAND RESPONSE

Per their nature, all energy commodity prices are volatile, but the analysis of the historical data shows that they follow a fairly normal distribution and they revert to the mean (although the mean may change in the medium to longer term because of fundamental changes in demand, supply or both). Mean reversion is important because it implies that extremely high or extremely low prices are short-term abnormalities that will be eliminated when demand and/or supply respond to these price signals. This is the case for even the price of crude oil, which is influenced by OPEC, as well as for the natural gas price in the U.S. One would expect the same distributional characteristics to manifest themselves for other commoditized energy market including the one for electricity. The necessary condition, however, is to allow the fluctuations in the wholesale market to be passed on to the retail market to ensure demand response.

Chart 1 compares the situation where this link is not established and hence the demand is not responsive to price (vertical demand curve in blue) to the case where this link is established (at least partially) and the demand has an elasticity that is greater than zero (red). Hirst (2001) uses a similar chart to represent generator offers to the CalPX in June 2000. Point A represents basically what happened in California without demand response and yielded a price of $550/MWh for roughly 29 GWs of demand. However, using an elasticity of 0.1 (still very inelastic demand), point B could be reached where the price is $250/MWh for roughly 27.5 GWs of demand. This elasticity was analogous to the PJM's study of its market conditions on June 7, 1999. The ISO calculated that a 4% drop in demand could have lowered the price by almost 50% on that day. Similarly, based on data from the US and the UK, Braithwait & Faruqui (2001) calculated load-weighted elasticities ranging from 0.07 to 0.135. Note that these elasticity estimates are based on data from markets where only some of the larger

Chart 1 – Electricity Supply & Demand



customers are able to respond to market-based prices. It is possible to have more elastic aggregate demand if more users (possibly from all market segments) are enabled to respond to real-time prices.

MARKET-BASED PRICING METHODS

Real Time Pricing (RTP)

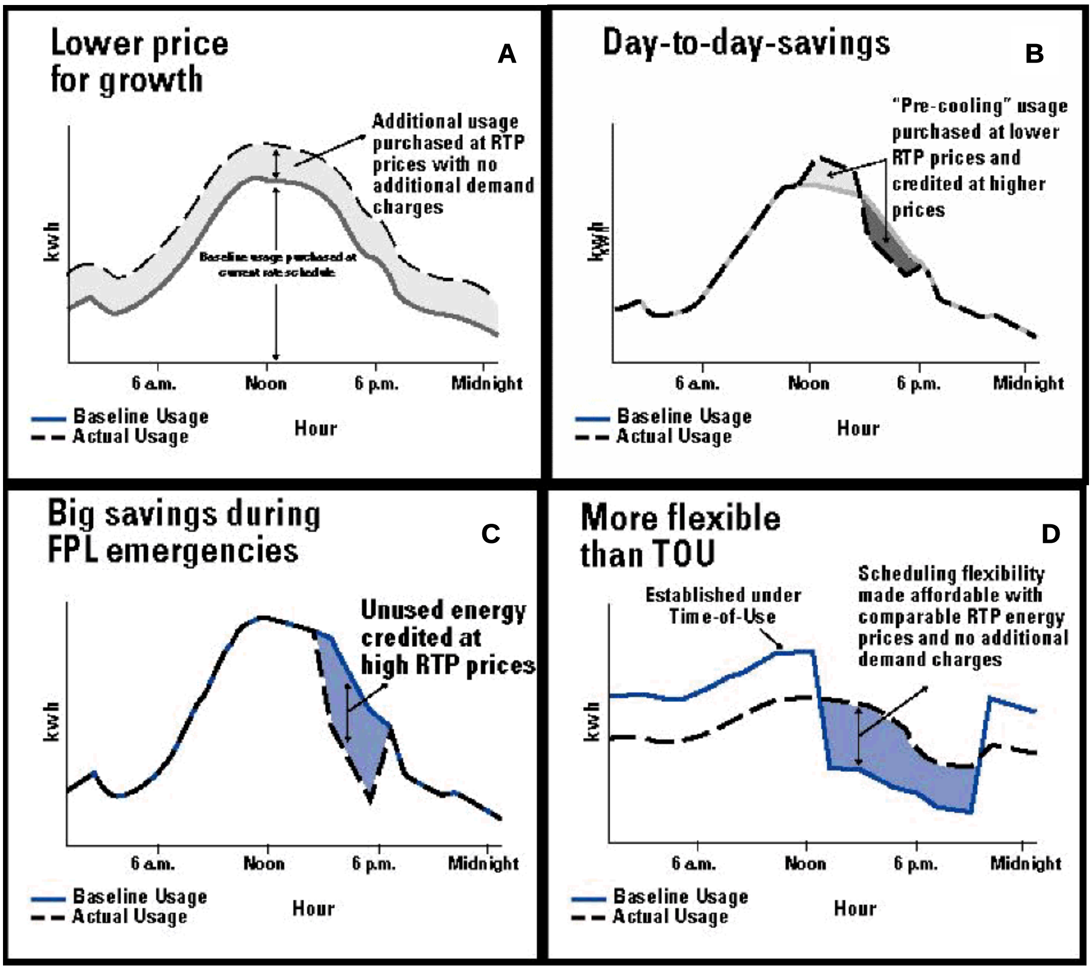
As demand fluctuates during the day, different type of power plants with different cost structures are brought on and off line as needed. This leads to fluctuations in the marginal cost of generation. Real time rates vary in higher frequency (15-minute to an hour) in order to reflect these fluctuations more accurately and hence to increase the economic efficiency by providing customers better price signals.

