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Responding to EPAct 2005: Looking at Smart Meters for Electricity, Time-Based Rate Structures, and Net Metering

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I. INTRODUCTION

EPACT 2005 STANDARDS ADDRESSED IN THIS PAPER

The Energy Policy Act of 2005 (EPAct 2005) renews and expands the federal government's practice of requiring that state regulators consider the case for the adoption of certain ratemaking standards. Specifically, EPAct 2005 has added five new standards to the 10 standards outlined previously in the Public Utility Regulatory Policies Act of 1978 (PURPA of 1978) and the Energy Policy Act of 1992 (EPAct of 1992).[1] These standards are added to Section 111(d) of PURPA, and address net metering, dependence on fuel sources, fossil fuel generation efficiency, time-based metering and communications, and interconnection.

The purpose of this paper is to provide guidance to state regulators on whether to adopt some or all of those proposed standards that have to do with "time-based"[2] rate design and "net metering"[3] issues. For state regulators, these are familiar issues. Two "Yogi-isms"[4] leap to mind:

- *It's deja vu all over again.* PURPA of 1978 required state regulators to consider ratemaking standards having to do with time-of-use (TOU) rates, seasonal rates, and interruptible rates—so the EPAct 2005 standards replow well-tilled ground. But, given the evolution of the industry, market structures, and metering and communications technology since that time, it may be time to revisit these issues.
- *It ain't over 'til it's over.* The states have an obligation to take a fresh look at the EPAct 2005 standards during the next few years. This is an important task because of the potential benefits that better electricity pricing can provide for customers as a whole.

A fresh look is timely because customers, and the utilities and/or generators that serve them, are again facing high energy prices. After two decades of declining prices in real terms,[5] energy supplies are once again costly and valuable. From the standpoint of efficient pricing of utility services, the necessary response to this shift in economic conditions has two key elements. First, on the supply-side, utilities must, as always, have incentives to choose the least costly basket of inputs (fuel, capital, labor, etc.) to meet their service

[1] PURPA of 1978 had six standards for state regulators to consider: (1) cost of service; (2) declining block rates; (3) time-of-day rates; (4) seasonal rates; (5) interruptible rates; and (6) load management techniques. EPAct of1992 had four standards for them to consider: (1) integrated resource planning; (2) investments in conservation and demand management; (3) energy efficiency investments in power generation and supply; and (4) consideration of the effects of wholesale power purchases on utility cost of capital.

[2] By "time-based" rate designs, we mean that the cost of electricity can vary based on time-of-day, weekday/weekend, summer/winter, etc.

[3] Net metering is also known as "net billing." In this report, the terminology aims to track closely with the terms used in EPAct 2005.

[4] Many of Yogi Berra's sayings are available on the internet at: http://www.yogiberra.com/yogi-isms.html (accessed February 18, 2006).

[5] The average real retail price of electricity has declined to 6.99 cents/kWh in 2004 from the 9.7 cents/kWh peak price set in 1983. This represents a 28 percent overall decrease, or an average decrease of about 1.5 percent per year. *Source*: Energy Information Agency, Annual Energy Review 2004, Report No. DOE/EIA-0384(2004), August 15, 2005, Table 8.10. Available on the internet at: http://www.eia.doe.gov/emeu/aer/elect.html (Accessed March 20, 2006).

obligation. Second, on the demand-side, customers must have the proper incentives if they are to respond to time-based changes in energy costs and use energy according to its real cost of generation, transmission, distribution, and sale. Thus, the serious issues that state regulators addressed following passage of PURPA of 1978 may need to be revisited.

Regulators have been directed to take a fresh look at a number of issues, including a wide variety of time-based rate structures, as well as alternative rate forms such as interruptible rates, standby or backup rates, and net metering. This review seems timely because there is some evidence that the cost of deploying "smart" meters may have declined substantially in recent years. There have been truly enormous changes in communications technology, including but not limited to wireless communications, which could potentially accommodate substantially more sophisticated pricing capabilities, such as transmitting real time price information directly to customers. Such technologies make deployment of smart meters both more feasible and potentially beneficial.

Time-based rate structures charge utility customers different prices for consumption at different times of the day, based on differing underlying costs. Time-based rate structures can improve the accuracy of the price signals that customers face during any time interval, thereby giving customers an incentive to reduce their electricity usage during high-cost periods, and to increase it in low-cost periods. When prices reflect short-run marginal costs, such shifts in market behavior can increase the overall efficiency of the electric system on both the demand and the supply sides. The net benefits to society from these efficiency improvements include: (1) the consequences of the change in the utility's investment decisions and the corresponding reduction in operating costs; and (2) the changes in the purchasing behavior of consumers. Correct price signals benefit customers and society.

This paper offers guidance to state regulators who must consider the case for the adoption of smart meters, which can allow the introduction and/or expansion of a variety of time-based rates. Smart meters can also provide other benefits to utilities and customers. For example, smart metering can enhance utilities' ability to monitor system conditions to immediately identify service outages. But the focus of this paper is on ratemaking issues. Questions that will need to be considered in responding to the 2005 revisions to PURPA's requirements are first outlined. Then, the economic principles for introducing such rates are explained. Next is a discussion of the specific standards that the states are to consider pursuant to PURPA, the types of time-based rate designs that must be considered, and the implications of "net metering" policies. Also, the cost and benefits of deploying smart meters are surveyed. In the concluding section, there is an evaluation of the potential benefits and costs of time-based rate designs and net metering from an economic perspective.

II. POLICY QUESTIONS RAISED BY ADVANCED METERING AND MORE FINELY TIME-DIFFERENTIATED RATE DESIGNS

Customers make usage decisions with high regard to the prices they face.[6] In the case of electric utility service, while there is normally only one provider of utility delivery services available, customers do have both short-and long-term choices to make regarding the actual consumption of electricity. In the short-term, the choices for a residential customer may boil down to a decision to always turn the lights off when they leave the house. But, over longer time spans, many additional choices are available. In response to a long-term price increase in the cost of energy, for example, the customer might reduce future electricity usage by buying a more efficient appliance when an old appliance needs to be replaced.

With time-differentiated rates, some activities (perhaps hot water heating) could be shifted, at least in part, to lower cost periods. Similarly, a utility customer could decide to move to a smaller or better insulated facility. Even greater opportunities for such responses are likely to exist in some portions of the commercial and industrial sectors (where companies have flexibility to alter their usage patterns). For example, a paper mill might grind pulp wood at low off-peak rates into a storage silo, and thereby still be able to operate the rest of the facility continuously, as required by technological considerations.

Utility rate design has a role to play in guiding these—and many other—consumption decisions on an efficient path. These issues are important given that:

- Customers benefit from generation and transmission (reduced losses and congestion) cost savings when load is shifted to off-peak periods. Accurately reflecting the realities of energy costs in pricing can help to reduce the overall cost of generating and delivering electricity to serve customers. Reduced usage can help to ease pressure on the network at peak times and, at times of extreme demand, this could reduce or prevent network stresses and involuntary customer interruptions. This benefits utility customers and society generally.
- Rate structures that provide price signals to encourage load-shifting improve the utilization of the electric system. Customers who shift their loads should save money for doing so.
- Reducing the internal cross-subsidies inherent in prices that are highly averaged over broad periods would be more equitable as well as more efficient. This is consistent with the principle that consumers of electricity should pay for the costs that they cause.
- More efficient pricing can help to moderate price movements in wholesale markets by providing a price response that leads to reduced usage during system peak periods. If system peaks can be reduced, the need for new generation resources (whether supply-side or demand-side) can be reduced

[6] At the convenience store, a customer may happily buy a bottle of Snapple if the price is $1.09, but might pass it up if the price is $1.59. Price is an important determinant of whether a product is purchased. Other products—such as automobile insurance—are consumed on an ongoing basis; a customer will make ongoing payments for the service, but may, occasionally, revisit the question of whether to seek a new provider, or otherwise alter his or her consumption pattern based on price considerations. For electricity, both of these types of “price discovery” considerations are relevant.

as well. Efficient pricing could help the development of the electricity marketplace by reducing hard to plan for, or politically problematic, price volatility.

Price signals provided by time-based pricing can lead to reduced electricity use during peak periods when electricity is expensive, and increased use during off peak times when it is cheaper—thereby lowering costs for all. TOU pricing is more practicable today than it was in 1978 when PURPA was enacted.

