

**SMART METERS, REAL TIME PRICING, AND DEMAND  
RESPONSE PROGRAMS:  
IMPLICATIONS FOR LOW INCOME ELECTRIC CUSTOMERS**

Barbara Alexander  
Consumer Affairs Consultant

83 Wedgewood Dr.  
Winthrop, ME 04364

E-mail: [barbalex@ctel.net](mailto:barbalex@ctel.net)

February 2007

Barbara R. Alexander opened her own consulting practice in March 1996. From 1986-1996 she was the Director, Consumer Assistance Division, at the Maine Public Utilities Commission. Her special area of expertise has been the exploration of and recommendations for consumer protection, universal service programs, service quality, and consumer education policies to accompany the move to electric, natural gas, and telephone competition. She has authored AA Blueprint for Consumer Protection Issues in Retail Electric Competition® (Office of Energy and Renewable Energy, U.S. Department of Energy, October, 1998). In addition, she has published reports that address price volatility and consumer benefits associated with the provision of basic electric and natural gas service: “Managing Default Service to Provide Consumer Benefits in Restructured States: Avoiding Short Term Price Volatility” (2003), available at [http://www.neap.ncat.org\\_experts\\_index](http://www.neap.ncat.org_experts_index), and “Natural Gas Price Volatility: Regulatory Policies to Assure Affordable and Stable Gas Supply Prices for Residential Customers,” (2004), available at <http://www.ncat.org/liheap/news/Feb04/gaspricevol.htm>. Most recently, Ms. Alexander has published an analysis of “red flag” issues associated with state consumer protection regulations, “Red Flags for Consumer Protection Policies Governing Essential Electric and Gas Utility Services: How to Avoid Adverse Impacts on Low Income Consumers” (October 2005), which is available at: <http://www.liheap.ncat.org/pubs/balexanderconsstudy05.doc>. Her clients include national consumer organizations, state public utility commissions, and state public advocates.

This report was prepared under contract with  
Oak Ridge National Laboratory UT-Battelle, LLC  
Purchase Order No. 4000049807

The opinions and conclusions expressed in this report are  
those of the author alone and do not represent  
the views of Oak Ridge National Laboratory or the  
U.S. Department of Energy

TABLE OF CONTENTS

SUMMARY OF FINDINGS AND RECOMMENDATIONS.....4

INTRODUCTION .....7

WHY ARE “SMART METERS” BEING PROMOTED AND WHO IS PROMOTING THIS  
CHANGE IN HOW ELECTRIC SERVICE IS PRICED? .....19

CALIFORNIA SMART METER PROGRAM: A SYSTEM WIDE INVESTMENT AND  
COMMITMENT TO ADVANCED METERS, ALTERNATIVE PRICING OPTIONS, AND  
DEMAND RESPONSE PROGRAMS .....29

ILLINOIS ADOPTS A REQUIREMENT THAT ELECTRIC UTILITIES MUST OFFER REAL  
TIME PRICING PROGRAMS TO RESIDENTIAL CUSTOMERS .....34

OTHER STATE ACTIONS TO CONSIDER OR APPROVE SMART METERS AND TOU OR  
CPP PRICING FOR RESIDENTIAL CUSTOMERS.....39

STATE PROCEEDINGS TO CONSIDER SMART METER INSTALLATION UNDER  
ENERGY POLICY ACT OF 2005: WHAT FACTS AND EVIDENCE SHOULD BE SOUGHT  
AND CONSIDERED IN THE CONSIDERATION OF THE SMART METER POLICY?.....53

A NOTE ABOUT DEMAND RESPONSE PROGRAMS THAT DO NOT REQUIRE SMART  
METERS OR REAL TIME PRICING: DIRECT LOAD CONTROL.....59

APPENDIX A:.....62

END NOTES .....65

## SUMMARY OF FINDINGS AND RECOMMENDATIONS

The push to install more expensive smart meters (and their associated communication and data storage systems) and consider more “real time” or volatile electricity prices for residential electric customers has the potential for significant harm to many residential customers and particularly to limited income and payment troubled customers. Almost no jurisdiction has acknowledged the potential adverse impacts on these vulnerable customers who must have essential electricity service to assure household health and safety. Nor has any jurisdiction specifically ordered an analysis of proposals for dramatic changes in the pricing of electricity on limited income or payment troubled customers.

The repeated calls to link retail prices with short-term wholesale market hourly or day-ahead prices assumes economic validity of those price signals<sup>1</sup> and requires state regulators to promote the installation of more expensive meters and communication systems to achieve their rate design goals and objectives. Whether or not the rate designs are initially labeled “voluntary”, the fact that more advanced meters are being installed or proposed for universal installation on a system-wide basis suggests that the “voluntary” label is temporary at best.

Finally, the more advanced meters with two-way communication systems carry significant implications for customer service, privacy, and consumer protection policies that have been viewed as either a benefit (as in the California Public Utilities Commission’s analysis of the cost and benefits of the system-wide installation of smart meters) or completely ignored in terms of their possible adverse implications.

At a minimum, when faced with proposals to promote smart meters or any “real time” pricing proposal, advocates for limited income and payment troubled customers should call for an analysis of the impacts of the costs and the benefits to residential customers generally and more vulnerable lower income customers specifically. This analysis should reflect a bill impact analysis to pay for the new meters and communication systems at various usage levels, as well as a consideration of the consumer protection policies and programs that presently exist and that rely on personal contact and premise visits as a crucial aspect of the implementation of the notice and attempts to avoid disconnection of service.

It would be unfair and poor public policy to leap into new metering technology and new methods of pricing essential electricity service to residential customers without a careful analysis and access to factual information on the impacts of such proposals on customer bills and usage patterns. The lack of such information is particularly glaring for low income customers.

Rather than focus on passing through “real time price signals” to residential customers based on short term or spot market prices, representatives of limited income and payment troubled customers should consider reforms being adopted in some states that are designed to ensure long term price stability and long term lowest price for essential electricity service. There are legitimate concerns that have been raised with the structure and operation of the current wholesale markets. These concerns point to the potential for market manipulation, lack of sufficient competition, and the structure of the market pricing mechanisms themselves. Wholesale

market structure and pricing mechanisms are still being vigorously debated and to rely entirely on such immature and potentially “wrong” price signals to customers who rely on essential electricity services for minimum health and safety standards should raise red flags and longer term analysis prior to embarking on expensive new metering and rate design programs.

Finally, advocates for limited income and payment troubled customers should ask for the development of the least expensive demand response programs that are likely to benefit all customers and focus on those specific customer usage profiles that are likely to contribute to the objectives of the program in the most cost effective manner. Typically, this would require an analysis of simpler direct load control programs that reward the participating customer for a modest level of interruption or appliance cycling and are typically not intended to “punish” lower usage customers with higher prices at peak usage periods. Also, a rate design change to inclining block rates could send gradual price signals to all customers as their consumption increases. In addition, proponents of real time pricing programs often claim that the reduction in peak usage would assist in the ongoing efforts to reduce greenhouse gas emissions from power plants that contribute to global warming, on the grounds that reducing peak demand will reduce the need for new generation resources. However, logic suggests that shifting more usage to off peak periods would call on increased reliance on baseload generating plants which are typically coal-fired and nuclear generation. Any claims of environmental benefit should be carefully examined to determine whether most of the peak usage is just shifted to off peak hours, thus limiting any environmental benefits associated with these programs.

Any program that is aimed at residential customers in the form of a pilot program to test TOU or CPP options or rate designs should include identified low income customers with usage that is lower than average residential customers and analyze the impacts of such programs on those customers who do not or cannot take actions to avoid the higher peak prices. Finally, any pilot programs should require an independent evaluation that asks the hard questions about whether the program as designed or implemented can be rolled out to a sufficient number of residential customers to achieve its intended objective and at what cost.

It may be wiser to focus first on the very high use sub-class of such customers who typically have the financial ability to actually respond to peak prices and the usage profile that reflects the potential peak shaving or peak load reduction that is the intended purpose of such programs. Even with this subgroup, however, there may be serious obstacles to any requirement for real time pricing. For example, New York previously had a mandatory time of use rate for very high usage residential electric customers. Despite the presumed ability of very high usage customers to adapt to time of use rates, the program was so unpopular the state legislature amended the law to make any residential time of use program voluntary.<sup>2</sup> Maine’s mandatory TOU rate program, adopted at a time of price stability, was abandoned with a dramatic increase in electricity prices and the onset of electric restructuring. Puget Sound Energy in Oregon abandoned a system-wide move to TOU pricing for residential customers when it became clear that the additional costs of the new communication and billing systems could not be avoided with average monthly bill savings.

Advocates for limited income and payment troubled customers should consider several recommendations and policies that should govern a state's consideration of system-wide smart meter programs or the move to "real time", TOU, RTP, or CPP approaches to the pricing of essential electricity service for residential customers. These recommendations are summarized in Appendix A. Under this approach, smart meter installation must be fully analyzed in a contested proceeding at the commission to determine its costs and benefits as reflected for all customer classes, with a particular requirement that the impacts on lower income residential customers be undertaken. Furthermore, any demand response or move to adopt TOU or CPP options for residential customers should be voluntary and not mandatory, with the costs of such programs paid for by the participants.

## INTRODUCTION

While electricity prices are increasing in many states due to the impacts of retail electric restructuring and higher fuel costs (particularly natural gas) used in electric generation power plants, another development is likely to have an even more significant impact on the ability of limited income and payment troubled customers to obtain and maintain essential electricity service. Federal policy, some state regulators, and advocates for “sending the proper price signals” to all customers support the installation of “smart meters” and changes in how electricity is priced. In some cases, customers will be offered the option of “time of use” or “critical” pricing programs that vary the price of electricity by the time of day or the volatile prices of a wholesale spot market. In other cases, customers will be offered the option of interrupting or reducing usage of key appliances in return for a bill credit or other means of rewarding the customer for taking actions in response to higher wholesale spot market prices. In some cases, regulators will order the mandatory installation and funding for new meters and communication technologies and make permanent changes in how electricity is priced. In general, the overall trend of these initiatives will be to raise electricity prices to pay for the new meters, installation and maintenance of the new meters, new communication facilities, new computers and software to receive and process the information from the meters, and new billing systems to implement the pricing changes. A move to make electricity prices more volatile (i.e., changing more frequently than in the past) and with more difference between “high” prices and “low” prices at different times of day or year would be a major break with longstanding state legislative and regulatory policies to stabilize rates of residential and small business consumers.

The purpose of this paper is to educate consumer advocates on the state and federal

developments that are promoting “smart meters”, “real time pricing”, and “demand response” programs for residential customers and to highlight the potential concerns and impacts of these programs and policies on limited income and payment troubled residential customers.

By “limited income” I refer to residential customers whose household income qualifies the household for participation in one or more of a State’s means-tested financial assistance programs, such as Low Income Home Energy Assistance Program (LIHEAP), Medicaid, Food Stamps, prescription drug assistance, WIC, telephone Lifeline, and similar programs. While most of these programs rely on a household income qualification that is at or below 150% of Federal Poverty Level, others use a slightly higher income qualification. In all cases, the programs are designed to assist households with insufficient income to meet their vital and essential needs for shelter, heat, electricity, medications, and food.

By “payment troubled” I refer to residential electric customers who demonstrate an inability to make regular monthly bill payments in full and who have frequent contacts with the utility concerning bill payments, enter into deferred payment plans, who frequently make only partial bill payments, or who need referrals to public assistance or charitable aid in response to notices of disconnection of service. These customers may have “limited income” but include those who are just above the more traditional definitions of poverty in many programs and who encounter bill payment difficulties.

In this paper I use the term “smart meter” to refer to a meter that has the capability to record and store information about a customer’s electricity usage by time of day and is linked to a two-way communication system with the utility. In most cases, this requires a meter other than the typical mechanical meter already installed for most residential customer electricity services. These older meters are relatively inexpensive and reliable, but they only record continuous

electricity usage with a mechanical dial. It is possible to “read” such meters more frequently (and thus obtain usage information at certain times of day), but this requires the installation of an additional communication system to access the meter reading several times a day. More typically, a “smart meter” is a new meter that has the capacity to store electricity usage according to various time periods or intervals that are programmed into the meter. In other words, the older meters are best thought of as an analog device and the newer meters as a digital device. While “smart meters” do not themselves require a two-way communication system to operate (i.e., the data they contain can be obtained with visual meter readings or by a one-way transmittal of data to the utility), typically such meters are also accompanied by a new communication technology that allows two-way communication between the meter and the utility by means of a high speed communication system that relies on radio or wireless communications, broadband power line transmission, or copper wire (telephone) communication devices.<sup>3</sup> A centralized database is maintained by the utility of continuous or frequent meter usage readings for each customer. This information can be used to issue customer bills, analyze usage profiles, and design and implement new electricity pricing programs. When the utility has direct contact with the customer’s meter, the utility can also turn the meter on and off from a central location, i.e., start service and disconnect service without a premises visit.

The term “real time pricing” is used to describe how the more sophisticated or more detailed information derived from the smart meters is used to bill end use customers. This type of pricing is also referred to by its proponents as “dynamic pricing.” Typically, smart meters are accompanied by a proposal to change the way in which electricity is priced on the customer’s monthly bill. These electricity pricing programs (known in the regulatory world as “rate design”) vary the price of electricity according to time of day or even every hour, charging more or less for

electricity based on higher production costs, in states with vertically integrated utilities, or conditions in a wholesale electricity spot market in states where distribution utilities have divested their power plants and must purchase wholesale energy for retail customers. At its most basic, “real time pricing” means that a customer is charged more for electricity at peak periods when production costs or wholesale spot market prices increase (due to high demand and the need to turn on the most expensive generating resources) and less for off-peak periods when there is likely to be a larger surplus of electricity and lower demand (and when the least expensive baseload generating units are used). In regional wholesale markets, higher peak hour prices are also a reflection of transmission constraints and pockets in which there is insufficient transmission capacity to send otherwise available electricity to customers.