As one approach, the actual billing history of customers is used to create a baseline usage – amount paid on non-RTP rates for that historical usage. If demand in any period is higher than the baseline, the customer pays the RTP price. If demand is lower than the baseline, the customer receives a credit for load reduction at the RTP price (see **Charts 2A** and **2B**). As a result, in period t, the customer is charged according to the following equation:

$$P_{MC}(t) * [D_{ACT}(t) - D_{BL}(t)] \qquad (1)$$

where: $P_{MC}(t)$ is the marginal price; $D_{ACT}(t)$ is the actual electricity demand; and $D_{BL}(t)$ is the baseline usage in period t.

Charts 2A-D – Florida Power & Light RTP Program



Source: http://www.fpl.com/savings/efficiency/contents/real-time_pricing_program_rtp.shtml#P24_325

The total bill (monthly, weekly, etc.) is calculated as the sum of all period charges within the bill period. Clearly, customers who can lower their consumption during peak hours below their baseline will benefit greatly from this arrangement. In **Chart 2C**, one can see the large potential savings that customers may realize if able to switch and/or curtail load during emergencies in the FPL service territory. If, for any reasons, a customer is not able to deviate much from his/her baseline, there will be no significant (if any) difference in his/her bill. Finally, **Chart 2D** makes the point that RTP is more flexible than TOU, allowing utilities to manage peak-time emergencies more efficiently (at least from the perspective of FPL's experience).

RTP can also be used together with interruptible loads. Utilities have been offering interruptible contracts for a while now to mostly large users, who benefited from the lower rates. The risk of interruption by the utility has usually been very low. Combined with RTP, a customer accepts an interruptible load schedule instead of his/her baseline for certain periods and benefits when it reduces its load below the interruptible level. If the customer fails to reduce its load, it pays the marginal price times the difference between the actual and the interruptible level in addition to possible penalties. Then, equation (1) becomes:

$$P_{MC}(t_I) * [D_{ACT}(t_I) - D_I(t_I)] \qquad (2)$$

where: $D_I(t_I)$ is the subscribed interruptible level in period t_I.

Time of Use (TOU) Pricing

Although TOU rates are not set for as high frequency as RTP rates, they are also designed to reflect the fluctuations in marginal cost of generation during the day as the system load changes and different plants operate at different times. But, the TOU approach usually divides the day into several time blocks (usually two to five) and predetermines the rates for each block. As such, these rates cannot be as accurate as RTP rates in reflecting the marginal cost of generation. Nevertheless, they have some flexibility in distinguishing among different customer types. While residential and small commercial users may prefer a simpler rate structure, large commercial and industrial customers often prefer a more complex tariff structure, especially if they can see the savings.