A. Policy Issues That a Commission Needs to Consider Regarding Time-Based Rate Designs

While many utilities increased the use of time-differentiated rates in the early-1980s, following PURPA of 1978, many of those rate design innovations have not persisted to the present day or are utilized only to a limited degree.[7] Time-based rate designs, if they are to be used, must both provide price signals to customers that lead to better consumption decisions and be acceptable to customers as a whole. This should not mean, of course, that any subset of customers should have a veto over rate structure modifications.

Regulators need to consider a number of questions, such as:

- **Are the existing rates sending the right price signals to customers? If not, in what ways, and to what extent, do they diverge?**

  The economic efficiency argument is that rate structures should be cost-based. The basic point here is that prices should be allocatively efficient, meaning that customers should face price signals that lead them to use resources wisely. From an efficiency standpoint, it is optimal that customers pay prices that are aligned with the marginal costs of providing that service. When prices are set based on marginal costs, customers and utilities are given crucial information about how much they should consume or produce.

- **Which form(s) of time-based rate design should be used?**

  The degree of complexity of time-based pricing systems varies widely, ranging from relatively straightforward seasonal rates, to time-of-day rates, up to real time pricing (RTP). Moreover, not every modification or refinement of rate design will be appropriate for all environments. Good rate designs will be tailored to each utility's individual circumstances. Therefore, the costs and benefits of alternative pricing approaches need to be weighed against each other with care. Residential customers may require different pricing approaches than what is required for large commercial and industrial customers.

- **What rate structure changes would be acceptable to customers?**

  Anticipating customer impact and acceptance, including an analysis of winners and losers (more colloquially, this is "the best rate structure is the old one" problem), is an important task for regulators. Simulations of the billing impacts of proposed rate structure revisions may be appropriate, so that there are no surprises. There would be little point in investing in a new generation of metering technology if the capabilities of those meters are not taken advantage of because of political pressures. Rate design changes must be made carefully, with a strong emphasis

[7] This is especially true for residential customers. Ralph Abbott explains that "the acceptance of TOU by residential consumers in the early 1980s was extremely limited." *See*: Ralph E. Abbott, "Time-of-Use Rates: Sideburns and Bellbottoms?" *Energy Markets*, July/August 2005, p. 7.

on informing customers. Rate designs must be understandable. Phasing in new rate structures may be necessary, but, if too gradual, the economics of new metering investment could change. And, to keep the process in perspective, it is important to keep in mind that in the unregulated sectors of the economy, consumers must, and do, adapt to changes in the prices they face—sometimes major ones, with price spikes in oil and gasoline markets being a good example.[8]

- **Should the time-based rate structure be optional?**

  The smart metering standard specifies that time-based rate programs shall be optional, leaving the customer to decide whether to take a time-based rate. (Of course, individual states remain free to consider other, more inclusive or mandatory, approaches as well.) This proposed feature differentiates the electricity marketplace from just about every other, where pricing options are rarely voluntary. This, in turn, may well affect (possibly to a substantial degree) the costs and/or benefits of approving some form of smart metering standard. Voluntary rate plans raise a number of issues that need to be resolved so that customers will have the correct incentives and the utility is treated fairly. These include adverse selection, possible free riders, and rate rebalancing issues, all of which are related to how a self-selecting tariff would work. After all, customers will tend to switch to the plan that they find most advantageous. In order to keep the optional rate revenue-neutral, the utility should have the opportunity to recover any lost revenues in rates.

- **Should customers that request a smart meter pay for the installation and other costs of that meter, or should the costs be socialized in rates?**

  This is not necessarily an easy question to answer. Customers should generally pay for whatever costs that they cause, such as the cost of installing a meter. But, adoption of smart metering for a sufficiently large number of customers might produce benefits to other customers who do not have smart meters, to the extent that customers with smart meters shift their usage to non-peak periods, and thereby lower system costs. The question of whether the costs should be directly assigned to the customers or shared in some fashion is an important one.

- **What are the tradeoffs that should be considered when designing time-based rate designs?**

  There is a potential conflict between efficiency goals and the desire of customers for rate stability, or just low rates. The basic point of time-based rates is that they can reduce the overall cost of producing electricity, and increase the value that derives from its use. But, that message may be lost—especially in a period of rising utility bills, which are largely the result of increases in the cost of natural gas, coal, oil, and other fuels. The argument that, under the proper time-based rate structure, costs will be "lower than they would otherwise be" (but not actually lower relative to last year) can be a tough sell, even if the net benefits are substantial.

[8] In addition, high prices send signals to investors. Their entry into a market will result in innovation, increased production (as well as competition in unregulated markets) and ultimately lower commodity prices than had these investors not entered. For example, the recent rise in oil prices has resulted in a renewed interest in the potential of Canadian sand oil fields. The investment in these projects is only possible because of the price signal: "[t]he high cost of extracting oil from oil sands is no longer a major impediment to production, now that oil prices are at $60 a barrel or more and most experts expect them to remain relatively high for years." *Source*: Clifford Krauss, "Riding High on a Tide of Oil," *The New York Times*, March 28, 2006, p. C4.

- **Can we count on significant demand response when the efficient price is charged? What do we know about how responsive the different customer classes are to changes in the prices they face?**

  Here we are not confronting a relatively simple increase in the average price of the commodity. As increased time differentiation becomes available there are many new ways to optimize consumption and, as a result, more complex responses are likely. In addition, consideration of short, intermediate, and long term responses must be a part of the process. Generally, elasticity of demand (the price-responsiveness of usage decisions) grows over time, as consumers learn how to adjust to new opportunities, but regulators need to consider also the "staying power" of time-shifted activities—some TOU customers, for example, may "wear out" and lose interest in TOU after a few years.[9] This is a critical issue, as the benefits of smart metering hinge on the answer.

- **How should an interruptible rate be priced?**

  The basic principle is that the reduced rate should reflect the costs that the utility avoids (i.e., savings in peak load capacity and energy) because the utility may interrupt the customer during peak demand periods. Critical, of course, is that the resource be available when it is called upon. Historically, such issues have been highly litigious with major fights breaking out between customer classes.

- **Will interruptible capacity be reliable enough to avoid the need for costly new generation resources? How does broad reform of the pricing structure compare to older programs, such as interruptible rates?**

  One lesson of the "interruptible rate" programs of the 1980s was that a large industrial customer could benefit from being regularly served at a lower price because of the "interruptibility" feature and then be "shocked" when it was actually interrupted or when asked by the utility to reduce his load.[10] Low interruptible prices came to be viewed in some cases as "regular" or even "economic development" rates. The basic question is: will the interruptible customer curtail its load when called upon to do so?[11]

- **Are the issues the same in both restructured and traditional environments? If not, what are the key differences? What role might competitive suppliers play in fostering more sophisticated metering and rate design?**

  Time-based pricing may have slightly different implications for restructured and traditional environments. Both traditional bundled rates and restructured unbundled rates can have pricing elements that are time-based. For an unbundled utility, some demand-response activities occur at the independent system operator/regional transmission operator (ISO/RTO) level, which might have some effects on the design of some time-based rates. The time-based data is itself the critical element in these efforts. As long as the data is available to customers (and also, where appropriate, to energy marketers), the question of who installs or owns the metering should be moot.

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[9] Abbott, *supra* note 7, p. 7.

[10] In the 1942 film Casablanca, Captain Renault says to Rick, "I'm shocked, shocked to find that gambling is going on in here!" The croupier then hands him his winnings.

[11] Interruptible customers can often procure power when "interrupted," but at a market or penalty price.

- **How can time-based rate designs be implemented?**
  Educating customers and building the political case may be the last item on this list, but is perhaps the most important question to answer. As already noted, from a socio-political perspective, the best rate structure is usually the old one. (One of the authors has learned this directly, the hard way.[12])

It is incumbent on state regulators to recall that time-based pricing issues need a careful analysis not only because the revisions in PURPA require states to consider them, but because there is a strong economic policy basis for doing so. Given the socially desirable consequences of aligning rates with costs, regulators should evaluate the extent to which time-based pricing can provide customers with the proper incentives to expand or reduce usage when it is efficient to do so.

B. Policy Issues Related to Net Metering

Distributed generation (DG) is defined as small-scale generation located in close proximity to the load being served. DG can allow a utility customer to largely bypass the electric distributor. Because of its obligation to serve the customer when the DG facility is out of service, the distributor still incurs certain costs which should be recovered in either its standard rate tariffs or through rates for standby/backup service. DG resources include power producing (supply-side) technologies that are installed in a dispersed fashion throughout a utility distribution system, including at end-user locations. Efficient distributed resources are those that result in net benefits; that is, cost reductions greater than the combined costs of installation and operation of the distributed resource.