The most typical type of dynamic or real time pricing programs that are being proposed and discussed in state proceedings include:

- **Time of Use or TOU** rates in which the customer’s meter records usage by hour and charge different prices for different times of day. The TOU rates usually change once or twice per year (winter and summer) and, at a minimum reflect two time periods, peak and off-peak, but sometimes also include a “shoulder” price that is midway between the two extremes.
- **Real Time Pricing or RTP** rates in which the customer’s meter records usage by hour and charges a different rate for each hour depending on movements in the wholesale spot market.
- **Critical Peak Pricing or CPP** rates in which some hours of the year during particularly high peak prices are charged a very high price. This option can be implemented with either TOU or CPP rate programs. The hours in question are

typically fewer than 1% of the hours per year and the customer is notified at least one day in advance.

By “demand response” programs, I mean programs operated by utilities or wholesale market participants in which there is an organized effort to obtain a lower demand on the electricity system (i.e., reduce usage) so as to reduce the level of the peak period or to shift usage to lower peak periods. Proponents of demand response programs often suggest that properly designed programs can substitute for building new generation or lower prices for all customers if the usage at the peak period is reduced because of the significant impact that peak period prices have on the average price of electricity charged to all customers. Demand response programs are generally of two types: (1) the use of time of use or critical peak pricing programs to require the customer to pay more for electricity based on peak and non-peak system information so that the higher price acts as a signal to reduce usage; or (2) the use of customer credits or other incentives to allow the utility to directly control the use or load of a particular appliance (such as air conditioning) during the most extreme peak load conditions, typically 20-30 hours per year. A variation would enable the customer to adjust or shut off home appliances remotely, via internet or other means, when prices rise above certain levels.

**Why should limited income and payment troubled customers be concerned about these developments?** As will be discussed further in this paper, the system wide installation of smart meters and the promotion of more volatile pricing alternatives for basic electricity service, as well as the design of some demand response programs, raise important issues for customers who have difficulty making regular bill payments and whose household income may not support higher bills in some months in return for lower bills in other months. In some cases, these

concerns are similar to those shared by all residential customers, but the impacts of these concerns resonate more deeply with customers who have difficulty making regular monthly payments based on current and rising electricity prices. Since electricity is vital to household and community health and safety, any development that may reduce the affordability of electricity should be viewed with suspicion and alarm.

First, the installation of smart meters and the new communications and data management systems required to implement the new pricing programs, the design and implementation of new billing options with changes to the utility's customer service and accounting software, as well as the consumer education and communication programs that will be required, are likely to result in higher rates or prices for all customers. Even assuming investment in this technology has the potential for lower prices in the long run, most utilities will not choose or agree to absorb these additional costs in the short run. As part of the rate recovery proposals that are likely to accompany proposals for advanced meters is a suggestion that higher meter costs should be paid for with higher fixed monthly customer charges. Any rate increase is likely to have a more significantly adverse impact in the form of higher monthly bills on limited income and payment troubled customers, but higher fixed monthly charges have a more adverse impact on lower use customers where the fixed charges represent a higher percentage of the total monthly bill.

Second, the theory of more volatile pricing and "sending the proper price signal" assumes the spot market price is correct and reflects the marginal or incremental cost for electricity. The use of smart meters and dynamic or real time pricing means that electricity is not being bought with the objective of price stability or long term management of a diverse portfolio of contracts and energy management services. In other words the meters and the new pricing trends attempt to institutionalize the wholesale spot market as the method of acquiring and pricing electricity.

This reliance on the spot market to buy electricity for residential (and small commercial) customers is directly contrary to initiatives in some restructuring states to adopt long term planning and portfolio management of electricity service and avoid the short term wholesale market ups and downs.<sup>4</sup>

Third, the use of more dynamic pricing methods assumes that every customer has the ability to respond to hourly or daily price signals. This ability is obviously easier for higher usage residential, commercial, or industrial customers who have greater flexibility for reduction or shifting the usage away from expensive peak hours and taking advantage of the option to lower bills and experience benefits. For example, an industrial customer could alter production patterns and operations to use electricity during lower cost periods. Some residential customers could lower the thermostat (for controls of home heating, home cooling, hot water, or pool pumps) at peak periods

These options are not as easily available to customers with a fairly constant usage profile or who use such a low level of electricity that there is not a great deal of elasticity in their ability to reduce or shift usage, at least without suffering some potential discomfort or harm to health. Such may be the case with many residential customers and is more likely the case with limited income and payment troubled residential customers who typically use less electricity than their higher income neighbors.<sup>5</sup> The penetration of more energy intensive appliances is lower for limited income customers than for higher income customers. On average, limited income customers reside in housing units that are typically smaller in size and require less electricity to light, heat, or cool. This is true even though many limited income and payment troubled customers live in structures that are older and not properly insulated and often rely on older and less energy efficient appliances. However, those customers with poorly insulated dwellings, in

need of repairs, or who rely on less efficient and older appliances, are the least able to fix these problems and take actions to reduce their energy usage due to their limited income. Also, low income renters may lack control over appliances provided by landlords, *e.g.*, inefficient refrigerators or hot water heaters. These factors suggest that limited income and payment troubled customers are not likely to be able to take actions in response to price signals that are available to higher income customers, such as investments in structural repairs, weatherization, upgrading appliances; purchasing energy savings control devices, etc. The only practical option available to these customers is to do without or make changes in their lifestyle or family schedules to avoid using electricity at certain times of the day, even when that may adversely impact their health. Finally, older consumers may need a constant level of heat or cooling to maintain a safe body temperature and “doing without” in the middle of a heat wave in order to avoid higher bills may result in dire health and safety consequences.

Crucial to any analysis of the impact of more volatile pricing programs on low income customers is the definition of “peak” period or hours by the local utility. If the peak electricity periods and the times of day in which electricity is likely to be priced the highest (early morning and late afternoon/early evening) are also those times of the day when most families must prepare meals (breakfast and dinner), provide heat (and cooling in warmer climates) and hot water for themselves and their children for baths and other household cleaning chores, the potential for adverse impact is higher. TVs and lights are operating when families are home, not in school, and not at work. While it is certainly possible to “teach” customers to do their laundry and operate dish washers after 8 PM, the bulk of electricity usage is not likely to be dramatically shifted for households when most of the usage relates to necessary tasks. Elderly customers and households with small children need to maintain a level heating and cooling temperature to avoid potentially

dangerous health conditions. If the peak or critical hours typically fall in the summer afternoon a residential customer is at work, the ability to reduce air conditioning usage by increasing the home temperature may not adversely impact health and safety, although any such program should pay careful attention to the impact on elderly or other vulnerable residential customers who are at home and may rely on air conditioning to avoid adverse health consequences due to hyperthermia or who are suffering illness and other medical conditions that require cooling in hot weather and additional heat in cold weather.

When electricity prices are volatile, it may be more difficult for households with limited or fixed incomes to plan and accommodate significant changes in monthly expenditures. For example, limited income households are not necessarily benefited if the average annual electricity bill is lower when relying on higher peak period prices during some months of the year and lower than standard rates in other months or times of the year. If the size of any monthly bill is driven by high peak period prices or frequent critical peak hours, the unexpected expense can throw a customer into the nonpaying and collection cycle. Utility payment plans are unlikely to provide a solution when the bill is unaffordable unless the customer can shift the higher than normal bill into pay periods that correspond with lower bills. Any typical payment plan offered by utilities requires the customer to make a downpayment on the overdue amount and make regular monthly payments on the arrears balance along with the future monthly bills in full. While some claim that budget payment plans are useful tools for blunting fluctuations in bills, they are designed to average seasonal variations in a customer's consumption over the year and work best when prices are fairly constant. For a heating customer, the use of a budget payment plan shifts some of the winter bills impacts to the lower use summer bills. This payment option would blunt the intended impact of making customers “see” the higher prices at times of the wholesale system peak and

respond to those high prices in real time. The use of TOU and CPP pricing makes the calculation of estimated future bills for a 12 month period more difficult and perhaps impossible. Furthermore, some utilities will not allow a customer in arrears to enter into a budget or leveled payment plan.

Fourth, the reliance on more volatile pricing options for residential service and the resulting impact on customer bills may have an unforeseen impact on the policies and delivery mechanisms with existing energy assistance programs. For example, the use of TOU or CPP options may result in higher overdue amounts, thus triggering more frequent requests for assistance and for higher amounts. If utilities can remotely disconnect service with such systems without the need for a field visit - and the possibility of a field payment, this is likely to increase the volume of disconnections, with the accompanying impacts on customers, communities, and social service agencies. Another impact may be the expansion of those who may have managed to “make do” under the prior method of charging for electricity prices but now require emergency financial assistance.

Finally, the installation of smart meters and their accompanying communication systems will allow utilities to remotely read, energize, and disconnect service. A likely result will be the increase in the volume of disconnections because such automated systems avoid the need to schedule field personnel and premise visits. Most utilities do not actually disconnect all those customers eligible for disconnection in any week or month due to operational constraints and the need to prioritize such field work with other operational obligations. Premise visits and “truck rolls” are expensive and often result in utilities making choices about the volume or type of disconnections that occur at any time. Also, field payments are sometimes made to forestall termination when the disconnection is being made or the field worker is made aware of a potential

medical emergency that leads to a delay while the occupant obtains the necessary confirmation from a medical professional. When access to the meter can be accomplished remotely, utilities will not need to prioritize disconnections based on the amount overdue, for example, unless they choose to do so for other reasons. Furthermore, the elimination of the need for premise visits to effectuate the disconnection carries significant implications for current regulations in effect in many states that require the utility to attempt personal contact with the customer prior to disconnection in order to determine if a medical emergency is present or offer payment arrangements. As a result, reliance on remotely controlled meters is likely to result in a degradation of consumer protection and customer service compared to current practices.

**Does this mean that any demand response program or TOU or CPP pricing option should always be opposed as harmful to limited income or payment troubled customers?**

Not necessarily, because the “devil is in the details.” The programs that are most likely to have a positive impact, i.e., lower customer bills and contribute to lowering peak usage at a modest system-wide cost, are those that are referred to as “direct load control” demand response programs. In such programs, the customer’s appliance, typically an air conditioner, is directly hooked into the utility’s communication system and interrupted or cycled on and off for a few hours during critical peak periods. In return, the customer who chooses to participate may enjoy a near invisible impact on household comfort, the benefit of reduced usage on the monthly bill, and a customer reward or credit provided as an incentive to participate in the demand response program. Several examples of this type of program are described later in this paper. This type of program does not require advanced metering and the investment in the direct communication equipment is typically modest and far less than the savings seen by the utility in their management

of peak usage. In other words, under such programs, customers who choose to participate may see benefits and little or no costs.

It is also possible to construct a CPP option that results in customer bill savings if there is a highly supervised customer communication and interaction program that links the advent of high peak usage prices with actions that the customer can easily implement without adverse impacts on household activities or health. Under this type of program, it is up to the customer to take actions to reduce usage or shift usage to avoid the extremely high prices charged at a “critical peak” period. If the frequency of such CPP events is relatively low and the customer communication and education aspects of the program are well designed and successful, this type of program can be implemented without adverse impacts on health and safety IF the customers participating in the program have the ability to avoid usage or shift usage during these high price hours.

Rate options, such as TOU and RTP, in which all customer hours are designed to reflect short term wholesale market prices and pass through spot market prices, are more likely to be of questionable value and may pose significant bill impacts on limited income customers. Very little research has been done on the widespread costs, bill impacts, usage patterns, and system benefits of these programs, yet they are being widely discussed and promoted in many states.

## WHY ARE “SMART METERS” BEING PROMOTED AND WHO IS PROMOTING THIS CHANGE IN HOW ELECTRIC SERVICE IS PRICED?

When the U.S. Congress enacted the Energy Policy Act of 2005,<sup>6</sup> most observers focused on the provisions that contained directives for energy efficiency, renewable resources, tax breaks and initiatives for coal, oil, and nuclear energy, new federal authority to ensure more reliable transmission systems, as well as the repeal of the Public Utility Holding Company Act of 1935. But buried in Subtitle E of Title XII (Electricity) are several amendments to the Public Utility Regulatory Policies Act of 1978 (PURPA). Sections 1251, 1252, and 1254 of the 2005 Energy Policy Act amend the “Retail Regulatory Policies for Electric Utilities (Title I) of PURPA by adding new federal policies<sup>7</sup> that are applicable to state regulation of electric utilities. Section 1252 contains a new “smart metering” standard. The standard requires that each electric utility offer to each of its customer classes and to individual customers upon request a “time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility’s costs of generating and purchasing electricity at the wholesale level.” The time-based schedule “shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology....”