TOU rates have to be provided for at least two time blocks to emphasize the difference between on-peak and off-peak hours. Further divisions as mentioned before are possible. In addition, the on-peak and off-peak rates may vary across days and/or across seasons. Rates are set ahead of time for a certain period (usually several months), which allows customers to get ready for switching and/or curtailing their load from on-peak to off-peak periods.[4] But, in order to design TOU rates, utilities and competitive suppliers have to determine their costs and convert their costing periods into rating periods. These two need not overlap, because on-peak periods, which are expensive for the users, may be too long to allow them the opportunity to switch/curtail load and/or there may be too many costing periods for the user to remember.

EXPERIMENTS

Puget Sound Energy, Bellevue, Washington[5]

Puget Sound Energy (PSE) is the first electric utility to invest in real-time meters for all customer classes and the first electric distribution utility in the nation to provide TOU price and comparative TOU consumption information to all classes of customers. PSE subsidiary ConneXt developed the software that automates the meter reading process, which allows the company to match hour-by-hour energy usage with real-time energy-market pricing. Customers can plan and check their energy usage on PSE's web site, using the Personal Energy Management™ system. A pricing trial of this system is expected to continue through May 2002.

Since May 2001, about 300,000 PSE customers have been paying variable TOU rates for electricity. The customers pay about 30% less during off-peak hours than at high-demand times of day. Power-usage data from June and July indicate that TOU rates are promoting a strong conservation ethic among PSE customers. Customers paying these rates shifted about 5% of their load, on average, from the morning and early evening hours when public demand for power - and wholesale power prices - are highest. That 5% shift is in comparison to the peak-period power use of PSE customers who already are receiving detailed personal reports on the timing of their electricity consumption, but not TOU rates. In addition, customers paying TOU rates reduced their overall electricity usage in June 2001 by more than 6% compared to their June 2000 usage. In a July 2001 survey of 821 PSE customers paying TOU rates, 89% said the program has spurred them to shift some load to off-peak hours. 49% said they have cut their overall consumption. Nine in 10 said they would recommend the TOU program to a friend.

Georgia Power, Atlanta, Georgia[6]

Georgia Power has different TOU options. One option (TOU-4) for large users (>1,000 kW) has a monthly base rate of $475 and different rates between noon and 8 pm during weekdays for different loads. The prices also differ between June-September and October-May periods. The company also has TOU options for smaller commercial and industrial users as well as residential users. Residential model (TOU-REO-1) has a $10 monthly charge. Between June and September, on-peak kWh costs $0.1749 and off-peak kWh costs $0.05403. Between October and May, first 650 kWh is priced at $0.05403 and everything above is priced at $0.0302 per kWh.

Georgia Power also has RTP options that are based on the baseline usage methodology described above. One option (RTP-DA-1R) is available to all customers who are able to benefit from hourly price signals and can demonstrate and maintain a peak 30-minute demand no less than 250 kW. Hourly prices are determined each day based on projections of hourly running cost of incremental generation, transmission and outage costs, etc. An administrative charge of $155 or $250 for customers with loads larger than 1,000 kW and $175 and $270 for smaller customers will be applied. Those who pay the larger sum receive a computer, a printer and a modem. Those who pay the lower sum must provide this equipment in compliance with the company's specifications. There are also other RTP options (RTP-HA-1R, RTP-DAA-1, RTP-HAA-1) for larger users. Other TOU options include TOU-EO-1, TOU-GSD-1, TOU-SSD-1 and TOU-MAM-1.

Georgia Power lets large energy consumers track prices and cut use based on price. With the use of the Internet to inform 1,650 of its biggest business customers of price fluctuations, Georgia Power can save as much as 800 megawatts at a time (enough to power almost 225,000 homes). At certain days, customers reduced load by 30% during periods of $300/MWh power and by 60% during periods of $1,000/MWh power.