Net metering allows the electric meters of customers with generating facilities to run backwards when their generator is producing more electricity than they demand themselves.[13] Running the meter backwards, with no other adjustments, allows the DG customer to receive a credit in excess of the costs that the utility avoids as a result of receiving generation from the customer. Net metering has, in practice, generally provided a subsidy to a DG customer and imposed burdens on other customers. In effect, this is a case of the utility being required to credit the DG customer for other utility delivery costs that are not avoided, in addition to paying the generator for the power itself. This cost, of course, will eventually come out of other customers' pockets. With the use of smart meters, however, DG customer-generators can be provided with a reasonable payment for their electricity that is based on the utility's avoided costs.

When considering the implementation of net metering a commission needs to consider the following policy issues:

- **What are the state's current net metering policies?**
  For example, does the state allow the meter to run backwards when the customer-generator is a net seller of electricity? And does the state reimburse the DG customer with a retail price or an avoided wholesale price for the customer's excess generation?

[12] Dr. Gordon, while chairman of a public utility commission, endorsed what were thought to be efficiency-enhancing changes in rate structure. The reaction of those adversely affected was strong, and the Maine Public Utilities Commission had to back up in response to the outcry. Those who came out ahead offered little support—they simply laid low.

[13] This would not be necessary if two meters were used at the customer's premises, one for electricity usage and one for electricity production. Most states have typically not used this approach. Regulators have reduced the aggregate amount of the subsidy by limiting the availability of net metering in various ways, e.g., to smaller customers of the utility.

- **What costs does the utility avoid because it purchases generation from the DG generator?**
  Cost categories that need to be identified and assessed include costs of distribution, transmission, and generation. In particular, there should be an assessment of the likelihood of short-term and long-term impacts of DG on these costs.

- **Will other customers have to pick up distribution costs caused by the customer-generator?**
  Net metering customers clearly benefit from being connected to the distribution system. After all, they use the distribution system both to *sell* electricity to the utility and to *buy* electricity from the utility. Standby/backup rates are one way to deal with the situation where a utility customer that self-generates causes distribution costs but may not actually procure much electricity from the utility.

- **Is a subsidy currently being provided to DG customers?**
  This is, in effect, a question of whether costs incurred by customers to install, interconnect, and operate their generation are being "underwritten" by other customers on the utility's system, or whether costs that the customer would otherwise incur to receive service from the utility are being paid for by other customers. It should also be determined whether and to what extent net metering might allow customer-generators to avoid other costs, such as system benefit charges, transition costs, etc.

- **Can this subsidy be eliminated by correct pricing?**
  DG can result in cost shifting from DG customers to non-DG customers because most utility costs are recovered on a "throughput" basis. Economically correct net metering and economically efficient standby/backup price structures are parts of the solution to this problem. A pricing structure for net metering that delineates between the fixed-cost components of the delivery system, on the one hand, and generation costs and the short-run marginal costs of the delivery system, on the other hand, could reduce or eliminate inherent subsidies and cross-subsidies. Whether a utility could actually introduce such pricing would depend on the state's relevant public utility laws.

- **What criteria should be used to decide which customers should be eligible for net metering?**
  This is related to the scope of a net metering initiative and the possible impact on electric system operations and the utility's financial profile. Considerations include the eligibility of which customer class(es), which technologies, what sizes of on-site generation, and the size of an overall cap.

Net metering as currently practiced in many U.S. states results in price distortions that adversely affect customers who do not sell electricity to the utility. With smart metering, rational pricing policy becomes more feasible. Taking advantage of smart metering technology will be required in order to end—or at least reduce—the subsidy flows that result from current net metering practices.

C. The Business Side of the Case for Smart Meters

The basic premise of taking a fresh look at smart meters is that their installation and operating costs may well have gone down sufficiently such that the new smart meters, with greater TOU tracking and pricing capabilities, can be cost-effectively installed on the utility distribution system. The newer electronic meters provide more accurate measurement of energy use and are designed to work with automated meter reading (AMR) and advanced metering networks. Because the costs will be passed through to customers in rates, it is important to ensure that the installation of smart meters generates net benefits for customers. Smart meters can measure electricity usage by time-of-day and over desired day periods. Therefore, TOU rate designs, which provide better price signals, can be devised and implemented. With these price signals, customers would have the information necessary to decide whether to control usage during peak periods when the price is high, and when to shift their consumption to lower cost times. Over time, electric customers facing more differentiated cost-based pricing could modify their electricity usage more fundamentally, leading to lower utility costs for all.

Various forms of electronic metering have been available in the past, but because of the high costs associated with installation and data retrieval, they have not been widely utilized. With the costs of deploying smart meters now economically feasible for more customers, and the metering technology continuing to improve, it is useful to reconsider the role that smart metering may be able to play. Nevertheless, the cost of the metering and communications infrastructure remains a significant aspect of the cost-benefit analysis.[14]

When considering the implementation of smart meters, a commission needs to consider the following policy issues:

- **Is there a commitment by the regulator and the utility to use the full capabilities of the smart meter to improve price signals?**

  The costs of installing smart meters are not negligible. There are, for example, the costs of replacing the existing electromechanical meter, the likely shorter useful lives of smart meters,[15] and the need to replace meters on a "one-off" (one at a time, not a general deployment) basis. A very important precondition to any regulatory initiative to encourage the installation and use of smart meters are a credible commitment to: (1) better pricing of electric utility services; and (2) achieving the efficiencies that this brings. It would be unfortunate if utility customers were to end up worse off from an investment in smart meters.

- **What efficiency gains in the use of electricity can be achieved under existing frameworks?**

  This is a good question—and not easy to answer. Some types of time-based pricing are possible with existing meters. In some cases, utility regulators may find that it is already technically feasible to implement some time-based pricing but not yet economic to adopt new meters. Regulatory policies on the recovery of metering plant, for example, could affect the installation decision independently of the underlying economics.[16] Some states may reasonably decide that refurbishing existing metering frameworks is sufficient and that smart metering is not likely to be beneficial. Other states may decide that it is time to move away from an overly averaged rate structure by emphasizing time-based rates. The proper analytic framework is incremental, i.e., the incremental cost of smart meters weighed against the gains that can be achieved with this technology.

[14] In Ontario, the cost of "one-off" (one at a time) installations of residential meters is estimated to "cost five times more to complete" than mass deployment. Ontario Energy Board, *Smart Meter Implementation Plan: Report of the Board to the Minister*, January 26, 2005, p. 20. [Hereinafter referred to as "Ontario Smart Meter Report."]

[15] The useful expected life of electronic meters is expected to be about 10 to 15 years, due to the pace of technological innovation. The useful life of traditional meters is 25-30 years.

[16] Prudently incurred metering plant should be recovered in rates even if a decision is made that smart meters should be installed to replace that metering plant. Following this principle would remove the possible ratemaking disincentive. Similarly, prudent investments by utilities in smart metering systems that reduce meter reading costs should be recoverable in rates without the risk that regulators will subsequently deny recovery of these systems, perhaps as part of a move to competitive metering.

- **What key additional capabilities does the "new generation" of meters have?**

  This is an important question. The point of this paper—the "dog," if you will—is the economic and social benefits of time-based pricing. Smart meters are the "tail"—and we must not let the tail wag the dog. Smart meters are a means toward an end: the benefits to customers and society that time-based pricing can bring. Most existing meters are not able to record usage by narrow periods of time within a day or week. They require a meter reader to collect gross usage data from a digital (or sometimes analogue) display. Smart metering allows a utility to collect customers' hourly usage and peak-demand data for 15 minute (or potentially even shorter) intervals. It therefore allows for hourly-based and/or time-based pricing. This means that a number of more complicated time-based pricing approaches are feasible. Therefore, smart meters have the potential to offer a number of benefits to both the utility and the consumer, including better information and control of energy use, new service opportunities for companies, enhanced power network management facilities, and connection to digital services. AMR can significantly reduce business costs by replacing manual meter reading, eliminating the need to issue estimated bills and thereby significantly decreasing the cost of dealing with billing questions.

- **What are the costs of replacing existing meters, and then maintaining and operating the new ones, including any necessary communications capabilities?**

  A careful and thoughtful cost-benefit analysis is needed to support a decision about upgrading metering and communication infrastructure.[17]

- **What are the likely short- and long-run benefits of installing new meters?**

  This will require an analysis of likely demand responses to price adjustments (both up and down, and in both the short and the long runs) in a variety of circumstances. From a utility's perspective, the benefits of automatic meter reading (in terms of new sources of revenue, reduced expenses, avoided losses, and capital reductions) may go a long way to justify the deployment of smart meters.