The statute also sets forth the types of time-based rate schedules that may be offered, including “time of use pricing (TOU)” in which prices are broken into two or three time periods and are fixed for some period, but which may change twice per year; “critical peak pricing” (CPP) in which TOU pricing is used except for a few hours per year in which the utility can increase peak prices to a substantially higher level to reflect wholesale market conditions; “real time prices” (RTP) in which prices are provided to the end use customer to reflect the actual or real wholesale market conditions on an hourly or daily basis, typically with a very short notification of

forthcoming price changes; and the use of credits for customers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.<sup>8</sup>

Under PURPA, the federal government appears to directly regulate or set standards for electric utilities. But, another section of PURPA defers to state authority over retail electric service and requires state regulators to "consider" the federal standards within one year of the enactment of the federal standard and complete the determination of its consideration within two years of the enactment of the federal standard, i.e., August 2007 based on the 2005 Energy Policy Act's enactment date.<sup>9</sup> If the state does not complete its determination within this time frame, PURPA then requires the state to consider and determine the federal standard at the time of the utility's next base rate case. A state can avoid any new determination entirely if it has already implemented the standard or a comparable standard, if the state regulator has considered the same or comparable standard within the previous three years before enactment, or the state's legislature has voted on the implementation of the standard or a comparable standard within the previous three years before enactment. The apparent reason for the ultimate deference to the states is that regulation of such matters traditionally is a matter of state concern and has not been preempted. Indeed, the PURPA requirement that a state must consider the original PURPA agenda was narrowly upheld by the Supreme Court in a divided opinion.<sup>10</sup>

The result of the new amendments and the PURPA language is that there is now a clear federal standard that supports "smart meters" and the exploration of the new pricing methods such as TOU, CPP, and RTP for all customer classes. While state regulators and nonregulated (electric cooperatives or publicly owned) electric utilities are not required to offer all customer classes the option of these new meters and alternative electric pricing methods, the fact that states

are required to conduct an analysis of these options means that the proponents of this new federal policy will be eager to participate in state proceedings and argue for these policies and programs. Whether representatives of residential customers generally or limited income and payment troubled customers will be at the table is a legitimate concern.

Why do the proponents of smart meters, TOU, CPP, and RTP push for these changes in the way electricity is priced? At its core, the simple explanation is that economists believe that prices for resources should be set so that those who consume the resources will reflect when the resource is scarce and when the resource is plentiful. Under the classic economic theory, a scarce resource should reflect a high enough price to drive the providers of the resource to invest in new capacity or find a new way to satisfy customer wants and needs through technological innovation or substitution of another product. When electricity is priced to reflect the average cost of all the generation units and all the times of day in which electricity is used, the impact of the most expensive generating unit and the time of day when prices are higher due to the highest level of demand (the peak), is not seen by end use customers. Proponents say they do not see the “real” price of electricity and cannot make decisions about their usage to reflect the peaks and valleys in electricity prices. Under this theory, consumers who see the “real” price of electricity will alter usage patterns or reduce usage during the most expensive periods. Alternatively, those who must use electricity at the most expensive times will pay the “real” price and investors in new generation facilities will see the potential for profits if new generation is produced to serve this need. When generation unit prices and times are averaged, those who need to see the potential for a profit on new merchant power investment may not be paid enough to generate such investment. When a vertically integrated utility sees that it is paying higher prices for running less efficient peakers in more hours, or that capacity reserve margins are shrinking, it may take those

price and reliability signals into account and may build new capacity, or take other action to reduce load, through DSM programs, or shift peak usage through rate design changes. In contrast, most end users lack power to address a peak price signal by building a new baseload plant.

This economic theory has been used in the context of electric utility regulation for many years, and there are many instances of time of day or seasonally differentiated rates under conventional regulation in states that do not have spot markets. The full import of this approach was muted with traditional regulation in which the utility was allowed to recover the costs of higher priced or more expensive generation and average that price with lower cost generation in its total generation portfolio. However, in jurisdictions where restructuring occurred, many utilities no longer own generation and they rely almost exclusively on the wholesale market for generation. Regulators are now allowing those wholesale prices to be passed through to retail customers, after transitional retail rate freezes or price caps expire. In the restructured states, an independent owner of generation without long term contracts that assure recovery of costs and a return of and on capital may not be able to recoup the costs of new generation and make a profit if it depends on selling in spot markets, all of which have constraints on charging very high scarcity prices at key peak periods.

This promotion of new metering technology and alternative pricing methods for electricity service also resonates with those who seek to make sure that prices are set to reflect the costs that are caused by the particular customer class or sub-class. For example, these proponents argue that if the reason why peak usage occurs is primarily due to residential and small commercial usage late in the afternoon or early evening, those customer classes should pay the higher prices associated with that usage. If a large commercial or industrial customer can shift usage to off

peak periods or operate a night shift to make their widgets, they should pay the lowest price for electricity. Some refer to this as a reduction in “cross subsidies” which can occur between different customer classes and within a customer class, if total revenue from one of the classes does not cover the incremental cost of serving them.

Other proponents of smart meters and new pricing methods also suggest that these innovations allow utilities and other market participants to better manage the electricity grid to make more electricity available at certain key times or reduce the need for investment in new transmission or generation facilities. This can be accomplished by monitoring usage patterns in greater detail and taking actions at the wholesale level to assure that the transmission system and the dispatching of various generation units is more closely matched to actual need or used as a means of triggering interruption programs or events to prevent blackouts and reduced reliability generally. These programs are typically called “demand response” programs because they are intended to target the reduction in demand or a shift in demand usage in response to peak prices and wholesale market conditions. In states where vertically integrated utilities still own generation, new generation, transmission, or demand response mechanisms, or a combination of them, can be used in conjunction with rate design changes to achieve the desired level of system efficiency and balance of supply and demand.

Finally, proponents of smart meters and new pricing methods emphasize the potential for improved customer service by allowing the utility to read meters remotely (and eliminate meter readers and the issuance of estimated bills) and issue accurate bills, program new billing changes and pricing options into meters and offering these optional programs to customers, detect and respond to meter tampering and energy theft, and improve collection activities by allowing meters and services to be remotely started or disconnected without premise visits or personal contact at

the customer's residence. Data mining of such electricity usage data could indicate when customers get up in the morning, whether they use electricity during working hours, when they leave and return, whether and when they use significant air conditioning or other motors, whether they are home weekends, whether they have been terminated for nonpayment, when they take vacations, etc. Utility handling of customer usage data has been considered in telecommunications regulation, with the general result that customer proprietary network information (CPNI) obtained by the utility as a result of the customer's usage generally is to be protected from release to any third parties, and must not be released without consent, subpoena or warrant. Privacy implications from gathering customer real time electricity usage data are largely ignored and need to be addressed.

The following quotes and excerpts from national publications reveal a wide ranging support for the installation of smart meters and, more importantly, the more volatile pricing methods that will be possible as a result of the new metering and communication systems:

- § Rates that are based on highly averaged costs blur the price signals to customers, and result in an inefficient allocation of resources, referred to by economists as "deadweight loss" to society. These deadweight losses have been well known for many years but there is still a need to "break away from uniform rates and substitute rates based more accurately on cost." The benefit of smart metering is that it makes it more feasible to price electricity at its real cost through time. This, in turn, can lead to the elimination (or, more realistically, the reduction) in deadweight losses, thereby promoting social welfare.<sup>11</sup>
- § In response to a question concerning moving to an energy-only pricing in the wholesale market and eliminating locational marginal pricing, "We can get rid of every bit of that tomorrow, if every state will allow the full floating price every five minutes to be reflected in the customer's bill." Further, "Up and until the time that states will allow retail customers to see the real-time prices, and pay the real-time prices, you're forced to create square-peg/round-hole solutions; to create surrogates for scarcity pricing."<sup>12</sup>
- § The automated collection of advanced or "interval" energy use data is necessary to enable energy market participants to more closely match energy supply with demand.

Balancing energy supply and demand will become increasingly important to making the new competitive energy marketplace work in a cost effective and reliability manner. By collecting more advanced metering data, a utility can build a body of knowledge to develop an entirely new portfolio of dynamic rate structures and incentive programs, real-time pricing packages and interruptible rates that can be targeted to specific customers to significantly improve load management capabilities and reduce peak demand when distribution system conditions become critical.<sup>13</sup>

- § With the appropriate remote control technology, the utility—via the call center—will be able to process connect and disconnect requests the same day, and without a truck roll. Further, delinquent accounts can be monitored and address—and service disconnected—without lag time between service order generation and its execution at the customer location. This ability to connect and disconnect remotely while reducing the required number of truck rolls has the ability to significantly reduce these operating costs.<sup>14</sup>
- § The Demand Response and Advanced Metering Coalition emphasizes the importance of “customer control over their energy bill” in promoting smart meters and new pricing programs. DRAM states that residential customers “are better at managing their energy budgets; they have what economists call a higher price elasticity of demand” and such customers “deserve the same chance to lower their bills as businesses.”<sup>15</sup>
- § At the present time, because of price caps and rate protocols, prices don’t rise high enough to provide adequate signals. It’s always a good idea to provide consumers with better price signals, so they can increase or decrease consumption accordingly. But if you give consumers prices that are wrong or too low, they won’t react to those prices. Until you integrate the system-operation protocols with prices and demand-response system, you won’t get the incentives you need.<sup>16</sup>
- § Although demand response programs can provide benefits, they face three main barriers to their introduction and expansion: (1) state regulations that shield customers from short-term price fluctuations; the absence of equipment installed at customers’ sites required for participation; and (3) customers’ limited awareness of programs and their potential benefits.<sup>17</sup>

Implicit in real time pricing strategies is a shift away from the longstanding traditional utility responsibility, still incorporated in the statutes of most states, to provide adequate service upon demand at reasonable, predictable prices, and toward a new regime in which utilities and regulators expect customers to react to system inadequacies or deficiencies by using less or paying more.

The Federal Energy Regulatory Commission (FERC) has completed a recent survey of all states in the use of smart meters, alternative pricing methods, and demand response programs.<sup>18</sup> Based on the results of this survey, FERC reported that there is only a 6% penetration of advanced metering on a national level, but the penetration rate for such meters varies by type of utility and region. For example, 13% of the rural electric cooperatives have installed advanced meters. The highest level of advanced meter installation occurs in Pennsylvania, Wisconsin, Connecticut, Kentucky, Idaho, Maine, Missouri, and Arkansas. Nationally, only 5% of customers are on some form of time-based rates or incentive-based rates that relate to peak usage periods. FERC has stated its desire to promote and encourage demand response programs and the wider use of advanced meters. In this Report, FERC identified the following regulatory barriers to increased use of demand response and peak pricing programs:

- There is a failure to link wholesale markets and wholesale prices with how retail prices appear on customer bills.
- Utilities have disincentives to promote demand response generally because it may reduce utility sales and its revenues and profits are linked to selling more electricity.
- There is no clear policy concerning the incentives to stimulate utility investment in advanced meters and new communication and data management systems and cost recovery mechanisms have not yet been resolved.
- The business case to demonstrate that benefits exceed the costs for the widespread installation of advanced meters, new communication and data management systems has not yet been made.

- There are State-level barriers to more widespread adoption of demand response programs and the use of some pricing methods in the form of state law and policy that protects some customers from being exposed to volatile prices.
- There is not yet a resolution of how to link the wholesale markets to retail rates and prices, specifically the difficulty in linking actions taken by retail end use customers with wholesale market payments.
- The third parties or new market participants who seek to promote advanced meters need more assurance of longer term funding to expand their ability to market and produce the new meters and communications software.
- There is insufficient market transparency and access to data on prices in the wholesale market.
- There is a need for better coordination of federal-state jurisdictions to coordinate policy initiatives between the retail and wholesale markets.

Implicit in FERC's analysis is an assumption that wholesale spot market prices are a correct economic signal. Many economists would identify marginal cost as an appropriate pricing signal, but the wholesale markets are based on sellers' demands, not their costs. FERC apparently assumes that spot market prices approach incremental cost, but that assumption is not universally accepted. There is a growing body of academic and technical study showing that auction pricing of goods such is highly susceptible to market manipulation and overcharging.<sup>19</sup> If spot market prices are inflated due to strategic bidding, or are subject to manipulation, or for other reasons do not reflect incremental cost, as many contend, then the price signals for end use customers will be incorrect. Closing manufacturing plants, sending shifts of workers home on hot days, inefficient investment signals, or subjection of low income households to considerable hardship and suffering

all could flow from unthinking transmission of deeply flawed spot market price signals to end use customers.

CALIFORNIA SMART METER PROGRAM: A SYSTEM WIDE INVESTMENT AND  
COMMITMENT TO ADVANCED METERS, ALTERNATIVE PRICING OPTIONS, AND  
DEMAND RESPONSE PROGRAMS

While there is little “progress” as yet made in the widespread installation of smart or advanced meters and the use of more volatile pricing methods for residential customers, no State has taken more dramatic steps than those undertaken or planned in California. The State’s Energy Action Plan identifies several key action items with regard to Demand Response, including the proposals to adopt advanced metering by the large electric utilities, educate Californians about the time-sensitivity of energy use and how they can participate in demand response programs, and incorporate demand response appropriately and consistently into the planning protocols of the California PUC, the California Energy Commission and the wholesale market administrator. As early as 2001, California had already rolled-out interval meters for large customers with usage in excess of 200 kW and the placement of those customers on time-of-use tariffs. Starting in 2003, the investor owned electric utilities were ordered to develop new demand response programs and tariffs for customers as well as expand existing emergency triggered programs. At the same time, California adopted an aggressive long-term dynamic pricing goal for the utilities equal to 5% of the projected system peak demand in 2007.