Florida Power and Light[7]

Florida Power and Light proposes a particular RTP metering system that can benefit small companies whose current TOU rate is too restrictive or who own energy management systems. Businesses who qualify for their proposed system have to be currently in rate classes GSLD-2, GSLDT-2, GSLD-3 and GSLDT-3 or GSLD-1, GSLDT-1 with demands greater than 1,000 kilowatts. The benefits to RTP are lower average pricing, no demand charges for incremental usage and hourly price variations (see **Charts 2A-2D**).

Metering Use in the UK[8]

The electricity market uses 30 minute intervals to log consumption in order to build up a profile of electricity use over 24-hour periods, and until recently, customers wishing to take advantage of the competitive market were obliged to have a special meter installed which recorded the consumption every 30 minutes.

A trading system, which opens up the market to all customers including the residential sector has been geographically phased in since September 1998. Because half hourly metering may be too expensive for the majority of customers in this market opening, an alternative has been introduced which requires no change to the existing meter or the frequency of meter reading, but is based on assigning a 24 hour profile to the customer. The eight profiles assigned (two for residential and six for commercial & industrial users) are based on historic records from sample surveys conducted over many years, and are expressed as a series of 48 regression coefficients, and accounts for factors such as temperature, lighting up time and the type of day (e.g. Sunday, Bank Holiday, etc.). As we will see, ERCOT in Texas followed a similar approach to develop three profiles for small commercial users (<1 MW) but not for residential users.

These profiles were found inadequate to represent the variety among the customers, but there are strict requirements for the introduction of new profiles:

? That the profiles can be allocated easily and unambiguously to each metering system in an auditable way;

? That profiles should be derived from and maintained through load research;

? That each profile is statistically different from any others that are in use;

? That each profile should be designed to reproduce average half hourly demand as accurately as practical within the class it represents;

? That, if a large number of customers move to the new profile, then remaining profiles are still coherent and robust;

As a result of these requirements, many considered market-based pricing alternatives. Half hourly metering is considered an accurate but expensive solution, whereas profiling is low cost but potentially inaccurate, especially for residential users. In particular, the profiles make it difficult for an electricity supplier to calculate the profitability of all but the simplest tariff. One of the compromise solutions, *Reduced Data Profile Representation*, can be applied to reduce data volumes for each customer through regression modeling in the meter and occasional transmission of the reduced data set to the settlement agency, resulting in lower collecting and processing costs than half hourly metering and more accuracy than straight profiles.

An alternative is *Virtual Metering*, which models the consumption of the customer either within IT systems operated by the electricity supplier or within the Settlement system. The control algorithm would be simulated; identical or near identical parameters would be input along with any available total consumption data and associated profiles. This will result in a stream of half hourly data, which accurately reflects the consumption that can be input into the Settlement system with more confidence than straight profiles.

As can be seen, after more than ten years of a competitive electricity market with the highest rate of switching among residential customers, there are concerns about this segment of the market even in the UK.

CHALLENGES

Costs Associated with Advanced Metering

Clearly, the utilities as well as competitive suppliers that are willing to provide these services will also have to upgrade their own information systems to manage the significantly increased data flow from their customers. Colledge, et al. (2002) estimate the cost of replacing or upgrading these systems in the range of $50 to $100 million for a midsize or large utility. While the regulated utilities may be concerned about regulatory approval of costs, competitive suppliers are more concerned about being able to recover these upfront costs.

Customers, on the other hand, will be expected to cover the costs of the installation and O&M costs associated with the advanced meters (interval data recorders – IDRs). One-time costs (meter + installation) associated with an IDR meter can range from $450 to $1,500 (the low end is based on IDR meters that can be acquired for about $200 per equipment in large quantities). Monthly fees for small users (<1 MW) range from $10 to $300.[9] Even relatively cheaper TOU meters ($80-$200 with similar monthly fees) can be too costly for small users. A third and more recent alternative is to use the power lines to transport consumer data. Although this is a fairly untested technology especially in terms of data-carrying capacity of these wires, Colledge, et al. (2002) estimate an investment of $160-170 per household with similar monthly fees.