- **Would increased use of time-based rate designs be acceptable to customers?**

  While political concerns about customer acceptability are real, the cost-benefit analysis should be the primary concern of regulators. Voluntary programs may help mitigate these problems (see previous comments and concerns on the "voluntary" issue), but the aim should remain the potential economic and social gains from time-based pricing and not appeasing the "squeaky wheel."

- **When the costs and benefits of the deployment of new meters are weighed, are there likely to be net benefits?**

  The answer to this question will vary from utility to utility and state to state and each utility's circumstances should inform a commission's decision-making process. Depending on the starting point of each jurisdiction with regard to its rate structure, system demand characteristics, status of restructuring, and many other concerns unique to the state, equivalent cost-benefit analyses may yield completely different results.

[17] *See* Steven C. Hadden (Plexus Research, Inc.) "Addressing the New PURPA Time-Based Metering Standard 111(d)(14)," presentation to the Spring 2006 Metering Track, sponsored by Siemens and EEI, April 3, 2006.

Smart metering still appears to have significant up-front costs; but a possibly even more important factor is that the benefits that the meters can provide will only be realized if regulators have the will to use the new metering capabilities. And this means implementing the cost-reflective, time-based rate designs that can lead to more efficient utilization of electricity.

III. CONSUMER BENEFITS FROM MORE EFFICIENT PRICING

Customers are, and should be, the central focus of utility regulatory policies. However, this does not mean that utility customers should not pay the correct cost-based prices for electricity—customers must face price signals that reflect all of the costs of generating, transmitting, distributing, and selling electricity. This is important to ensure that society's resources are used efficiently.

An electric utility system that serves utility customers in the most efficient, safe, adequate, and reliable manner reasonably possible is what customers require—and utility regulation can play a role in providing the incentives to make that happen. Thus, electricity ratemaking must allow the utility a reasonable opportunity to recover its prudently-incurred costs, while also signaling to customers the marginal costs of using the utility system and the electricity commodity. There is also a need to ensure that subsidies and cross-subsidies are not flowing to favored customer classes from the general body of ratepayers.

Finally, let us remember that utility regulation continues to have an oversight role in making sure that customers are provided with reliable electricity service at a just and reasonable cost. But the regulator's "thumb" must not be on the scale—regulatory policies that distort the price signals (and related requirements) that producers and customers face with regard to electricity consumption are antithetical to the concept of competitively driven markets and almost certainly will lead to an inefficient outcome. That result would be costly to electricity customers, and harmful to a state's economic competitiveness. Sadly, that was often the result in many of the states that embraced the integrated resource planning (IRP) approach a decade and a half ago.

From an economist's standpoint, the basic selling point of time-based rates is that they can send more accurate price signals to customers. Prices can be designed to be higher at peak periods, whether that is the peak period in a day, or the peak of the season, among others. In the short- and medium-term, these price signals provide incentives to customers to shift their electricity usage to low-priced periods and, symmetrically, to reduce their usage in high-price periods. In the longer term, customers have incentives to engage in energy efficiency efforts focused on high-priced periods. The following sections show how appropriately designed time-based rate structures coupled with new smart meters can improve efficiency in electricity consumption, reduce and eliminate inappropriate subsidies and cross-subsidies in current rate designs, and reduce the cost of improving system reliability.

A. Reduced Deadweight Losses from Smart Metering and Time-Based Pricing

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 a "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."[18] The benefit of smart metering is that it makes it more

[18] The problem is not a new one for regulators and economists. *See* J. Maurice Clark, "Rates for Public Utilities," *American Economic Review*, September 1911, pp. 473-487.

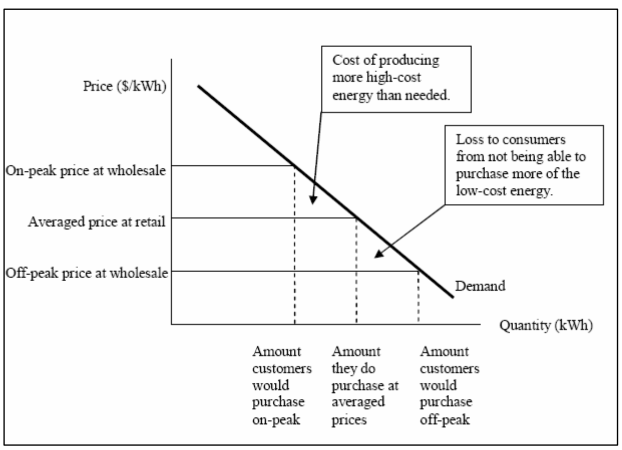
feasible to price electricity at its real cost through time. This, in turn, can lead to the elimination (or, more realistically, the reduction) of deadweight losses, thereby promoting social welfare.

There are two types of deadweight losses that result from relying on highly averaged prices instead of time-based prices. These are:

- **Deadweight losses** from charging *too high* a price in some hours. If energy consumed during off-peak hours costs less than the "averaged" retail price the customers face, consumption will be inefficiently low—customers will use less energy than they would consume under a cost-reflective tariff. Charging too high a price during off-peak periods (whether these are defined within a day, a week, a season, etc.) will mean that customers will not receive the value of the off-peak energy they did not use. Customers are likely to be better off if prices closely reflect the off-peak marginal cost during these periods.
- **Deadweight losses** from charging *too low* a price in some hours. During peak-periods, the extra costs of producing power can be sizable. Charging too low a price (below the actual marginal cost or market price) for power during peak periods will prevent customers from receiving an incentive to reduce usage in those hours, or shift loads to other periods. Consumption in peak hours will be inefficiently high, and the incremental costs incurred to produce that energy will not be recovered from the customers on this particular retail rate. Resources are used to produce kWh whose value to customers is below the cost of production.

The benefits from more cost-focused metering arise from avoiding deadweight losses of the type shown in Figure 1.[19] Such deadweight losses are being experienced today in many electricity markets as a result of highly averaged rates.[20]

Figure 1: Deadweight Losses from Retail Prices that Differ from Underlying Marginal Cost[21]



19 Sally Hunt, *Making Competition Work in Electricity* (New York: John Wiley & Sons, Inc., 2002), p. 81.

20 An example of reduced deadweight losses from better pricing might be the practice of hotels raising prices during peak demand periods but offering lower rates during off-peak periods. The consumer benefits from lower pricing during off-peak periods are obvious, but there are consumer benefits from higher on-peak prices as well, which result from efficiently allocating scarce hotel rooms to those who put the highest value on them. And, you cannot get the benefits of the lower off-peak prices without compensatory increases in on-peak prices.

21 Figure from Hunt, supra note 19, p. 81. Reprinted with permission of John Wiley & Sons, Inc. Copyright @2002 by Sally Hunt.

The rate structures faced by electricity customers in their jurisdiction may have significant inefficiencies that could be corrected with more time-specific pricing. Sally Hunt explains the core analysis that regulators must conduct with respect to the advanced metering decision: "[f]or any given situation, the value of metering depends on how distorted the averaged pricing is, on the absolute size of customers, and on how responsive their demand is."[22]

B. Reduced Cost of Utility Service over Time

Efficiency benefits of time-based metering can also come from reducing the cost of socialized reliability solutions. The lack of demand response can impose substantial costs on utility customers. If there is no demand response during periods of peak demand, more costly generating units will necessarily have to run and wholesale market prices will increase accordingly.

Absent a demand response, the cost of electricity can become painfully expensive at peak periods and/or during shortage conditions. That is why there can be real societal benefits from providing time-based price signals to customers. This is particularly the case when retail prices cannot change hourly to accommodate unexpected wholesale market price increases. Sally Hunt explains that:

> If there is no customer response, when supplies get tight there have to be involuntary curtailments, by exhortations to conserve or by rolling blackouts. […] Unless customers are able to respond to prices at the peak, through hourly metering and hourly pricing, the generators have a distinct advantage over the customers. They can bid up the peak price as high as they like unless there are customers who can say "play this hand without me."[23]

In an environment where fuel and wholesale power prices are high and vary widely across the day or season, and where new generation is needed in many parts of the country, the social costs of not implementing time-based rates would be high. This is especially true in parts of the country where building new generation is no easy matter. While it is relatively easy to explain how production (supply side) efficiencies can be gained from better pricing, consumption-side gains are harder to explain—but this consideration needs to be addressed or the analysis of smart metering will be erroneous.