In a Report<sup>20</sup> to the California Legislature by the California Energy Commission in October 2003, these potential adverse impacts of real-time, critical peak, and other dynamic pricing scenarios on some customers were noted:

Dynamic pricing can more accurately charge customers for their cost of service than do existing fixed rates. As a result, customers subsidized under current rates are most likely to pay more under dynamic pricing. In particular, any customer that uses more energy during peak periods than the average customer, and who cannot or will not shift their usage in response to price signals, is likely to pay more under dynamic pricing. Most

customers should not be protected from paying the real cost of purchasing and delivering electricity to their homes. Truly “disadvantaged” customers, i.e., low income and medical necessity customers, could be provided with an explicit subsidy if the dynamic rates actually result in higher bills for them.

A fixed monthly charge for interval meters may increase bills for some low-usage customers. Options to ensure protection of these customers include the following:

- Require that the costs of new interval meters be recovered through volumetric energy rates rather than fixed charges.
- Provide customers below a certain usage level with a credit or subsidy.
- Do not provide interval meters to low-usage customers.

In this Report, the California Energy Commission also challenged the notion that low use or low income customers would necessarily be harmed by dynamic pricing. Using a simulation analysis, the Commission analyzed the impact of a 5 percent shift in usage from on to off-peak and another scenario with no shift in usage for customers using less than 350 kWh per month and reported that the resulting average monthly bill would be at least \$1.00 lower under critical peak pricing compared to existing standard rates (which, in California, are already tiered to reflect significantly higher prices for increased usage). At the time of this Report, the Commission reported that the range of costs and benefits for installing the necessary advanced metering and communication systems for California’s investor owned electric utilities ranged from a net benefit of \$6.91 per meter per month to a net cost of -\$2.45/meter/month.

In 2003-2004, California conducted statewide pilot programs for residential customers and tested a variety of pricing and demand response options.<sup>21</sup> Customers were solicited to participate in the program based on geographic and demographic diversity. Specifically, three pricing options were tested: (1) a traditional TOU where the price during the peak period was 70% higher than the standard rate and about twice the value of the price during the off-peak period; (2) a CPP tariff in which the peak period price during a small number of critical days was

about five times higher than the standard rate and about six times higher than the off-peak price, but with a fixed critical period and day ahead notification; and (3) a CPP tariff similar to (2), but where the peak period on critical days was variable. The Commission had approved the pricing pilots with certain constraints, namely,

- experimental rates had to be revenue neutral for the class-average customer over a calendar year,
- the rates not change the bill of low and high users by more than 5% in either direction, and
- customers must be provided with the opportunity to reduce their bills by 10% if they reduced or shifted peak usage by 30%.

These constraints resulted in using rates that would result in using a high price ratio in the summer and a low price ratio in the winter so that the annual revenue neutrality obligation could be met. Finally, it is important to consider that low income electric customers in California are provided a 20% rate discount under the CARE program.

The evaluation of these pricing programs for residential customers found that the use of TOU prices alone reduced consumption by 6%, but the authors noted that this may be due in part to the “modest” nature of the differential in the pilot TOU prices between peak and off peak periods. Indeed, the impact of time of use rates on residential consumption in general “almost completely disappeared” by the second year. However, the use of CPP or critical peak pricing reduced usage on Critical Peak days by 13-16%, thus showing that those customers with the largest energy usage (particularly those with central air conditioning) could have a potentially significant impact on usage during expensive peak periods. Finally, the pilot programs found that usage reduction (27%) significantly improved with installation of “smart thermostat,” that is, the use of a module

in the customer's home that enabled the customer or the utility to program cooling usage based on network conditions. However, since California law appears to prohibit the use of CPP for residential customers on a mandatory basis<sup>22</sup>, it is not clear how these results can be translated into system-wide cost effective programs at this time.

Most importantly for the implications of such pricing methods for limited income customers, the impact evaluation of the California Statewide Pricing Pilot<sup>9</sup> found that "the elasticity of substitution for CARE [low-income discount] customers is essentially zero."<sup>23</sup>

All of California's investor owned electric utilities have filed proposals for the installation of advanced meters and associated communication systems throughout their service territories with the California PUC. In July 2006, California PUC approved PG&E's proposal to replace all electric and gas meters with "smart meter" technology over five years at a price tag of \$1.6 billion.<sup>24</sup> This initiative (and the similar plans proposed by Southern California Edison and San Diego Gas & Electric that are still pending before the PUC) is a direct result of a statewide policy to rely on smart meters and demand response programs to reduce peak load in an attempt to reduce electricity prices and the need to construct expensive new generation facilities. However, the PUC's decision did not mandate that residential customers take electricity under a demand response tariff. Rather, TOU price plans will continue to be available on a voluntary basis to such customers. The Commission stated its objective to promote TOU pricing for residential customers and will require ratepayers to fund education programs to this end in addition to the cost of the meters and ancillary communication and data management systems. It should be noted that current California law prohibits the use of Critical Peak Pricing for residential customers, but the PUC also approved a new voluntary CPP price option that will be offered to residential

customers for certain summer peak usage hours. This CPP tariff is likely to price electricity as high as 60 cents/kWh during certain summer peak afternoon hours.

The new meters were evaluated as beneficial over a 20-year pay back period and the PUC rejected the arguments of the primary consumer intervener that the proposed level of investment and type of meter architecture proposed by PG&E was not cost effective for the residential class and that a more modest and targeted investment should be approved at this time. However, the Commission acknowledged that the primary benefits identified in the proposal were not related to demand response savings, but savings related to the use of remote meter reading, remote connection/disconnection, and outage management. The Commission's analysis also relied heavily on the proposed CPP option to have an impact on actual demand reduction during peak periods. The Commission found that 90% of the costs associated with the metering initiative would be recovered through operational savings and only 10% through demand response benefits.

ILLINOIS ADOPTS A REQUIREMENT THAT ELECTRIC UTILITIES MUST OFFER  
REAL TIME PRICING PROGRAMS TO RESIDENTIAL CUSTOMERS

One of the more intriguing real time pricing pilot programs targeted to residential customers has been operated on a pilot basis for three years in Chicago, Illinois by Community Energy Cooperative, a local community organization in cooperation with Commonwealth Edison (ComEd). Participating customers were provided a new interval meter and charged hourly prices for electricity based on the PJM ComEd zone day ahead hourly locational marginal price. These meters were not “smart meters” because they lacked two-way communications between the meter and the utility. Rather, the meter recorded usage on hourly intervals, but was manually read by an electronic probe and the usage information downloaded to the utility billing system.

Customers were informed of these day ahead hourly prices via an email communication or they accessed the same information on the Community Energy Cooperative website. When an hourly price was slated to hit a predetermined trigger, customers were specially notified of that event. This trigger was initially set at 10 cents/kWh for 2003-2005, but starting in mid-2005 the trigger was changed to 13 cents per kWh due to the frequency of the high wholesale market prices that occurred in the summer of 2005 and the high prices for electricity due to the impact of the Gulf Coast hurricanes on natural gas prices. Customers are informed that their absolute maximum hourly price would not exceed 50 cents/kWh, but this maximum hourly price was not reached during the term of the program even during the high prices of mid-2005. The program was initiated in 2003 with approximately 1,000 participating residential customers. By 2006, 1,500 customers were participating. All participants were volunteers.

During this period, the first two summers were milder than normal and few hours hit the 10 cents/KWh trigger. However, during the 2005 summer, temperatures were higher and

wholesale electricity prices rose more frequently over that notification trigger—a total of 360 hours. During the three-year period, other residential ComEd customers were charged a rate of 8.275 cents/kWh for summer months and 7.475 cents/Kwh for non-summer months. As a result of the high hourly prices in 2005, participating hourly price customers often saw bills that exceeded those of standard rate customers, but their non-winter bills were typically lower than ComEd's other residential customers.

According to an evaluation of the program done by Summit Blue Consulting<sup>25</sup>, the program has demonstrated that residential customers, including those who are low income<sup>26</sup> and participating in the program, will respond to price signals and reduce usage during peak periods, typically by moderating their air conditioning usage. The option of an automatic air conditioning cycling program added to the pilot in 2004 increased the usage reduction during peak price hours. Participating customers with access to the hourly prices and program information on the community organization's website and who received notification of the high price hours via e-mail were more responsive than those without computers or who received notification of high price hours via telephone. However, the evaluation did not find any distinction between single family homes and multi-family dwellings in their reaction to the price structure.

The Summit Blue analysis did not address bill impacts. However, the Energy Cooperative has bill impact information that has been used to make public presentations concerning the results of the three-year program. According to a spokesperson, the monthly bills for participants were lower than the equivalent bills under ComEd's residential rates in every month but one between February 2003 and August 2005. Beginning with August 2005 (the onset of warmer summer weather and higher wholesale market prices), the average bills for the participants were higher than ComEd's residential rate bills for August through January 2006.<sup>27</sup>

Two aspects of this program bear closer analysis. First, the evaluations done to date and the website materials concerning this program do not provide any bill impact analysis based on the household demographics or appliance saturation of the participating customers. While the Summit Blue evaluation states that customers reduced usage 3-4% on average (i.e., that usage reductions in the peak hours in the summer were not just shifted to other time periods), the impact of this usage reduction under the hourly prices and other participant incentive mechanisms provided by the program do not tell the full story. How many customers and with what demographic and usage profile had higher bills during the summer than would have occurred with the standard rates?

Second, the pricing mechanisms of this program appear complicated and its “low tech” method of interacting with customers concerning information about hourly prices may not be possible to duplicate on a mass scale, particularly for those customers without access to the web and frequent electronic communication. The pricing components of the pilot program require the customer to understand the hourly pricing mechanism, the basis for how the hourly prices are set, as well as a “monthly access charge” and a participant incentive fee. The former was set once per year and was intended to represent the distribution or fixed fee portion of a customer’s bill. It appears that this fee (which was initially set at 3-4 cents/kWh and then reduced to less than 1 cent/kWh in 2006) was intended to be used to modify some aspects of the growing wholesale market prices that occurred in 2005 and 2006. In addition, participating customers were provided a 1.4 cents/kWh credit as an incentive to participate in the program. As a result, participating customers were given an artificial benefit that would not otherwise be available to all customers should such a program be implemented on a mass scale.

With the onset of new electricity prices for the Illinois electric utilities in January 2007, the pilot program operated by Community Energy Cooperative ended. As of January 2007, ComEd's generation prices increased an average of 22% (plus a distribution rate increase) as a result of the end of the rate cap period and the unbundling of all customer bills between distribution and generation components. Prices for residential customers of Ameren utilities in the southern portion of Illinois increased by a higher average amount of 50%.<sup>28</sup>

In part as a reaction to this pilot program and interest in hourly pricing, the Illinois Legislature enacted a bill in April 2006 to expand real time pricing rate options to more residential customers. The new law requires ComEd and Ameren utilities to provide all customers with "access to and be able to voluntarily use real-time pricing and other price-response and demand-response mechanisms." "Real-time pricing" is defined as "tariffed retail charges for delivered electric power and energy that vary hour to hour and are determined from wholesale market prices using a methodology approved by the Illinois Commerce Commission." The electric utilities are required to file a tariff to allow residential customers to elect real time pricing beginning January 2, 2007, provided that the Commission finds that the "potential for demand reductions will result in net economic benefits to all residential customers of the electric utility." Utilities are required to install an interval meter capable of recording hourly energy use for any customer that elects real time pricing. Such election must be continued for a minimum of 12 months. The utilities are authorized to recover the reasonable costs of the program and its administration by imposing most costs on those participating in the program, but some portion of the costs on all residential customers, providing the Commission finds that the cost savings resulting from the real time pricing program will exceed the costs imposed on customers for maintaining the program.<sup>29</sup>

Both ComEd and Ameren have announced prices and terms for their real time pricing option for residential customers. The ComEd program<sup>30</sup> seeks to enroll up to 110,000 residential customers. These customers will pay an additional meter charge of \$2.25 per month. They will be charged hourly prices based on the PJM spot market. The hourly pricing information will be available to customers from the utility's third party program administrator, Converge. ComEd was authorized by the Illinois Commission<sup>31</sup> to recover all the costs associated with operating this program (in addition to the increased monthly meter charge) through a separate surcharge mechanism that is charged to all residential customers. The current cost recovery amount for the real time hourly pricing program is \$0.14 per month. The program administrator is required to conduct an evaluation of the programs costs and benefits by 2008. This program, and a similar one available to Ameren customers, was supported by consumer organizations on the grounds that participating customers could lower their monthly bills compared to the higher generating prices that resulted from the wholesale market auction (which these same organizations have vehemently opposed) by relying on the lower prices for electricity for off peak hours. Under this reasoning, customers who can deal with price volatility will reduce peak usage sufficiently to reduce prices for all customers in future wholesale market auctions. Whether this in fact will occur remains to be determined, but in the meantime all customers will pay to support this experiment.