Lack of Customer Interest

Except for the UK and, perhaps to a certain extent, PJM markets, smaller customers have not been switching their electricity suppliers. And, even in these markets, switching rates are ranging from only 20% to 40% depending on the customer type and there are doubts about the future health of switching.[10] California experiment with retail switching was declared a failure early on with Enron abandoning the market after losing upwards of $30 million in marketing. The program is officially suspended after the crisis in California. In Texas as well, residential and most small commercial customers are not signing up with new suppliers although it is still early in the Texas 'experiment with competitive electricity markets and people may be more cautious after California and Enron debacles.

As market-based pricing and associated metering and energy services could be important for retail providers to compete, the reluctance to switch is concerning. Goett, et al. (2000) report the results of a retail choice experiment. One of the factors they used to measure the customer interest was the market-based pricing alternatives. The results are not encouraging: the small/medium commercial and industrial customers had an overall negative reaction to market-based rate structures. Hourly rates were considered worse than TOU rates, which were considered worse than seasonal rates. Overall, customers seemed to prefer fixed rates. Note that they focused on commercial and industrial users; it is highly likely that they would get similar negative reaction from residential users as well.

Doubts about Past Experiments

Some of these pricing methods were implemented under the DSM programs. In particular, there have been many studies that concluded there was little response from the businesses to TOU rates.[11] Note, however, that most studies are from the 1980s and hence do not reflect the competitive market conditions and the price volatility that comes with restructuring nor the advances in metering and computer technologies.

At the same time, Tishler (1998) shows the potential value of even simple (two-period) TOU pricing by allowing for labor separability (i.e., the ability to switch labor and hence some production from on-peak to off-peak hours) based on an experiment in Israel. Unlike the previous studies, this assumption yielded a higher price elasticity and hence a greater response to TOU pricing. Nevertheless, the majority of evidence (statistical and/or anectodal) does not give confidence for the future success of market-based pricing approaches, especially for smaller users.

THE TEXAS CASE: ERCOT PROFILES VS. MARKET-BASED PRICING[12]

In Texas 'restructured electricity market, users with peak demand larger than 1 MW are required to have IDR meters and settle based on the reading of these meters. On the other hand, small commercial customers (<1 MW), which consume 75% of total commercial sector electricity use, are assigned one of the three load profiles: low load factor (LLF), medium load factor (MLF) and high load factor (HLF), depending on the customer's historical usage.[13]

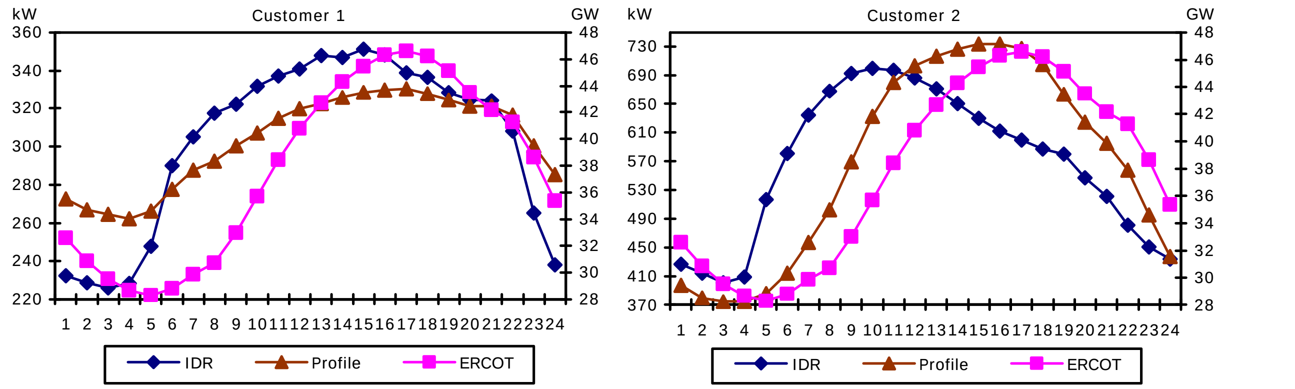
Adding the residential customers to the mix, a significant portion of the load in Texas will remain non-responsive to real-time fluctuations in the electricity price. For the next few years, Texas is expected to have a comfortable reserve margin and with larger users already settling based on IDR reads, price volatility may not be a serious problem. Although prices are said to reach regularly the $1,000 cap in the balancing market since the market opened on January 1, 2002, many attribute these spikes to the adjustment period to the new market rules that market players are going through. In fact, there are recent reports that the balancing market is becoming more stable, partially thanks to the monitoring efforts of ERCOT and the PUC.