C. Reduced Subsidies and Cross-Subsidies from Proper DG and Net Metering Policies

Some utility customers are also producers of electricity. DG has some potential to provide benefits, such as reduced transmission congestion, avoided fuel and purchased power costs, and possibly deferred transmission and distribution investment. However, utility customers that produce electricity should be neither subsidized nor artificially penalized, or else possible efficiency information would be masked or lost. Net metering programs were developed during the 1980s as one aspect of a multi-faceted effort by some utility regulators to pursue social goals (e.g., environmentalism) over traditional economic concerns. The effect of these programs was to provide a subsidy to those customers who were eligible for net metering service.

[22] Hunt, *supra* note 19.

[23] Hunt, *supra* note 19, p. 76.

Net metering customers historically have not paid the correct prices for buying and selling electricity from a utility. Simple-minded approaches such as running the meter backwards provide a subsidy payment that forms a "wedge" between the price that DG utility customers pay and the cost incurred by the utility.[24] Smart meters can accommodate correct pricing, thereby eliminating the subsidy flow to net metering customers.

Net metering as introduced and practiced in the 1980s jumbles together three separate transactions between the net metering customers. These are:

- *Sale of electricity to the utility*. The utility should pay the net metering customer a price for electricity that reflects the cost that the utility *avoids* paying as a result of procuring electricity from net metering customers. Running the meter backward, however, allows the net metering customer to avoid *all* of the utility charges. The utility can avoid only the marginal costs of generating and transmitting the power produced by the DG, but cannot avoid fixed costs of serving the DG customer-generator. This subsidy flow is not justified.
- *Payment for utility delivery services*. The net metering customer is benefiting from access to the delivery system both to sell power to the utility when its generation is on-line and to buy power from the utility when its generation is off-line. By any stretch of the imagination, there is no justification for allowing the net metering customer to avoid paying the delivery costs portion of the utility bill when it is using that system to sell power to the utility.
- *Purchase of electricity from the utility*. The utility should be able to recover its costs of procuring and distributing power (including capacity) for the customer.

Net metering with a smart meter can price each of these transactions properly, thus eliminating the subsidy flow. There is no economic reason not to do this. By improving the utility's ability to differentiate between electricity consumed and electricity produced, as well as improving the measurement of the time of day at which the electricity is consumed or produced, smart meters allow DG customer-generators to be provided with a reasonable payment for their electricity that is based on the utility's actual avoided costs and prevent cross-subsidization of DG by the utility's other customers.[25]

[24] The problem for the utility is that it may not be able to avoid many of its costs even if the customer self- generates its entire load. If there is a continuing obligation to serve, and if the customer's generator goes off-line on the hottest day of the year, the customer can demand service from the utility. To perform this function, back-up distribution, transmission, and generating capacity must be maintained—even though the customer appears to not be fully utilizing them. Where most utility costs are recovered in usage charges (i.e., on a throughput basis), costs the utility bears as a result of providing service to a customer-generator can be shifted to non-DG customers. The DG customer simply doesn't buy enough electricity to pick up its share of utility fixed costs.

[25] As a practical response to the above issues, state regulators have, in the past, imposed limits on the size of net metering programs and/or limited which type of DG could receive the benefits of net metering.

IV. THE SMART METERING STANDARD (PURPA §111(D)(14)) AND TIME-BASED RATE STRUCTURES

EPAct 2005 establishes, in PURPA §132(f), that it is the policy of the U.S. that "time-based pricing and other forms of demand response … shall be encouraged." But, EPAct 2005 recognizes that it is largely up to the states to decide whether and how to implement this policy.

State regulators must consider whether to adopt the smart metering standard.[26] After reviewing the tasks EPAct gives to the states, consideration will be given to the basic case for smart meters and time-based rate schedules. Following that is a discussion of some of the more detailed rate design issues that must be considered by state regulators.

A. Tasks for State Regulators

The smart metering section generally requires that state regulators begin a proceeding to consider whether or not to adopt PURPA §111(d)'s "standard" within one year of enactment; state regulators must reach a decision within two years of enactment.[27] The standard that the states are to consider is as follows:

> (14) TIME-BASED METERING AND COMMUNICATIONS.—(A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customer classes, and provide individual customers upon customer 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 rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

PURPA §111(d)(14)(C) goes on to explain that "[e]ach electric utility subject to subparagraph (A) shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate, respectively."

EPAct 2005 also establishes at PURPA §115(i) an "investigation requirement" that states that:

> Each State regulatory authority shall conduct an investigation and issue a decision whether or not it is appropriate for electric utilities to provide and install time-based meters and communications devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs.

[26] *See*: Kenneth Rose and Karl Meeusen, Reference Manual and Procedures For Implementation Of the "PURPA Standards" in the Energy Policy Act of 2005, March 22, 2006. Available on the internet at: http://www.nwppa.org/web/presentations/PP_Fourm_3-06/PURPA%20Manual.pdf (accessed on April 10, 2006).

[27] There are some certain exceptions for states that have already adopted or recently considered a similar standard.

If a state regulator decides to implement the smart metering standard, electric utilities in the state would need to modify their tariff schedules to comply with the time-based rate schedule requirements and receive regulatory approval of those tariffs.[28]

B. The Types of Time-Based Rate Schedules That Need to be Examined

The smart metering section at PURPA §111(d)(14)(B) specifically identifies several types of time-based rate schedules. These include what can be called traditional TOU pricing as well as (1) critical peak pricing (CPP), (2) real-time pricing (RTP), and (3) credits for customers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.

1. Traditional Time-of-Use Pricing

Traditional TOU rates include kWh charges that typically vary by season and time-of-day.[29] PURPA §111(d)(14)(B)(i) defines traditional TOU as:

> [E]lectricity prices … set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall.

These rates typically have intra-day rating periods (defined as blocks of hours) during which hourly costs are fairly homogeneous. Those periods can also change seasonally if warranted by marginal cost changes across the seasons. TOU rates offer the potential to give better signals to customers about the cost consequences of their electricity consumption decisions, as compared to rates with flat energy charges. TOU rates have historically been limited primarily to higher-usage customers; such rates are uncommon for residential customers except on an optional basis.

Inverted block rates are one way to implement TOU rates. Using energy blocks may be useful when the revenue requirement is substantially above or below marginal cost revenues, and the difference cannot be fully allocated to fixed charges. Block rates should ideally preserve the efficiency of the price signal for marginal use (the tail block). Inverted block rates combined with TOU periods can provide efficient price signals if the "run-off" rate for the tail-block is set at or close to marginal cost, and the first block is set uniformly for all customers within the class to recover the remaining revenue requirement. Choosing the block size is thus a critical task in the design of inverted block rates because: (1) the larger the first block, the fewer the customers who will see and respond to the more efficient tail-block price; (2) the smaller the first block, the more revenue that will be collected from energy priced at marginal cost, and the lower (and less efficient) the first-block price will need to be.

[28] The wording of the standard, if adopted as proposed, would require utilities to offer time-based rates within 18 months. One way to interpret this is that the regulatory commissions are provided a full 24 months to make a determination as to whether to adopt such a standard. Then, state regulators would have 18 months to investigate and implement time-based rate tariffs.

[29] Some forms of traditional TOU rates do not necessarily require smart metering.

Time-based rate structures are typically proposed for one or more of the following reasons:

- *Improve economic efficiency* by pricing electricity so that customers face prices for marginal consumption that approximate the marginal costs of service.
- *Promote cost-effective conservation*, thus reducing the need for conservation subsidies.
- *Encourage load shifting and load growth during off-peak periods*.
- *Improve inter- and intra-class rate equity* by eliminating cross-subsidies (which can lead to uneconomic bypass and lost profits).
- *Increase customer choice* by giving customers flexibility in the way they manage their energy costs.