## OTHER STATE ACTIONS TO CONSIDER OR APPROVE SMART METERS AND TOU OR CPP PRICING FOR RESIDENTIAL CUSTOMERS

In 2001, following the Western market implosion caused in part by the market manipulations of Enron, **Puget Sound Energy in Washington** promoted a TOU pricing plan for all residential customers that was touted as a means of reducing customer bills and savings for the electric system overall. The utility did not replace existing mechanical meters, but installed a communication system that allow the utility to remotely read the meters several times a day and record usage and bill customers under the new peak, off peak, and shoulder prices approved by the Washington Utilities and Transportation Commission (WUTC). Unlike many proposed TOU rates, the Puget Sound proposal reflected a fairly modest differential between peak and off peak prices which was a reflection of the Northwestern hydro-based power market. The peak price was about 15% higher than the average price that customers had faced in their prior standard rate. An analysis of the results in 2002 did not show these intended benefits.<sup>32</sup> According to the evaluation, 94% of the customers were paying an extra \$.80 per month under the TOU rates, consisting of \$.20 in power savings and \$1 in incremental meter costs (as a result of the new communications system).<sup>33</sup> Consumers complained loudly about the program and the lack of savings, claiming that they had in fact shifted significant usage to off peak hours. The program did in fact shift energy usage and customers did see a modest bill savings as a result, but the administrative costs of the program were greater than the individual customer bill savings under the prices in effect for this program. According to one observer in Washington who followed the development and implementation of this program, those customers with the highest bill impacts (i.e. who experienced higher bills) were those living in mobile homes and multi-family dwellings, housing types typically associated with lower income customers. In 2002, Puget

Sound Energy filed to terminate the experiment ahead of schedule and the program was abandoned.

**Central Maine Power Co., Maine's** largest investor owned electric utility, initiated TOU rates for high use residential customers in the early 1980's, partly in response to the enactment of PURPA following the energy crisis that occurred as a result of the oil embargo and run up in oil prices at that time. The Maine PUC made this program mandatory for residential customers who used more than 2,000 kwh in any winter month and the costs of the new TOU meters were charged to the participating customers in the form of a fixed monthly charge. The program was aimed at customers who were presumed to be using electric space heat for this winter-peaking utility. The program was justified both as a means to provide high use customers with the option of reducing their bills by shifting usage from peak hours (early AM and late afternoon/early evening) to non-peak periods and as the implementation of a public policy to send the proper price signal to those with electric heat so that they would pay prices that reflected their incremental or marginal costs imposed on the system. This program was the source of minor annoyance from affected customers that became louder and more widespread when electricity prices rose substantially for all customers and particularly for the on-peak TOU prices in the early 1990's. In addition to the imposition of this rate structure on larger residential homes, many of the affected residential TOU customers resided in subsidized and elderly housing developments, all of whom had installed electric heat with the cooperation of the electric utility as a clean and more convenient alternative to the traditional fuel oil heating systems prevalent in Maine. It should be noted that natural gas penetration in Maine is very small and the price of fuel oil rose dramatically during the oil embargo and subsequent shortages. In response to the higher peak prices and the customer complaints about the rate structure itself, a number of public initiatives

were undertaken to retrofit the heating systems for these multi-unit dwellings and, where customers could afford to do so, a replacement of electric heat by alternative heating systems occurred. Even so, the mandatory nature of the TOU program triggered significant public and political opposition. In 1996 the Commission opened an investigation into CMP's rate design, specifically including whether there should continue to be mandatory TOU for residential customers, and later in this docket proposed to eliminate mandatory TOU rates for residential customers, citing the "frequent source of customer confusion and dissatisfaction concerning the pricing structure of CMP's electric service."<sup>34</sup> CMP then proposed to eliminate the mandatory feature of TOU for residential customers and retained TOU rates as an optional service, in part to accommodate those households that had already installed electric heat pumps and other means to store heat in lower peak usage periods and release it during the higher peak periods. Further changes to this optional rate structure were adopted when Maine adopted electric restructuring in 1999. The peak and off peak nature of the optional TOU rate was limited to the regulated distribution portion of the bill and those TOU customers that remain receive Standard Offer or default electric service for the generation portion of their bill in the form of a flat rate, similar to all other residential customers.

More recently, **Public Service Electric & Gas in New Jersey** proposed a variety of demand response as "MyPower" pilot programs for residential customers in 2004. While part of the Company's initial filing, a prepayment pilot program was subsequently withdrawn. Three programs were approved, one was a utility activated load management program targeted to air conditioners, one was a TOU/ CPP option that was "education only", and the third was intended to test a CPP pricing option. The CPP option was described as "day ahead hourly technology enabled" and would have informed customers of hourly prices on a day ahead basis. The New

Jersey Board of Public Utilities approved the three programs in late 2004 and authorized their implementation over two summers in 2005 and 2006 with deferred accounting approval for the estimated cost of \$3.77 million.<sup>35</sup> However, only the load control program was implemented in 2005 with results that mirror other programs of this type in that most customers were not aware of interruption or cycling of their central air conditioner. The day ahead pricing experiment was abandoned when it became clear that the prices that would be charged to participating customers were high enough as to make them unacceptable and unavoidable with the modest load shifting activities that are available to residential customers. According to the New Jersey BPU order authorizing the abandonment of the CPP day ahead pilot, “Essentially, because of the high level of PJM hourly energy pricing, especially in the summer peak times, compared to [default service] pricing, PSE&G realized that participants in the My Power Manager pilot would see an increase in their monthly bills regardless of whether they shifted their usage to the off peak, and therefore the purposes of the program would clearly be thwarted. Additionally, customers in the MyPower Manager pilot would further be harmed because the Company includes the recovery of the generation and transmission obligation costs through an arbitrary flat 10 cents per kWh adder to all summer weekday afternoon hourly energy rates between 1 pm and 6 pm. Consequently, customers volunteering to participate in this voluntary program intended to reward them for curbing their energy usage during peak periods would in fact likely pay more.”<sup>36</sup>

Similar to New Jersey, the **District of Columbia** Public Service Commission has supported demand response programs generally and has supported the design of a “smart power” pilot program for **Potomac Electric Power Company’s (Pepco)** residential customers. Since the District adopted electric restructuring, Pepco has been authorized to provide Standard Offer Service to residential customers relying on relatively short-term wholesale market contracts (one

to three year terms with fixed prices) that have resulted in significant price increases for all customers in the last three years.<sup>37</sup>

The program details were designed by the District of Columbia Smart Meter Pilot Program, Inc., composed of Pepco, District of Columbia Office of the People's Counsel, District of Columbia Consumer Utility Board, the IBEW, and the Commission. The program will operate for two years and is limited to 2,500 customers, some of which will compose the control group. Significantly, the costs of the program will not be passed along to any participating or other customers because Pepco agreed to conduct this program without additional charges as part of a previous merger settlement approved by the Commission. As a result, it is not clear how a cost benefit analysis can be done based on the program that will be operated in this pilot.

Participants will be billed under one of three pricing options: Hourly Pricing, Critical Peak Pricing, or Critical Peak Rebate. About half the customers in the program will receive smart thermostats that can automatically reduce energy consumption during the high priced-periods. Under the Hourly Pricing program, prices will vary hourly based on day ahead spot wholesale market prices. The prices will be posted on a website and available by calling a toll free telephone number. Pepco has estimated that hourly prices would exceed the standard residential price only about 1/3 of the time within a year, with prices lower than the standard rate the rest of the time. The Critical Peak Pricing customers see two pricing options: critical peak prices and prices for all other hours. There will be 12 critical peak days in the summer and 3 critical peak days in the winter. Prices during these critical peak periods will be substantially higher than standard residential prices. Customers will be notified of these events the day before via an automated phone call, email, text page, or smart thermostat notification. These higher prices can be offset by lower prices in the other days and hours of the year. Under the Critical Peak Rebate pilot,

customers will pay the standard rate, but will receive a rebate for reducing usage during the critical peak hours below that which they would normally use.

After a delay in final approval of these pilots based on its stated concerns about the scope and extent of consumer education for program participants, the potential for “shocks” to customers in wholesale market prices due to recent events, the lack of any parallel billing system so that customers can readily see how their bills under the pilot programs compare to those under standard rates, and the Commission’s proposal that pilot participants be given the option to select a predetermined default position in terms of usage reduction and educated about the impact of various default options in terms of bill savings during critical peak periods or high hourly prices,<sup>38</sup> the Commission finally approved the two-year pilot program on January 12, 2007. According to the Commission, “Customers participating in the project will have the ability to have greater control over their electricity consumption and an opportunity to reduce their monthly electricity costs.”<sup>39</sup> The Commission’s final approval also outlined five primary factors that the programs will measure: (1) reductions in consumption during peak periods; (2) changes in overall customer consumption; (3) customer satisfaction with the varying pricing options and technologies; (4) the usefulness of new technologies; and (5) the value of offering additional pricing information to customers. The Commission declined to require parallel billing to participating customers because Pepco stated that such a billing requirement would be burdensome.<sup>40</sup>

A larger and more robust TOU program with critical peak pricing features has been implemented by **Gulf Power (a Southern Company) in Florida**. The Good Cents Select program is a voluntary program that enables customers to control their energy usage by programming their cooling and heating systems, water heater, and pool pumps to automatically respond to varying prices. Under this pricing program, there are four daily rating periods with the

Low, Medium, and High rates set by tariff and reflecting the typical TOU rate structure. These prices vary between winter and summer periods. A fourth rate is named “Critical” and while the price for this period is set, the times at which it is in effect is a reflection of wholesale market system peak conditions, but this rate is charged only a maximum of 1% of the annual hours. The program requires the customer to accept a programmable thermostat and an interval meter for an additional charge of \$4.95/month. The current prices are 6.8 cents/kWh for low period, 8 cents/kWh for medium periods, 12.6 cents/kWh for high periods, and 33.5 cents/kWh for critical periods. The standard electric price is 8.9 cents/kWh. The utility advertises this program as a means of controlling energy usage, lowering bills, and that the communications gateway may “someday provide access to services likely cable TV and the internet.” Customers are educated to program the thermostat for their key electrical appliances to turn off during peak periods, particularly the water heater which acts as a storage device and can retain hot water for many hours. Customers with electric heat experience the greatest savings. Based on customer surveys, Gulf Power claims that over 90% of the participating customers are satisfied or very satisfied with the program and that “the overwhelming majority of participating customers experience lower monthly electric bills.”<sup>41</sup>

**Connecticut’s** 2005 amendments to its Electric Restructuring law require electric utilities to offer mandatory Time of Use (TOU) meters and TOU pricing for larger commercial and industrial customers and optional TOU pricing for residential customers by June 2006, as well as mandatory seasonal rates for all customers by April 2007.<sup>42</sup> The statute requires that the utilities demonstrate that such programs and rates be cost-based and cost-effective and that they will not have adverse impacts on affected customers. Customers must also have access to a comparative bill analysis. The Connecticut Department of Public Utility Control (DPUC) recently completed a

formal proceeding to implement this directive for Connecticut Light and Power, the largest electric utility. Because the utility demonstrated that its existing metering and billing system would not allow the implementation of some of the statutory mandates in 2007, the DPUC ordered the following changes for residential customers<sup>43</sup>:

- Implementation of voluntary TOU tariffs for residential customers by January 2008;
- Implementation of mandatory TOU rates in a phase-in beginning January 2009;
- Implementation of mandatory seasonal rates beginning April 2008; and
- Shift a greater portion of distribution rate recovery to monthly fixed charges rather than energy rates over the next five years.

While CL&P currently offers TOU rates to its residential customers, only 135 of the 1.1 million residential customers take service under this option. The vast majority of residential customers are on a standard tariff that is intended for non-electric heat customers, but 140,000 customers are on a tariff intended for electric heat customers. The DPUC ordered CL&P to eliminate the electric heat tariff and restrict residential customers to either the non-electric heat tariff or the TOU tariff. Furthermore, the TOU peak and off periods will be redesigned so that an eight-hour peak will result from 12 p.m. until 8 p.m. on weekdays (40 on-peak hours per week), with all other hours designated as off-peak. The DPUC noted that this rate design would allow consumers to shift usage to the morning hours or after 8 p.m. in the evening. Only the generation portion of the customer bill will reflect these TOU differentials so that the distribution rates and fixed customer charges will remain undifferentiated and the same as the regular residential rate. The actual determination of the new TOU rates must occur after the utility obtains generation supply pursuant to the new rate design requirements in the next procurement for default service,

but the DPUC stated that a “meaningful” differential between peak and off peak rates should exceed 5 cents/kWh.

Even though not required by law, the DPUC also ordered CL&P to implement a mandatory TOU rate program starting with the largest residential usage customers. The program was ordered even though there was no record evidence concerning the impact of the TOU rate structure on these customers and the utility provided evidence on the significant costs associated with the required installation of new meters and impacts on the utility’s billing system. No information was provided on a cost benefit calculation or costs associated consumer education. Rather, the state regulators relied entirely on its belief that it must take steps to reduce peak usage demand, which drive a significant portion of Connecticut’s electricity prices: “The Department believes by expanding and mandating TOU rates that more CL&P customers will seize the opportunity to reduce their electric costs by controlling their on-peak demand.”<sup>44</sup> Starting with those that use 8,000 kWh or more in any month, residential customers will be required to take electric service on TOU rates starting in 2008, with lower usage thresholds transferred to TOU rates each year until 2013 when customers with usage above 2,000 kWh in any month will be transferred to TOU rates.

The linkage between retail electric competition, smart meters, and the potential advent of more volatile pricing for residential customers is most evident in **Texas**. Under a Texas PUC proceeding on smart meter deployment and dynamic pricing, the Commission’s proposed rule<sup>45</sup> would authorize the distribution utilities to assess a surcharge to recover costs for advanced meter deployment to encourage “dynamic pricing and demand response.” While deployment of advanced meters would be voluntary, any such deployment must comply with the rule’s

requirement that the utility file a deployment plan and that the advanced meters meet certain minimum specifications. The advanced metering features include:

- Automated or remote meter reading;
- Two-way communications;
- Dynamic pricing options;
- Remote disconnection and reconnection capability;
- Transmittal of meter data to the independent regional operator or RTO;
- Provision of timely customer usage data to retail electricity providers;
- Capability to allow the retail electricity provider to “provide signals relating to price, in order to effect demand response”;
- 15-minute interval data;
- Storage of meter data;
- Open standards architecture; and
- Ability to upgrade minimum capabilities in the future.