Nevertheless, similar to what we have seen in **Charts 2A-2D**, it is very likely that profiles assigned by ERCOT to small commercial users will differ from their actual usage patterns as they would be determined based on IDRs. In particular, some would face lower costs under an IDR-based system than the profile-based settlement; and others would face lower costs based on the ERCOT profile. Clearly, the former group would be interested in IDR services if they were aware of this difference and if it were high enough to cover the costs.

Retail Electricity Providers (REPs) would also be interested in this group because their actual usage will mostly be cheaper to serve with less need for spot transactions (for energy and/or ancillary services) during peak times. The benefits from serving this group of customers can be further enhanced if they also have some curtailment and/or switching ability. This ability could lower spot costs (if any). So, the difference between the profile and the IDR costs can be split between the customer and the REP. *But, the decision depends on the condition that this difference is large enough to compensate for costs associated with installation and servicing of IDR meters*.

In **Chart 3**, we compare two different customers (both with <1 MW peak demand) in an average July day in Texas. Customer 1 is assigned an HLF profile and Customer 2 is assigned an MLF profile by ERCOT based on their historical usage and according to the formula provided in endnote 13. Brown lines represent these profiles while the blue lines represent IDR reads. Pink lines represent the actual ERCOT system load in an average July day.

Chart 3 – Comparison of ERCOT Profile and IDR-implied Actual Use



Clearly, Customer 1 would prefer to settle under the profile rather than the IDR reads as the former implies a usage below the latter during the system peak hours (roughly between 13:00-20:00). Customer 2, on the other hand, would rather settle based on the IDR reads as these imply a significantly lower consumption than the profile during the system peak hours. Then, the question is whether Customer 2 would save enough to justify the costs associated with IDR metering.

We carried out a simple exercise to compare the costs of serving these two customers from the ERCOT system under the profile and the IDR. We used the following estimates of the ERCOT system marginal cost ($/MWh).

Load (GW)	Natural Gas Price ($/MMBtu) 1.50	3.50
<22	10.00	10.00
22-36	10.50	24.50
36-52	16.50	38.50

These values are based on the following observations about the ERCOT system: When the load is less than 22 GW (only during shoulder months during 1-5 am), nuclear, coal and lignite plants meet most of the requirements. Between 22 and 36 GW, most efficient gas-fired combined cycle and cogeneration facilities are called upon (average heat rate of 7,000). After 36 GW (May through September, most of the day), less efficient gas-fired steam and simple cycle plants are needed with heat rates increasing from 9,000 to 11,000 and upwards; for simplicity we picked an average heat rate of 11,000. In 1999, the actual ERCOT system load peak in August stayed below 52 GW, which we have taken as the end of our range.

Then, we calculated a typical day for each month where each hour's consumption was calculated as the average across the whole month for both the profile and the IDR. Then, we calculated the cost difference between the two across 24 hours of the typical day based on the actual ERCOT system load (1999) for each hour and the corresponding system marginal cost from the table above. Monthly averages were then aggregated by multiplying this daily value with the number of days in each month. Finally, the total annual cost difference was calculated as the simple sum of monthly values.