To serve the intended efficiency goals, TOU rates need to reflect as closely as possible the underlying short-run marginal costs of service—the incremental cost of serving one more unit of load. If the price they face for altering those decisions reflects their underlying economic cost, customers will make efficient decisions about business location, choice of appliances and equipment, and use of electrical equipment. Estimates of time-based generation, transmission, and higher voltage distribution marginal costs provide the basis for establishing efficient price differentials among seasons and daily pricing periods in TOU rates, as well as efficient tail-block rates for inverted-block rate structures. Hourly marginal generation cost estimates are typically derived from the expected market prices for energy and capacity of the region where a utility is located. Market prices represent the utility's opportunity cost of supplying an additional unit of demand. An increment of load in a particular hour may also increase losses and congestion costs, which may trigger transmission (and maybe distribution) capacity expansion. Therefore, time-based marginal transmission costs require estimates of the *hourly* marginal energy losses and hourly congestion costs necessary to accommodate an increase in load.[30]

Adverse selection is a problem if the TOU rates are voluntary. Voluntary TOU programs will only attract those customers for whom the TOU is beneficial. Customers who would be harmed by TOU rates will remain on the traditional rates. If all customers were to participate, then the customers who would pay the higher on-peak rate would balance those receiving the off-peak rate. Because the utility knows this, they will be forced to reduce the size of the incentive structure (low off-peak prices vs. high on-peak prices) relative to a mandatory TOU program.

Adverse selection is the result of asymmetric information: the utility cannot readily identify each customer's load flexibility or how they would individually respond to TOU rates. A utility may reduce this asymmetry by designing a TOU rate so that only large customers apply, but if PURPA §111(d)(14)(B) is adopted by a state, TOU rates would be offered to all customer classes. As a result, utilities may need to rebalance existing rates to compensate for any revenue erosion resulting from the expected rate migration (plus any additional adjustments later in the process if rate migration does not occur as anticipated). Making TOU rates the default rates for all customer classes would avoid this. However, a cost-effectiveness study would first need to be undertaken and the customer acceptance issues would need to be considered carefully.

[30] In nodal markets operated by ISOs/RTOs, this marginal cost information is immediately available via locational market prices (LMPs). In non-restructured systems where a vertically-integrated utility plans and controls its own network, estimates of marginal transmission costs may be derived from the utility's typical growth-related transmission investment per unit of peak load growth, and time-differentiated based on each hour's probability of being the system peak.

A tariff rebalancing exercise to eliminate or reduce existing cross-subsidies among customer classes would be a very constructive precondition to adoption of effective time-based rates/smart metering.[31] Cross-subsidies affect both the efficiency and the equity of electricity tariffs. From an efficiency point of view, cross-subsidies should be defined with regard to marginal costs. If a set of tariffs results in a class of customers paying less than its *efficient* share of the revenue requirement—i.e., defined as the class marginal cost revenues plus an efficient allocation of the overall marginal cost revenue gap—these customers are receiving a cross-subsidy. As a result, they may not find an efficient, optional TOU rate that reflects time-based marginal costs attractive if it leads to an increase in their energy bills, even if that increase is justified on the basis of cost. When the link between what the customer pays in the existing rate and the costs he imposes on the system is broken, optional TOU rates are only attractive to customers to the extent they maintain the existing subsidies to the class. If the difference between the tariff these customers pay and the marginal costs is made up by charging prices higher than marginal cost to other customers, the inefficiency losses increase—the over-charged customers are discouraged from using electricity that would cost less to supply than its value to these customers.[32]

2. Critical Peak Pricing

Critical peak pricing takes TOU rates another step to include a dynamic component that can more closely track costs under extreme peak conditions.[33] CPP is used to raise tariff charges significantly to alert electricity customers during "critical peak" periods of energy usage, such as the summer air-conditioning season. CPP can provide benefits in terms of reduced peak power usage, which may reduce transmission congestion and the burden on the distribution system during peak periods.

CPP is essentially an alternative way to set up an interruptible rate. PURPA §111(d)(14)(B)(ii) defines CPP as when:

> [T]ime-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption.

The goal of CPP is to improve consumer response to unpredictable spikes in energy usage during peak demand periods. CPP can be just the same as TOU rates for perhaps 95 percent of the year, but CPP increases the price of electricity significantly on critical peak days. In return for requiring customers to pay the higher critical peak rates, the rates for non-critical periods are lowered.

To implement CPP, participants must install a smart meter. CPP programs require interval data recorder meters with related telecommunications capability that allows the utility to notify customers when the dynamic peak period is in effect and to retrieve the hourly consumption data during that period. Accordingly, CPP efforts have to date been focused primarily on commercial and industrial customers.

Under this rate structure, prices for normal TOU periods as well as "critical peak" periods are defined in the rates, along with a definition of the conditions that justify declaration of a "critical peak." There are a limited

[31] Although major shifts of revenue requirements among classes are difficult (except in the case of an overall rate decrease), there may be opportunities for a gradual shift, based on an appropriate definition of "cost of service."

[32] Cross-subsidies can also lead to unnecessary investment in network and generation capacity, as subsidized customers expand their consumption past the efficient level, leaving more costs to be shouldered by the subsidizing classes.

[33] A CPP component could be added to traditional rates that do not have TOU features.

number of these critical-peak periods per year (in California, no more than 12 per summer, but this is an arbitrary cap that could be relaxed). Typically these critical periods can be triggered when objective criteria are met, such as high temperatures, high energy usage, high wholesale market prices, or emergencies.[34] The critical peak price is only charged in hours when an alert has been called. Users receive an alert shortly before the critical period starts in order to allow them to control their consumption and manage price risk.

CPP prices should be set based on short-term costs. In principle, where transparent wholesale prices are available, it could be argued that the critical period CPP prices could be set to reflect cost conditions in the wholesale power market. Alternatively, the CPP prices could be set based on cost conditions during comparable time periods. The non-critical period charges should be set such that they are equivalent to the traditional TOU rate *except that* the customer should receive a credit that is equal to the costs that the utility *avoids* because the customer reduces its energy usage during critical periods. The California Public Utilities Commission (CPUC) Decision on CPP rates specifies that a separate revenue requirement component, based on the incremental costs incurred during a critical event, should be specified.[35] This new revenue requirement would be allocated exclusively to the critical peak period.[36]

The critical peak per-kWh charge reflects the cost that the utility incurs if the customer does not reduce his consumption. If CPP rates were mandatory, there would be no need for an explicit credit in the non-critical periods. A customer lowering his demand in the critical period would immediately get a credit equal to the avoided cost. However, CPP rates are expected to be offered to customers on a voluntary basis. Absent this credit, a customer moving to a CPP rate would only face an upside risk. This would mean that customers whose load contributes significantly to peak demand levels would be highly unlikely to have incentives or interest in participating. If the CPP rate is set to give CPP customers access to lower prices during the non-critical periods as compared to other rates, then it is reasonable to penalize customers who do not abide by their commitments. In practice, the prices charged to CPP customers who fail to reduce load during the critical periods are substantial—up to 14 times the normal summer on-peak rate.[37]

Since rate charges at all other times are lower than comparable prices on other rates, users can save if they curtail load during CPP periods or switch their load to non-CPP periods; but, they should not receive rate reductions during non-critical periods that are not cost justified. Southern California Edison's CPP customers, for example, are charged a cost-justified demand charge that is about 80 percent less than the normal summer mid-peak demand charge and about 60 percent less than the normal on-peak demand charge.[38] Consistent with the CA CPP Decision, these lower charges are determined with a revenue

[34] *See* Southern California Edison, "Information on SCE's Critical Peak Pricing (CPP) Rate Options," July 2005. [Hereinafter, "SCE FAQ."] Available on the internet at: http://www.sce.com/NR/rdonlyres/FAEC5FA4-A21D-4394-BB94-609032F010AE/0/CPPQAJuly2005_.pdf (accessed on February 28, 2006).

[35] Before the Public Utility Commission of the State of California, "Opinion Addressing Critical Peak Pricing for Customers 200 Kilowatts and Larger." Applications 05-01-016, 05-01-017, and 05-01-018, April 22, 2005. [Hereinafter, the "CA CPP Decision."] The CA CPP Decision established that, for customers larger than 200 kW, the utilities had to file revenue-neutral plans for CPP programs. They were originally planned to be implemented in the summer of 2005. However, customers complained that they did not have time to prepare, and the program has been deferred until the summer of 2006. The PUC wanted narrower peak periods with a higher price, or pre-established periods rather than event-triggered periods. Customers said that if high prices are predictable, they can justify investment in the equipment necessary to respond to them. A peak period of 2-6 pm was also mandated. The CPP rates will be the default rates, but customers can opt to keep their current rates. Therefore, they are essentially voluntary rates.

[36] Id., pp. 44-45.

[37] SCE FAQ, s*upra* note 34.