TXU Electric Delivery (the distribution utility) currently has over 160,000 advanced meters installed on its system. The company plans to continue to install advanced meters at a rapid pace to cover the entire service area. Deployment began in 2005 without any guaranteed method of cost recovery, but the utility is likely to seek a PUC-approved surcharge for this system shortly. The communications technology chosen by TXU will be Broadband Power Line in high density areas, with power line carrier (PLC) for the remaining low density and rural areas.<sup>46</sup>

Comments filed by consumer representatives<sup>47</sup> opposed the notion of allowing an electric utility to file and implement a deployment plan for advanced metering to residential customers without any showing of either costs or benefits prior to obtaining approval of a surcharge that

would raise all customer electricity prices. Furthermore, these Comments raised important consumer protection policy issues that were not addressed in the Commission's actions to date:

The deployment of advanced meters will entail a wholesale change in the way the industry performs the metering function. Despite all the claimed benefits, advanced metering in many ways represents a brave new world that will be less friendly and less forgiving to customers. Today, electric utilities and TDUs [transmission and distribution utilities] have a level of knowledge through their field personnel regarding individual customer circumstances beyond usage-i.e., conditions on the ground-that will be largely nonexistent once this new infrastructure is deployed. That knowledge of the customer often prevents bad things from happening such as a disconnection that would affect health and safety that are not strictly prohibited under the customer protection rules. Further, the customer protection rules as currently written are based on an industry model that will no longer exist once advanced metering systems are widely deployed-manual meter reads. This rulemaking should focus on what additional customer safeguards will be necessary to ensure that the new model does not erode current customer protections or cause other harmful consequences that have not been anticipated.

Another state that has made the link between electric restructuring and dynamic pricing is **Massachusetts** where the Massachusetts Division of Energy Resources has proposed an investigation into the potential benefits of implementing dynamic pricing for all residential customers taking "standard" or "default" service from electric utilities.<sup>48</sup> In its petition seeking the formal proceeding filed with the Massachusetts Department of Telecommunications and Energy (DTE), the energy office stated, "This petition argues that consumers would be better served by a dynamic pricing structure more closely aligned with the wholesale price of electricity. In particular, DOER proposes a change in the structure of basic service to provide time of use rates, or equivalent, for residential and small commercial and industrial customers, and real time pricing for large commercial and industrial customers." Pointing out that wholesale prices vary dramatically from hour to hour but that standard rates do not vary during the day or week, "As a result, during peak demand periods, consumers are encouraged to consumer more than they

would if they were aware of the real cost to provide the electricity.” The DTE has requested public comment on whether such an investigation should occur and its scope. Just as it has in Connecticut, ISO New England, Inc. (the regional transmission organization) supported the proposal, saying that “it firmly believes that dynamic prices that link retail energy prices and wholesale power costs, rather than using highly averaged prices that mask the cost variability of supplying electricity at different times of the day, will allow customers to benefit from altering their consumption patterns.” The basic premise of this benefit is that if peak demand is reduced, all customers will benefit. Other proponents of further exploring this pricing option for all customers include the Demand Response and Advanced Metering Coalition and the Retail Electric Supply Association (representing a coalition of retail energy marketers).<sup>49</sup> Low-income consumer representatives<sup>50</sup> emphasized the lack of any cost-benefit data in the DOER petition concerning the implementation of more volatile pricing mechanisms for residential customers and particularly low use or low income residential customers:

Additionally, any analysis of cost-effectiveness should separately consider customer sectors and sub-sectors, including the small and low-income residential sub-sectors. Such analysis should also take into account adverse external costs to customers, such as the cost of new equipment to take advantage of time-differentiated rates. It should be recognized that there are customers who cannot reduce their demand at peak and it is not equitable to raise the bills of such customers because of that fact. For all these reasons, if the Department opens a docket on dynamic pricing, it should explicitly limit it to customers other than small and low-income residential customers.

US Department of Energy data show that, other than air conditioning and swimming pools, only about 16 percent of residential load (itself only about a third of total load) is devoted to domestic hot water (DHW) heating and laundry uses and thus might be partially shiftable by customers without an investment in new controls or other sacrifice (though DHW shifting would require a control device). Since only a small fraction of such load can actually be shifted, it is apparent that the potential available small residential peak load reduction is not very large.

Not only does DOER not offer evidence of much benefit from applying dynamic pricing to small residential customers, it concedes that it has no information to offer about the cost

of achieving whatever benefit there may be (at 29) and therefore has no evidence that it might be cost-effective to make the investments required (at 27). Similarly, DOER does not discuss negative externalities from small residential dynamic pricing (e.g., customer costs of technology), which would reduce cost-effectiveness even further. DOER has thus failed to make a *prima facie* economic showing that a Department investigation of dynamic pricing for small residential customers would be worth the substantial public and private resources required to conduct the investigation.

**New York** has emphasized the imposition of mandatory hourly pricing and advanced meters for large customers only. New York introduced mandatory real time pricing for large customers as part of its initial restructuring vision in which all customers previously served by distribution utilities would be migrated to new competitive retailers. A device used to stimulate migration away from the utility was the elimination of any utility price hedging and portfolio purchasing, and the adoption of RTP rates that simply pass through real time NYISO spot market prices. A research study of a National Grid Real Time Pricing (“RTP”) rate program for large non residential customers observes:

“Actual customer experience with RTP is limited and thinly documented and as a result adaptive behaviors are not well understood. . . .This study examines the experience of 130 large (over 2 MW) industrial, commercial and institutional customers at Niagara Mohawk Power Corporation that have faced day-ahead electricity market prices as their default tariff since 1998. *It is the first study of large customer response to RTP in the context of retail competition.* . . .In October 1998, with the commencement of retail access in New York, NMPC replaced the existing time-of-use (TOU) tariff for large customers (>2MW) served under the “SC-3A” class with an RTP rate design. . . .Only 45% of survey respondents have installed DR-enabling technologies since 1998. 54% indicated they were not price responsive at all; of the rest, most employ “low tech”curtailment strategies and do not reschedule usage. Average price response estimates are modest: the overall substitution elasticity is 0.14. Surprisingly, government/educational customers display the highest response (0.30); industrial response is similar to past research findings (0.11) and commercial customers are least responsive (0.00). . . .The experience in New York has shown that retailers may not offer adequate hedging options, so policymakers implementing RTP should ensure that such opportunities exist so that customers can choose the level of risk exposure they are comfortable with.”<sup>51</sup>

In sum, this research indicates that the National Grid program did not involve residential customers, the participants in the RTP program were very large customers, presumably the most able to adjust their usage, yet most of them were not price responsive to RTP day-ahead rates, and price hedging opportunities through alternative retail electric companies were not readily available. Any notion that large customers can readily shift their usage or endure fluctuating rates is undercut by orders of the New York PSC that required a utility that had sold its plants to make available fixed price long term service to its largest customers, e.g., Deferiet Paper (a customer otherwise subject to Niagara Mohawk's RTP prices), Corning, Inc. and NUCOR. Steel.<sup>52</sup>

The New York Public Service Commission is operating under statutory guidance that has been interpreted to prohibit the use of mandatory time of use rates for residential customers.<sup>53</sup> The statute was adopted while Consolidated Edison was in the midst of implementing a mandatory TOU program for some residential customers. The Commission interpreted the new law to prohibit such programs and ordered ConEd to make the program voluntary in 1997.<sup>54</sup>

STATE PROCEEDINGS TO CONSIDER SMART METER INSTALLATION UNDER ENERGY POLICY ACT OF 2005: WHAT FACTS AND EVIDENCE SHOULD BE SOUGHT AND CONSIDERED IN THE CONSIDERATION OF THE SMART METER POLICY?

Under the Energy Policy Act of 2005, the State has a great deal of flexibility in the type of proceeding it undertakes to consider the “smart meter” policy directive. Furthermore, States have the option of relying on a recent proceeding within the past three years (which may be an investigation or a consideration of the policy in a utility’s base rate case) to satisfy the statutory directive.

A perusal of the state proceedings that are currently underway indicates that they range from an informal notice with working groups, rulemakings (such as the Texas proceeding described in the last chapter), to formal investigations with evidence and orders (as appears to be contemplated in Massachusetts).

Any proceeding in which the Commission has indicated that it intends to consider the “smart meter” policy contained in the Energy Policy Act of 2005 should be noticed on the Commission’s website. Furthermore information is likely to be available from the state’s public utility advocate or the Commission’s Staff.

The approach underway in Indiana is worthy of consideration because it appears, unlike other state proceedings in which the regulators appear to be already predisposed to focus on the benefits associated with more widespread use of smart meters and real time or time of use pricing, the Indiana Commission has outlined a specific list of fact-based information or evidence that it seeks to obtain to consider the new federal policy. In April 2006, the Indiana Utility Regulatory Commission posted a Staff White Paper that identified the issues that are required to be addressed as a result of the Energy Policy Act of 2005, including the smart meter policy. A data request

was issued to the electric utilities. After those responses were received the Commission initiated a formal docket to take evidence (in the form of testimony and exhibits) during 2007. After outlining the statutory provisions of the smart meter provisions of the Energy Policy Act and the types of time of use pricing identified in the Act, the Commission's Pre-hearing notice<sup>55</sup> sought evidence on the following issues:

With respect to each of these time-based rates the parties should consider and evaluate each market sector -residential, commercial and industrial- and determine whether these time-based rates may be appropriate for the customer classes within each utility. As part of their evaluation of time-based rates the parties should consider each pricing structure as an alternative means of achieving an identified goal within each sector.

***Identification of Goals and Objectives.*** Identification of Goals and Objectives is an important step to ensure that time-based rates can be examined and evaluated compared to other alternatives. Development of appropriate goals, and examining how the goals may be interrelated, is necessary if the time-based rates are to be fully evaluated and compared to alternative means of achieving specific goals. Identification of goals may include the following issues:

1. Reduced total demand
2. Reduced peak load demand
3. Mitigated price spikes
4. Mitigated market power
5. Increased reliability
6. More efficient use of current capacity
7. Lower consumer bills
8. Lower energy price
9. Reduced emissions
10. Others.

The discussion of goals could appropriately include identification of a primary goal or identification of multiple objectives that could be achieved along with consideration of the possible interrelationship of identified goals. Evaluation of goals could also include consideration of non-time-based rate options that are available, such as traditional demand side management programs and other load control mechanisms, and the implications of such an approach compared to the possible implementation and utilization of time-based rate options.

***Framework for CostBenefit Analysis.*** The implementation of a time-based rate program would require utilities to invest in meters, data collection and handling tools, communication devices, other infrastructure, and supporting technologies. Therefore, as

part of this proceeding, consideration should be given to the costs of implementing a given technology as well as the benefits in terms of cost savings and maintenance. Potential benefits to consider include, but are not limited to, the following:

1. Mitigated price spikes in the cost of purchased power in wholesale markets
2. Mitigated market power
3. Increased reliability
4. Environmental benefits
5. Reduced energy prices and/or lower consumer bills
6. Reduced operational costs for utilities

In examining the possible benefits the parties should consider whether benefits will vary across utilities, municipalities, cooperatives, consumer sectors and between the various time-based rates. Consideration should also be given to any interaction of benefits; whether there are additional benefits; and, if benefits that have been identified can be attained in a more cost effective manner using alternative means. Ultimately a determination should be made regarding the extent to which benefits will accrue to customers, the utility, and the wholesale market generally. Consideration of costs is also an important part of this proceeding. Potential Costs to consider include, but are not limited to, the following:

1. Investments in meters and other infrastructure
2. Administrative costs
3. Technology and data collection upgrades
4. Support for technology and data analysis
5. Consumer education and customer service
6. Costs to consumers in the form of inconvenience, price risk, or production interruption.

In considering the issue of cost the parties should fully analyze the potential type and level of administrative costs that would be required to support and promote a time-based metering program and whether increased customer service will be necessary to respond to issues that may arise as a result. This should include an analysis of the specific factors that may impact the costs of installing new meters and how the choice of communication and data collection technology will affect overall costs. With respect to the issue of responsibility for costs incurred, the parties' analysis of this issue should include a determination as to whether some groups will benefit more than others from the implementation of time-based rates. Assuming that the costs associated with time-based rates should be recovered, consideration should be given as to how these costs will be recovered (*e.g.*, a connection fee for the meter, inclusion of costs in rate base in a rate case, some other charge to consumers) and whether customers that do not participate directly in time-based rate programs should bear any of the costs. As part of the analysis of this issue the parties should consider how program participation and overall price responsiveness may change depending on how costs are recovered.

**Additional Issues.** This proceeding may also appropriately include examination of the following issues:

- 1) how utilities could educate and inform customers about the programs;
- 2) whether a decision can be reached regarding the implementation of time-based rates without consideration of specific details of the programs being developed;
- 3) whether the success of a time-based rate program depends on the exact form of rate structure being implemented, *e.g.*, if TOU or CPP are chosen, then the difference between peak and off-peak pricing may be the difference between success and failure of a program;
- 4) consideration of the tools available to help customers hedge against price risks and, to the extent such hedging tools are available, consideration of the impact these tools could have on participation and customer responsiveness to price signals;
- 5) consideration of the role that participation in a Regional Transmission Organization plays in the process; and,
- 6) if wholesale exposure to market prices is sufficient to realize full demand response potential.