Based on these calculations, Customer 2 could save roughly between $575 ($1.50/MMBtu gas) and $1,100 ($3.50/MMBtu gas) in a year if it were settled based on the IDR reads instead of the ERCOT profile. Customer 1, on the other hand, could save between $124 and $376 under the ERCOT profile. These numbers confirm the expectations based on the visual observation of **Chart 3**.[14]

Given that one-time costs for IDR meters range from $450 to $1,500 and that monthly fees range from $10 to $300, the decision is not straightforward. Although, annual savings of $575-1,100 are probably large enough to cover monthly fees, depending on the number and type of meters needed to provide market-based pricing, upfront costs can deter investment both on the part of Customer 2 and on the part of the REP. There is always the possibility that these savings will not be considered by Customer 2 significant enough to even bother with inquiring about IDRs and RTP services, or that the REP may consider to serve this customer too costly.

Also, note that Customer 2 is a fairly large user within the less-than-1MW category, with its July average peak near 750 kW and its overall peak actually near 1 MW (not shown in chart). If such large users are not likely to gain from these services, smaller users will probably be less interested.

CONCLUSIONS

Despite the economic justification of market-based pricing approaches such as RTP and/or TOU, there does not seem to be sufficient market incentives for smaller customers and retail service providers to implement them. Although the threshold for defining the "small" customers is dynamic as market conditions and technology change, upfront costs seem to be prohibitive for residential and most commercial customers. The Texas case study indicates that customers with <1 MW peak demand (greater loads are required to have IDRs for settlement purposes) are not very likely to be interested in market-based pricing. In addition, the smaller customers' interest in these programs and in switching suppliers in general has been fairly low where the market was open. Finally, the past experience with these pricing schemes, especially under the DSM programs, is not encouraging even for larger commercial and industrial customers.

Nevertheless, if the electricity markets continue to open up for competition, prices will become more volatile and customers may change their minds about these services in order to hedge their price risk. Improvements in metering technology would also encourage both customers and service providers to pursue RTP and/or TOU as costs will likely fall. Finally, concerns about system reliability may cause regulators and/or system operators to promote, if not require, these services to be offered by the service providers. But, even then, the threshold for what market segment (based on peak demand) should be required to have these services needs to be decided. As some of the studies sited indicate, all customers do not need to settle based on RTP in order to ensure system reliability. Developments in California, Texas, Italy and elsewhere indicate that this track will probably be seriously pursued.

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ENDNOTES

[1] For detailed discussion of these issues and references, see Hirst (2001).
[2] Also see Faruqui, et al. (2001).
[3] See Hirst (2001).
[4] Borenstein (2001) points out, however, that the infrequency of adjusting TOU rates creates an environment where wholesalers may exercise market power.
[5] For details, visit http://www.pse.com.
[6] For details, visit http://www.southerncompany.com/gapower.
[7] For details, visit http://www.fpl.com.
[8] For details, visit http://www.eatl.co.uk/products_services/en_trading/future.htm.
[9] Colledge, et al. (2002) estimate monthly fees at around $3-4 for residential users. Our research of the experiments around the country, however, indicates a lower bound of $10 for monthly fees.
[10] See discussion of the UK profiles above.
[11] See Aigner and Hirschberg (1985), Aigner, Newman and Tishler (1994), Park and Acton (1984), Schwarz (1984) and Woo (1985).
[12] Work in progress, please do not quote.
[13] See discussion of the UK profiles above. ERCOT uses the following formula to calculate load factors:

$$AvgLF ? \frac{\overset{12}{\underset{m?1}{?}} AHUse_m}{\overset{12}{\underset{m?1}{?}} MaxKW_m}$$

where $AHUse_m$ is the average hourly use and $MaxKW_m$ is the peak hourly demand for month m.
[14] Note that this exercise considers what it would cost to serve the customers' loads from the generation perspective and hence does not necessarily correspond to prices that could be charged to these customers under the Profile or IDR by the REPs. Naturally, the REPs' costs and profit margins should be incorporated into actual end-user prices. This may imply larger savings for the customers, depending on how much the REPs are able to save in their wholesale and spot purchases after IDR-based services start and how much they are willing to share with the customers.