[38] Id.

requirement that assumes no critical events.[39] The CPP "high" rate should reflect the revenue requirement of providing power during the critical periods, but the CPP "low" rate should be cost justified with the revenue requirement for providing service at all other times of the year. The CA CPP Order explains that:

> In order to send the correct pricing signal to customers under a critical peak pricing rate, the critical peak period costs need to be unbundled from the revenue requirement and recovered from customers only when a critical peak event is called. The Commission should calculate non-critical peak rates based on an adopted revenue requirement for all hours that reflects expected costs in a year with no critical peak events. Separately, the Commission should establish the rate for the critical peak period to reflect the utility's anticipated marginal cost to procure for power for those customers during critical peak periods.[40]

The CA CPP Order goes on to explain that:

> By calculating rates in this manner, we do not need to establish any particular crediting mechanism for when an event is called, since the revenue requirement being collected from customers on the critical peak pricing rates during non-event hours has already excluded the costs associated with meeting the utility's critical peak needs.[41]

CPP pricing can provide a number of benefits beyond those provided by traditional TOU rates. CPP can be an effective demand response mechanism to help states that need new generation capacity to manage system peak periods without straining the system. In other words, CPP can help to avoid high generation and transmission marginal costs at critical peak periods. This can be a real benefit to customers.

3. Real Time Pricing

Real time pricing (RTP) represents the most dynamic time-sensitive form of pricing, as the kWh charge varies hourly (or more often) based on marginal energy costs or market prices, quoted in advance. PURPA §111(d)(14)(B)(iii) defines RTP as:

> [E]lectricity prices … set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly.

[39] Specifically the CPP Decision states: "In order to send the correct pricing signal to customers under a critical peak pricing rate, the critical peak period costs need to be unbundled from the revenue requirement and recovered from customers only when a critical peak event is called. The utilities should establish a revenue requirement for non-critical peak hours assuming no critical peak events and rates to collect that revenue requirement. The utilities should separately identify the costs to meet the critical peak, and charge those costs to usage only during the critical peak." CA CPP Decision, *supra* note 35, p. 79 (paragraph numbering omitted).

[40] Id., p. 46.

[41] Id., p. 48.

RTP programs may price energy hourly for all energy consumed or for only part of it through two-part rates. One approach that has been adopted for commercial/industrial inverted rates involves a customer-specific first block that is based on the consumption level in a specified year ("customer baseline" or CBL) and does not change except under extraordinary circumstances.[42] To ensure revenue neutrality and reduce volatility, a predetermined customer baseline load or CBL is charged at the standard tariff. Changes in consumption are measured against this CBL and priced at the RTP (hourly market price or estimate of system lambda) for all additional usage. This places large and small customers within a class on a more equal footing, as compared to inverted block rate structures.

Implementation of real-time pricing structures requires expenditures to modify billing, metering, and communication systems, train employees, and educate customers, which typically exceed the implementation costs of traditional TOU rates. RTP requires smart (interval) meters and often uses a two-way communication system to allow real-time transmittal of hourly prices and real-time meter readings. However, RTP provides additional system benefits not available from standard TOU rates, as they more closely reflect real-time marginal costs in prices.

RTP prices may be based on actual market prices or on the utility's own estimates of hourly marginal costs plus a margin or risk premium. For insurance against price volatility during specific time periods, some RTP programs allow customers to buy risk management tools, such as contracts for differences (CfDs), caps, and collars. The prices of these risk management tools should reflect efficiently the underlying risk management service that is provided.

An analysis of the impacts of introducing RTP rates is a complex task. It requires a full cost-benefit study that considers not only the direct implementation costs but also the potential energy cost savings and other net benefits that arise as customers respond to market price signals. For example, load shifting from peak to off-peak hours should eventually allow a utility to defer expansion of the transmission, subtransmission, and primary distribution systems. There is also a trade-off between efficiency goals and most customers' desire for rate stability. All of these elements need to be considered when designing RTP rates.

The complexity of RTP rates and consumer fear when adopting new price schedules may hinder the implementation of voluntary RTP tariffs. To improve their acceptance and increase their rate of implementation, the following steps can be taken:

- Invest in customer education and marketing (so that customers understand the savings opportunities).
- Offer financial risk management products.
- Coordinate RTP with other demand response activities and energy efficiency programs.

State regulatory policy goals can impact the utility's incentives to adopt the RTP standards. For example, in California, the CPUC established specific goals for investor-owned utilities—they must achieve peak savings equivalent to 5 percent of the state's projected peak demand in 2007, through demand response programs and dynamic pricing tariffs.[43] While such policies encourage the utility to maximize the level of price response generated by RTP, CPP, and other dynamic tariff elements, imposing arbitrary targets should be approached with caution. Such targets can distort markets, lead to uneconomic behavior, and increase consumer costs. For large customers, setting RTP as the default service may serve to encourage retail access by increasing the

[42] Such as a major change in scale of operation.

[43] California Energy Commission, Feasibility of Implementing Dynamic Pricing in California, October 2003, p. 3.

value-added services available to competitive retailers (as compared to the default service) to include fixed priced service.[44]

4. Credits for Customers with Large Loads Who Enter into Pre-Established Peak Load Reduction Agreements that Reduce a Utility's Planned Capacity Obligations

The Smart Metering Standard at PURPA §111(d)(14)(B)(iv) allows "credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations."[45] The amount of this credit, in the event that one is adopted, should be no greater than the costs that the utility *avoids* because it can interrupt a consumer with a large load that signs a peak load reduction agreement.

This may sound familiar to some readers (to quote Yogi Berra once again, it's "deja vu all over again").[46] In the 1980s, IRP processes were used to select new generation resources and demand-side alternatives to those resources. These IRP processes were widely viewed as inefficient, inflexible, cumbersome, costly to customers, litigious, and unlikely to result in the addition of efficient resources in a timely manner. Moreover, many of the demand-side resources proved to be unreliable—they simply weren't there when needed. Regulators should think carefully before moving down this path once again.

There were particularly difficult issues in the 1980s having to do with setting *avoided cost*s for utility purchases from certain generating facilities. Because of the passage of PURPA in 1978, state regulators had to deal with requests that an electric utility be required to sign a long-term contract to buy electricity capacity and energy from new entities, called Qualifying Facilities (QFs). The pricing of utility power purchase agreements was based on the utility's avoided cost—the cost that the utility and its customers would have borne if some other generating resource had been selected. Also, the utility was frequently required to sign a long-term contract (often as long as 15 to 30 years) to support the resource. Professor Alfred E. Kahn notes that this aspect of PURPA of 1978:

> [led] to multi-billion dollar errors, in part because of a deliberate policy of giving a special boost to the entry of independent generators and in part inadvertently … they made genuine errors in projecting those avoided costs—unsurprisingly, in consideration of the perceived energy crisis during the course of which PURPA was passed and the widespread expectations that the price of oil might by the end of the century reach $100 a barrel.[47]

There is a long list of "QF buyouts," by which utilities have paid many millions of dollars to get out from under costly long-term contracts, many of which flowed from avoided costs that were set too high. Further, many of the 1980s-era power purchase contracts with non-utility generators were inflexible (sometimes designated as "must-run" facilities)—typically requiring the utility to take electricity even when it was uneconomical for it to do so.

[44] For example, Public Service Electric and Gas Company uses real-time hourly LMPs as default service rates for its large customers.

[45] PURPA §111(d)(14)(B)(iv) in U.S. Code 16 U.S.C. 2621(d) as amended in EPAct Section 1252(a).

[46] Berra, *supra* note 4.

[47] Alfred E. Kahn, *Letting Go: Deregulating the Process of Deregulation, or: Temptation of the Kleptocrats and the Political Economy of Regulatory Disingenuousness* (East Lansing, MI: MSU Institute of Public Utilities and Network Industries, 1998), pp. 18-19.

With this background in mind, let us consider carefully the specific language of the new revisions of PURPA for this type of time-based rate. Many of the original PURPA problem issues are present, albeit perhaps cloaked in slightly different language. This type of time-based rate schedule has the following elements:

- *Credits*. A basic premise of PURPA is that utility customers should not be made worse off as a result of a utility purchase of a "resource." In this case, the "resource" would be the demand of the large customer who enters into a pre-established load reduction agreement. Thus, the credit should be based on the cost that the utility and its customers would have borne but for the load reduction.
- *For consumers with large loads*. Each state has already established tariff schedules for large customers, which could be used to define this term.
- *Who enter into pre-established peak load reduction agreements*. The basic question here is whether the industrial customer has made a *credible commitment* to reduce its peak load. Absent that credible commitment, the costs that a utility would avoid as a result of the "agreement" with the customer would be minimal. Given the utility's obligation to serve and the uncertainty and variability of exactly when a peak period occurs in a given year, regulators should hold the customer to a high standard. Otherwise, the customer who signs the pre-established peak load reduction agreement could receive a "windfall" benefit at the expense of other utility customers.
- *That reduces a utility's planned capacity obligations*. Given a utility's obligation to provide safe, adequate, and reliable service to customers, only a fully credible commitment by a customer would allow a utility to reduce its planned capacity obligations. A very high standard must be met before the utility could actually reduce its planned capacity because of a pre-established peak load reduction agreement. The regulator (and the utility) would have to verify that the customer is actually lowering load in response to the credit. Finally, there may be issues of free-riding among customers; care would need to be taken to ensure that the credits given to particular customers are not overstated.