The identification of these issues and the evidence that will be necessary to reach a decision on this matter is derived in part from an analysis of the Energy Policy Act's PURPA amendments and state obligations to consider the new PURPA policies (including the smart meter policy) published by the National Association of Regulatory Utility Commissioners (NARUC).<sup>56</sup>

However, even this list of key issues and evidence fail to identify the particular and potentially adverse impacts of such proposals on limited income and payment troubled customers. Therefore, the above outline of issues and evidence should include the following additional items:

- 1) Any analysis of the costs and benefits concerning the installation of smart meters or the implementation of TOU, CPP, or other form of "dynamic" or "real time" pricing for residential customers should include an analysis of bill impacts on residential customers at various usage levels or sub-classes, including those customers who are identifiable as "low income" due to their receipt of LIHEAP or other utility discount or bill assistance program.

- 2) Any demand response proposal that is aimed at residential customers should include an identification of the bill impacts associated with the achievement of specific demand response goals and objectives (i.e., peak usage reduction, shifting or reducing usage) on various usage levels or sub-classes of the residential class, including those customers who are identifiable as “low income” due to their receipt of LIHEAP or other utility discount or bill assistance program.
- 3) Any proposal to conduct a “pilot” program for TOU, CPP, or other form of “dynamic” pricing for residential customers should specifically include a representative sample of low income customers with usage that is lower than the residential class average. Any evaluation of the pilot program should identify the impacts of the program and its results on all residential customers at various usage and income levels, both in terms of costs, benefits, and bill payment impacts. Furthermore, any pilot program evaluation should include an analysis of the implications of such a program, if implemented system-wide, on consumer protection policies and programs.
- 4) An analysis whether spot market prices are accurate indicators of system marginal cost. If the intent is to pass through the “real” cost and if that is deemed to be a measure of marginal cost, it still cannot be assumed that ISO/RTO real time spot prices are accurate indicators of marginal cost. There has been inadequate attention paid by FERC to research and mathematical analysis indicating that spot market prices are readily and regularly inflated to prices far above marginal cost. Other measures, such as inclining block rates or the use of predictable, differentiated time of day prices may send better signals to customers for determining their usage and efficiency investments than erratic and inaccurate spot market signals.



## A NOTE ABOUT DEMAND RESPONSE PROGRAMS THAT DO NOT REQUIRE SMART METERS OR REAL TIME PRICING: DIRECT LOAD CONTROL

A number of utilities have initiated demand response programs that do not rely on real time or dynamic pricing to achieve their intended objective of reducing peak load usage. These programs are typically referred to as “direct load control” because they consist of a direct utility connection or communication with a particular appliance in the customer’s home. Under certain predetermined peak periods, the utility interrupts or cycles the appliance to achieve its system goal of reducing peak usage and system costs. Typically, such programs focus on residential air conditioning or hot water heaters. These programs do not require a different meter or the installation of a two-way communication system. Furthermore, these programs are typically a “win-win” for participating customers because they receive the benefit of a lower bill that reflects their lower usage (unless the customer shifts usage and increases usage in the off peak periods) and an incentive credit or bill rebate for participating in the program. In most cases, customers do not “notice” or suffer adverse consequences for the interruption or cycling.

A typical version of this program type was Baltimore Gas & Electric’s Energy Saver Switch initiated in the late 1990’s (prior to the onset of retail electric restructuring). The utility installed a radio-controlled switch on participating customer’s air conditioners. The device turned off the outside condenser unit of the air conditioning system on and off with fifteen minute intervals. The design of this system insured that the indoor fan would continue to operate and assure indoor air circulation. Participants received a bill credit as a reward for participation. This program was widely used and in 2001 over 240,000 switches were installed which reduced total summer load by 239.1 megawatts.

Other programs of this type are offered by most Florida and other utilities in the South where central air conditioning is prevalent. Florida Power & Light's "On Call" program installs an energy management device in the customer's home, connecting it to one or more qualifying appliances. FPL pays customers up to \$161 per year in credits on their electric bill and more than 600,000 customers are currently enrolled in this program.

Another well-known residential demand response program was operated by Allegheny Power in 2001. After installing a programmable thermostat for the customer's air conditioning, a signal was sent by the utility to the customer's thermostat when wholesale prices are high that changes the setting upwards on the thermostat. A signal also appeared on the thermostat so the customer could make a decision to accept the higher setting and receive a reward or override the signal and lower the setting.

A demonstration project sponsored by the Association for Energy Affordability<sup>57</sup> in New York may prove to have intriguing results for low income customers. This project revolves around a large, low-income multi-family complex in Far Rockaway, New York where the units were built in the 1970's with baseboard electric heat. While each unit had a thermostat (many of which were not working properly), the building was not submetered. Working with local Weatherization Program agencies and the public utility, the Association developed a wireless network that would provide a thermostat function in each unit, but with all the units linked together in an energy management system, thus allowing system wide information and system wide controls from a central location. This system allowed for automated temperature reductions for night and more active demand management of usage throughout the complex. Substantial energy savings were realized just from the night setback function alone with minimal customer complaints. The project was calculated to result in a 14% energy management savings for the

first three month period (October through December 2005). Of course, the unique features of the housing units (master metered, electric heat) and the nature of the New York electric pricing structure (high prices with monthly variability based on short term wholesale market conditions) all should be taken into account when considering this project.

There are several aspects of these programs that are common and worthy of consideration by consumer advocates. First, these programs do not require the mass installation of smart meters and their associated two-way communication systems. Second, the programs seek to reward customers to allowing the utility to take actions to reduce usage or cycle a specific appliance that is unlikely to have any adverse health impacts on the customer's household and will result in a lower monthly bill and the receipt of an incentive reward payment. Third, these programs are typically targeted to high use residential customers, but should be considered for lower use customers as well, particularly limited income or payment troubled customers who reside in multi-family dwellings.

Another lower tech solution could be the provision of devices that would enable customers to see the cost of their usage faster. A customer normally does not see the cost of consumption until the next month when a bill is received. Most customers do not watch their meter spin and note changes in its speed when they turn on or shut off appliances. There are devices simpler than smart meters that do not require communication of data to the utility which could display, say, month to date usage and cost, yesterday's usage and cost, today's usage and cost, the hourly cost of current usage, etc.. With such equipment, a customer would then be better able to see more swiftly and directly the cost consequences of usage, in time to unplug wasteful appliances, etc., without the cost of smart metering and without unpredictable price spikes of RTP.

## APPENDIX A:

### RECOMMENDATIONS FOR STATE POLICIES CONCERNING SMART METERS, DEMAND RESPONSE, AND REAL TIME PRICING FOR RESIDENTIAL CUSTOMERS

- (1) In general, a state regulatory commission should not require a residential customer to take electric service on a rate that is based on time of day or hourly pricing unless the customer agrees to accept such a rate schedule voluntarily. Any such program should be revenue neutral and not adversely impact the rates charged to other ratepayers.
- (2) Any proposal for a mandatory time-based rate or hourly pricing program should be targeted to a sub-group of residential customers with usage that is documented to be “high” and a usage profile that contributes to the utility’s peak price for electricity and for which there are reasonable grounds to find that a mandatory program for such a sub-group of residential customers will have benefits that exceed the costs of the proposed rate schedule, including the cost of the meters and communication network necessary to implement the rate proposal.
- (3) A program that is made available to customers who qualify for any state-administered means tested financial assistance program, including, but not limited to the Low Income Home Energy Assistance Program, Medicaid, Food Stamps, WIC, telephone Lifeline, and similar programs, should be offered without additional charge and the incremental costs recovered through existing universal service or public benefit programs.
- (4) The costs for any smart or advanced meters and associated communication network associated with a proposal to install such meters shall be paid by the customers who take service under one or more rate schedules that require the use of such meters.

- (5) The commission should not require any residential customer to install an advanced or smart meter as a condition of receiving basic or standard electric service. The commission should not approve any proposal to install or accept a prepayment meter as a condition of receipt of basic or standard electric service.
- (6) Before approving any demand response program for residential customers, the state commission should be required to find, after notice and hearing, that the benefits to all residential customers exceeds the costs associated with the implementation of the program over a reasonable period of time. Benefits should be concrete and quantifiable and may include improved reliability of service, assurance of adequacy of generation supply, and reduction in adverse environmental impacts associated with the generation of electricity from non-renewable fuel resources. In making this determination, the commission should consider the costs of the load response program, including, but not limited to, advanced metering, communications networks, administration of the program, billing and customer communication and education programs, as well as training for utility employees.
- (7) Commissions should require proponents of demand response programs that will test or institute more volatile pricing for residential customers to document the impact of such a proposal on a wide variety of residential customers, both in terms of housing type, demographic characteristics, usage profiles, and income levels.
- (8) The commission should not approve any demand response program for residential customers that is not voluntary or that is likely to have an adverse impact on residential customers generally or shift costs to those who use less than the average amount of electricity.

**(9)** The commission should not approve a demand response program that seeks to isolate or establish a condition of service either in the form of a particular meter or rate option as a result of a customer's ability to pay for electric service.

**(10)** Any demand response program for residential customers should be accompanied by a consumer education program, the cost of which should be included in the analysis of costs and benefits required prior to approval of any such program.

- a.** The purpose of a consumer education program should be to inform customers of both costs and benefits associated with the voluntary demand response program, including how to compare the impact of the demand response program on the customer's monthly and annual electric bill under traditional rate options.
- b.** Prior to approval of any demand response program, the Commission should review and approve the accompanying customer education program after finding that the program was developed with and approved by an advisory committee of members that represent the customers to whom the demand response program will be targeted.

## END NOTES

---

<sup>1</sup> Under the market structure used by most of the Regional Transmission Organizations, the most expensive generating unit's price governs the price paid to all other generating units, even low cost baseload units, that run during that hour. The market clearing seller is paid the price he demands, not the cost of producing the next megawatt. Nevertheless, real time pricing proponents assume that the winning bid represents the system marginal cost, and that it is rational for all consumers to pay that price even if, say, 95% of the energy being produced costs less, and even if the lower cost power plants could produce more if they were running to full capacity. As a result, erratic and incorrect pricing signals may be sent through real time pricing systems.

<sup>2</sup> "The Commission is not authorized to mandate time-of-use rates for residential customers. . . . Chapter 307 of the Laws of 1997 amended [New York] Public Service Law § 66(27)(a) to delete a provision authorizing the Commission to mandate time-of-use rates for residential customers, in the public interest." In the Matter of Competitive Opportunities Regarding Electric Service, In the Matter of Competitive Metering Proceeding on Motion of the Commission to Investigate Competitive Metering for Gas Service, Case 94-E-0952; Case 00-E-0165; Case 02-M-0514, New York Public Service Commission, (Issued August 1, 2006).

<sup>3</sup> The term "smart meter" as used in this paper is not necessarily the same as Automated Meter Reading (AMR) systems. A number of utilities are installing AMR throughout their service territory. In some cases, these systems do have "smart meter" technology and communication systems built into the design, even if not yet implemented. In other cases, the AMR technology is merely an add-on to current meters that can only communicate usage information to the utility and does not allow utility remote communications to the meter.

<sup>4</sup> See, e.g., Alexander, Barbara, "State Developments Changing for Default/Standard Retail Electric Service," National Gas & Electricity, September 2006. This article describes the recent statutory reforms adopted in Delaware, Maine, Rhode Island, and Maryland to require regulators and utilities to undertake long term portfolio planning and management of default or standard offer electric service for residential and small commercial customers with the objective of reducing price volatility and achieving the long term lowest price for this essential service.

<sup>5</sup> In projecting the impact of 2006 prices on low income households, a report by the Economic Opportunity Studies found that, "Those in poverty spend the least; their average bills in all climate regions, fuel types and housing types will be about \$1452. The LIHEAP-eligible group and the higher income population will pay, on average, \$1612 and \$2018, respectively. This evidence that low-income consumers historically use far less energy than the rest of U.S. households, about 82% of the average, suggests that they have fewer ways to cut bills through minor behavioral changes that do not cause them real hardship." Power, Meg PhD, FY 2006 Energy Bills Forecast: The Impact on Low-Income Consumers (February 2006). Available at [www.opportunitystudies.org](http://www.opportunitystudies.org). The analysis of household usage is derived from the U.S. Department of Energy's Residential Energy Consumption Survey (2001).

---

<sup>6</sup> Energy Policy Act of 2005, Pub. L. No. 109-58, enacted August 8, 2005. The final version is over 1,700 pages.

<sup>7</sup> Three new federal PURPA standards concerning net metering, fuel diversity, fossil fuel generation efficiency, and interconnection standards for distributed resources (on-site generation facilities) are not addressed in this paper.

<sup>8</sup> 119 Stat. 594 (2005). This paper does not address the fourth category of dynamic pricing concerning credits for customers with large loads that help a utility avoid new capacity investments.

<sup>9</sup> Energy Policy Act of 2005, Section 1252(g).

<sup>10</sup> *FERC v. Mississippi*, 456 U.S. 742 (1982) <http://caselaw.lp.findlaw.com/cgi-bin/getcase.pl?court=US&vol=456&invol=742> In dissent, supported by three other justices, Justice O'Connor stated: "The power to make decisions and set policy, however, embraces more than the ultimate authority to enact laws; it also includes the power to decide which proposals are most worthy of consideration, the order in which they should be taken up, and the precise form in which they should be debated. PURPA intrudes upon all of these functions. It chooses 12 proposals, forcing their consideration even if the state agency deems other ideas more worthy of immediate attention. In addition, PURPA hinders the agency's ability to schedule consideration of the federal standards. ... Finally, PURPA specifies, with exacting detail, the content of the standards that will absorb the agency's time." Subsequent opinions and changes in court composition since 1982 cast significant doubt on the vitality of *Mississippi v. FERC*.

<sup>11</sup> Gordon, Kenneth, Olson, Wayne, and Nieto, Amparo, "Responding to EAct 2005: Looking at Smart Meters for Electricity, Time-Based Rate Structures, and Net Metering," (Edison Electric Institute, May 2006), at 13-14.

<sup>12</sup> Interview with Phillip G. Harris, President and CEO of PJM Interconnection LLC, *Public Utility Fortnightly*, October 2006, at 41. The development of locational marginal pricing and capacity programs in the wholesale market is one response to the inability of generators to pass through and of customers to see bills that reflect extraordinarily high prices that reflect scarcity of generation resources or transmission at certain hours of the year. According to Gordon van Welie, President and CEO of ISO New England who was interviewed in this same PUF issue, "To ensure resource adequacy in an uncapped energy market, it's been shown that you would need to have prices in the range of \$10,000/MWh to \$20,000/MWh for 20, 30, or 40 hours a year, in order to recover the capital costs of a peaker, or a quick-start unit." At 45.

<sup>13</sup> Iron, Inc., "The Critical Role of Advanced Metering Technology in Optimizing Energy Delivery and Efficiency: A report to the U.S. Department of Energy," (undated).

---

<sup>14</sup> Peres, Kirby, “The Future State of AMI: Asking All the Right Questions,” Spark ( a publication of Public Utilities Fortnightly), July 2006, page 3.

<sup>15</sup> DRAM, “Demand Response and Advanced Metering Fact Sheet” (2002)

<sup>16</sup> Paul Joskow, professor of economics at MIT and director of MIT’s Center for Energy and Environmental Policy Research, as quoted in Burr, Michael, “For Real This Time,” Public Utility Fortnightly, September 2006, page 70.

<sup>17</sup> Government Accountability Office, Electricity Markets: Consumers Could Benefit from Demand Programs, but Challenges Remain, Report GAO-04-844 (August 2004).

<sup>18</sup> FERC, Demand Response and Advanced Metering (2006)

<sup>19</sup> See, e.g.,

R. J. Shapiro, N. D. Pham, *An Analysis of Spot and Futures Prices for Natural Gas: The Roles of Economic Fundamentals, Market Structure, Speculation, and Manipulation*, Sonecon (August 2006) (“Rather, high natural gas prices of the last five years and current prices for natural gas futures likely reflect other factors, including the structure of the market, speculation not based on market fundamentals and perhaps price manipulation.”)

D. Kovenock, E. Dechenaux, *Tacit Collusion and Capacity Withholding in Repeated Uniform Price Auctions*, Purdue (2004) available at <http://scholar.google.com/url?sa=U&q=http://www.iui.se/wp/wp636/IUIWP636.pdf>.

K. Rose, K. Meeusen, *2006 Performance Review of electric Power Markets – Review conducted for the Virginia State Corporation Commission* (August 2006) (“Electric market characteristics suggest that the market structure is not a robustly competitive one, as was hoped when restructuring began. Because of high supplier market concentration, the difficulty of entry from other firms to build new generation, limited entry from outside the area due to transmission access constraints, and existing market rules, the structure that is emerging more closely resembles that of an oligopoly, where there are only a few firms supplying all or most of the output, than a truly competitive market. There is also an inelastic demand for electricity, particularly in the short-run, since customers have few practical substitutes. All these factors suggest the possibility that market conditions permit suppliers to exercise significant market power.”)

---

T.D. Mount, W.D. Schulze, R.J. Thomas, R.D. Zimmerman, “*Testing the Performance of Uniform Price and Discriminative Auctions*,” Cornell University Dept. of Applied Economics and Management and Dept. of Electrical and Computer Engineering (July 16, 2001), available at <http://www.pulp.tc/uniformprice.pdf>.

This skepticism for the ability of markets to fall victim to manipulation was also recently described in the courts. In the litigation addressing the melt down of the California energy markets in 2000 and 2001, the Ninth Circuit described in detail the design of the California energy and transmission trading mechanisms in that period. It concluded its description by saying:

As we now know, something happened on the way to the trading forum, and the best laid regulatory plans went astray. The plan to establish a competitive market, while keeping the exercise of monopoly and monopsony power in check, failed to account for energy economics and the sophistication of modern energy trading. As became clear in hindsight, even those who controlled a relatively small percentage of the market had sufficient market power to skew markets artificially. In short, the old assumptions, based on antitrust theory, that market power could not be exercised by those who possessed less than 20% of the market share proved inaccurate in California’s energy market.

*California PUC v. FERC*, \_\_\_ F.3d \_\_\_, slip op. at 8785 – 8786 (9th Cir. Aug. 2, 2006).

<sup>20</sup> California Energy Commission, Feasibility of Implementing Dynamic Pricing in California: Report to the Legislature, Report 400-03-020F, October 2003, page 4.

<sup>21</sup> Charles River Associates, Impact Evaluation of the California Statewide Pricing Pilot: Final Report (March 16, 2005).

<sup>22</sup> At the height of the energy crisis in 2002, California enacted AB1-X which restricted the ability of the PUC to raise rates for residential customers until the power that was procured by the Department of Water Resources on behalf of all California’s electric customers has been paid off, estimated to be 2011. As a result, it is widely assumed that the PUC can not institute mandatory dynamic pricing programs with rates higher than those in effect for residential customers. All the California electric utilities offer residential customers voluntary TOU rate options.

<sup>23</sup> Charles River Associates, Impact Evaluation of SPP, at 75.

<sup>24</sup> California PUC, Application of PG&E for Authority to Increase Revenue Requirements to Recover the Costs to Deploy an Advanced Metering Infrastructure, Final Opinion Authorizing PG&E to Deploy Advanced Metering Infrastructure, Application 05-06-028 (July 20, 2006).

<sup>25</sup> Evaluation of the 2005 Energy-Smart Pricing Plan (August 1, 2006). This report and other valuable information about this project is available on the Community Energy Cooperative website: [www.energycooperative.org](http://www.energycooperative.org)

---

<sup>26</sup> According to the Energy Cooperative, customers were not required to disclose their income status to participate in the project, but since some of the participating customers resided in neighborhoods that were assumed to be “low-income”, those customers were viewed as representing that sub-group of residential customers.

<sup>27</sup> Star, Anthony, “Real Time Pricing is the Real Deal”, a presentation made at the Mid-Atlantic Demand Response Initiative meeting on September 16, 2006. Available at <http://www.energetics.com/madri/>.

<sup>28</sup> Recent press reports have confirmed that the actual monthly bills for many Ameren customers have increased over 100% because of the combination of the generation price increase and the termination of historical rate discounts for those who installed electric heat, both of which were implemented on January 1, 2007.

<sup>29</sup> Public Act 094-0977, effective July 30, 2006, amending the Illinois Public Utility Law, 220 ILCS 5/16-101A, 16-102, and 16-107.

<sup>30</sup> ComEd’s tariffs for the Basic Electric Service-Hourly Energy Pricing program are available on its website: [http://www.exeloncorp.com/ourcompanies/comed/comedres/energy\\_rates/our\\_rates\\_and\\_prices.htm](http://www.exeloncorp.com/ourcompanies/comed/comedres/energy_rates/our_rates_and_prices.htm).

<sup>31</sup> Illinois Commerce Commission, Docket No. 06-0617. See also subsection 16-107(b-25) of the Public Utilities Act.

<sup>32</sup> A. Faruqui and S. George, “Demise of PSE’s TOU program imparts lessons,” Electric Light & Power (Jan. 2003),

[http://uaelp.pennnet.com/articles/article\\_display.cfm?Section=ARCHI&C=Feat&ARTICLE\\_ID=165800&KEYWORDS=faruqui&p=34](http://uaelp.pennnet.com/articles/article_display.cfm?Section=ARCHI&C=Feat&ARTICLE_ID=165800&KEYWORDS=faruqui&p=34).

<sup>33</sup> This differential would have been much higher if the actual meters had been replaced with more advanced meters.

<sup>34</sup> Maine PUC, Docket No. 96-715 (October 15, 1997).

<sup>35</sup> Docket No. EO04060395, August 24, 2004.

<sup>36</sup> Docket No. EO04050395, April 27, 2006.

<sup>37</sup> With the new generation supply prices that are effective June 2007, the average price for residential generation supply portion of the bill has risen 61% since 2005.

<sup>38</sup> District of Columbia Public Service Commission, Formal Case No. 1002, Order No. 14045, September 11, 2006.

---

<sup>39</sup> Public Service Commission of the District of Columbia, “Commission Approves a Residential Smart Meter Pilot Program,” News Release, January 12, 2007.

<sup>40</sup> Public Service Commission of the District of Columbia, Formal Case No. 1002, Order No. 14166, January 12, 2007.

<sup>41</sup> Gulf Power’s website contains newsletters, fact sheets, and advertising materials relating to the Good Sense Select program: [www.southernco.com/gulfpower](http://www.southernco.com/gulfpower)

<sup>42</sup> An Act Concerning Energy Independence (Public Act No. 05-01), adopted in July 2005.

<sup>43</sup> Connecticut DPUC, Application of the Connecticut Light and Power Co. to Implement Time of Use, Interruptible or Load Response, and Seasonal Rates, Docket No. 05-10-03, Decision, December 2, 2006. The decisions with respect to commercial and industrial customer rate design are not addressed in this paper.

<sup>44</sup> *Ibid.*, at 20.

<sup>45</sup> Texas PUC, Project 31418, Rulemaking Related to Advanced Metering, Proposal for Publication issued October 26, 2006.

<sup>46</sup> Texas PUC, Report on Advanced Electric Metering as Required by HB 2129 to the 80<sup>th</sup> Texas Legislature, September 2006.

<sup>47</sup> Initial Comments of Texas Legal Services Center and Texas ROSE, Rulemaking Relating to Advanced Metering, December 18, 2006.

<sup>48</sup> Massachusetts DTE, Petition by the Massachusetts Division of Energy Resources for an Investigation into Dynamic Pricing for Basic/Default Service, Case No. 06-101, Notice of Filing and Request for Comment, November 7, 2006. The DOER petition is a 46-page document filed October 31, 2006, and available on the DTE’s website under this case number: <http://www.mass.gov/dte>

<sup>49</sup> RESA’s comments agreed with the proposal of several parties that the DTE should first focus on implementing dynamic pricing for larger commercial and industrial customers and that the investigation of such proposals for residential and small commercial customers proceed separately in a later phase.

---

<sup>50</sup> Comments of the Low Income Weatherization and Fuel Assistance Network, D.T.E. 06-101, November 30, 2006.

<sup>51</sup> See, e.g., Case 00- E-1463, *Petition of Multiple Intervenors and Deferiet Paper Company for a Declaratory Ruling that the Minimum Price for Individually Negotiated Electricity Contracts Entered into by Niagara Mohawk Power Corporation Should be Calculated on an Annual Basis, Feb. 16 2001*. ("Their request derives in part from the changed circumstances in the electricity market prices which are now not only higher but, as the marginal cost is now calculated based on the NYISO wholesale prices rather than avoided cost estimates, also considerably more volatile." *Id.*, at 7; Case 01-E-1628, *In the Matter of Electric Service at a Potential Manufacturing Facility to be Constructed in New York by Corning Incorporated, Order on Flex Rate Contract Negotiations* (Issued October 31, 2001); Case 01-E-0680, *Nucor Steel Auburn, Inc., Complaint Seeking Resolution of a Dispute With NYSEG Regarding Application of Tariff Rates*.

<sup>52</sup> Goldman, et al., *Does Real-Time Pricing Deliver Demand Response? A Case Study of Niagara Mohawk's Large Customer RTP Tariff*, Lawrence Berkeley National Laboratory (Aug. 2004) available at <http://drcc.lbl.gov/pubs/54974.pdf> .

<sup>53</sup> New York Public Service Law §66(27). This revision to the law deleted a prior provision that allowed the commission to mandate TOU rates for residential customers.

<sup>54</sup> New York PSC, Proceeding on Motion of the Commission Concerning the Availability of Time of Use Rates for Residential Customers, Order, Case No. 97-E-1795 (October 20, 1997), 1997 N.Y. PUC LEXIS 646.

<sup>55</sup> Indiana Utility Regulatory Commission, Investigation of the IURC, Pursuant to Section 1252 of the Energy Policy Act of 2005, to Commence its Consideration as to Whether it is Appropriate for Electric Utilities in the State to Provide and Install Meters and Communication Devices to Allow for Customer Participation in Time-Based pricing and other Demand Response Programs, Cause No. 43083, Prehearing Conference Order, November 21, 2006.

<sup>56</sup> Rose, Kenneth and Meeusen, Karl, Reference Manual and Procedures for Implementation of the "PURPA Standards" in the Energy Policy Act of 2005, March 22, 2006 (Sponsored by American Public Power Assoc., Edison Electric Institute, NARUC, and the National Rural Electric Cooperative Association). The Manual is available on NARUC's website: [www.naruc.org](http://www.naruc.org)

<sup>57</sup> Harris, Daniel and Bobker, Michael, "The Future of Energy Management," Home Energy, May/June 2006 (Vol. 23.3), at 24-28. More information about the Association for Energy Affordability is available at [www.aeanyc.org](http://www.aeanyc.org) .