Setting the amount of this credit will be a difficult ratemaking challenge for regulators in the absence of a transparent wholesale power market. This is because the avoided cost can change over time. For example, assume that an interruptible rate is established during a period when a utility had substantial excess base load generating capacity such that "peakers" were not needed even on the hottest day of the year and the avoided cost, if any, is low. (In fact, in these circumstances, one could question whether the utility should even offer the rate.) Once peakers *are* needed on the hottest day of the year, however, the avoided cost to the utility may be much higher—but it would only have to "pay" interruptible customers the avoided cost that had been set administratively until such time as the rates are re-set. Thus, administratively-set credits would have an important defect: they are *static (as well as highly litigious)* in nature, while wholesale power markets are dynamic. Administratively-set credits could easily become stale in dynamic power markets.[48] One lesson of experience with PURPA avoided costs in the 1980s is that setting avoided costs rates, in the absence of market prices, is a very difficult thing to do, which suggests that it may be best to not use this approach in regions where wholesale market price information is not readily available.

Rather than rely on administratively-set interruptible rates, the prices set in transparent wholesale power markets can be used to set the credit for customers with large loads. When a utility is part of an ISO or a large RTO, interruptible programs need to be compatible with the ISO/RTO emergency conditions. After all, the marginal value of a curtailment is based on the real-time market prices for reserves or balancing energy that the utility faces in the margin. Thus, the credit would float with wholesale power costs rather than being

[48] This calls into question whether credits of this type are needed. Charging the correct time-differentiated prices will encourage large customers to use less on-peak energy and capacity—and that, after all, is the whole point of the smart meters, which no one argues are not efficient for large customers.

fixed. This is the case, for example, with respect to the New York ISO's day-ahead demand response program.[49] The basic principle should be that the credit should reflect the power costs that are avoided because of the interruptible program. The credit should not be set at an artificially high price that provides a windfall to customers who interrupt.

[49] The New York Independent System Operator (NYISO) explains that "[t]he NYISO's Reliability Demand Response programs, the Emergency Demand Response Program (EDRP) and ICAP Special Case Resources (SCR) program, are intended to provide System Operators with additional resources that can be deployed in the event of energy shortages to maintain the reliability of the system. The NYISO's Day-Ahead Demand Response Program (DADRP) allows energy users to bid their load reductions … into the day-ahead energy market just as generators do. Offers that are determined to be economic are paid the market clearing price. DADRP allows flexible loads to effectively increase the amount of supply in the market and thereby moderate prices." New York Independent System Operator, Demand Response Programs, http://www.nyiso.com/public/products/demand_response/index.jsp (accessed April 11, 2006).

V. THE NET METERING STANDARD

PURPA §111(d)(11) requires that state regulators consider whether or not to adopt a net metering standard. After reviewing the standard that EPAct asks the states to consider, this section will consider the basic case for net metering and the role of smart meters in implementing it.

A. Tasks for State Regulators

PURPA §112(b)(3)(A), which deals with net metering and additional standards, requires that state regulators begin a proceeding to consider whether or not to adopt PURPA §111(d)(11)'s standard within two years of enactment.[50] State regulators must reach a decision within three years of enactment.

The standard that the states are to consider is as follows:

> (11) NET METERING.—Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term 'net metering service' means service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period.

B. Net Metering, Distributed Generation, and Smart Meters

Net metering—which has allowed the electric meters of customers with generating facilities to run backwards when their generator is producing more electricity than they demand themselves—has provided a subsidy to DG customer-generators.[51] With the use of smart meters, however, DG customer-generators can be provided with a reasonable payment for their electricity that is based on the utility's avoided costs.

Distributed generation resources include power producing (supply-side) technologies that are installed in a dispersed fashion throughout a utility distribution system, including at end-user locations. Efficient distributed resources are those that result in net benefits: total cost reductions greater than the costs of installation and operation of the distributed resource. DG can potentially lower the total cost of electric generation if the "all-in" costs of the DG are less than the costs of central plant generators. In principle, DG can reduce demand on part of a distribution system and thereby—perhaps—allow the utility to avoid or delay future capital investment, provided that the reduction of load on the system is permanent. This does not, however, reduce the costs of the distribution system already in place to serve customers. DG could have other benefits as well, such as reductions in transmission congestion and avoided generation costs. The specific implications of a particular DG application can vary widely depending on what DG technology is used, where it is located on the distribution and transmission systems, whether additional generation resources are needed in that location, and so on, but that does not mean that DG should be subsidized. In practice, utility sales that

[50] There are some certain exceptions for states that have already adopted or recently considered a similar standard.

[51] This would not be necessary if two meters were used at the customer's premises, one for electricity usage and one for electricity production. Most states have typically not used this approach. Regulators have reduced the aggregate amount of the subsidy by limiting the availability of net metering in various ways, e.g., to smaller customers of the utility.

are displaced by DG will tend to result in cost shifting from DG customers to utility shareholders and/or non-DG customers because most utility costs, including fixed costs, are recovered on a "throughput" basis.[52]

Net metering is used for utility customers with DG facilities that allow them to sell power to the utility when the customer's generation production is greater than its needs. DG can allow a utility customer to bypass the electric distributor for most of its energy usage, while still imposing costs on the distributor. The customer may be reducing or avoiding purchases of energy from the grid, but the distributor must still maintain the transmission and distribution infrastructure to serve the customer's needs. Because of the "throughput" issue identified above, sales that are lost to DG lead either to under-recovery of its allowed revenue or increases in other (that is, non-DG) customers' rates. This situation is exacerbated by net metering when the customer-generator produces more energy than it is concurrently consuming and the meter runs backwards. This results in a payment from the utility to the customer at full retail price, a payment that is in excess of the costs that the utility avoids as a result of receiving generation from the customer. So not only does the utility under-recover its revenue requirements due to lower sales, it is also paying out additional monies to customers with net metering.

DG thus presents a number of price design challenges for utility regulators, and economically correct standby/backup rates are part of the solution to this problem. Smart meters can accommodate the economically correct pricing of utility purchases of electricity from a DG provider by recording separately the energy flows to the customer, from the customer, and the amount of energy that the customer is producing. With that information, the customer could be properly billed for the service(s) from the utility, and properly compensated for the time-based wholesale value of the energy that it produced and exported into the utility's system. The payment should be based on the wholesale power costs that the utility avoids as a result of the availability of power from the DG customer/generator. Smart meters can thus prevent the subsidization of net metering customers.

[52] In principle, of course, this mispricing could be addressed through appropriate modifications in the rate structure itself.

VI. METERING AND COMMUNICATIONS TECHNOLOGIES: Which Ones Are Capable of Enabling the Use of Time-Based Rate Schedules? And What Are the Potential Benefits and Costs of These Meters?

There is evidence that the deployment of smart meters is becoming more economical, which suggests that the cost of using smart meters may have declined substantially in recent years.[53] Truly enormous changes in communications technology, including but not limited to wireless communications, facilitate substantially more sophisticated pricing capabilities (e.g., transmitting of real time price information directly to customers) and thereby make the deployment of smart meters cost-effective.

More cost-effective choices for metering and communications technologies are becoming available to utilities.[54] Nevertheless, the cost of replacing existing (possibly fully depreciated) meters remains significant. Given the potential rate impact of wide-scale meter replacement programs, care needs to be taken when considering the replacement of existing meters.

An analogy may be useful here. Most homeowners do not replace their refrigerator if they can help it, as long as the existing refrigerator is doing the job and buying a new unit would require a hefty payment. If the existing refrigerator is not doing the job, however, most homeowners act quickly to replace it. Also, a homeowner may replace a refrigerator early as part of a larger project, such as remodeling the kitchen.

Similarly, while the cost of new metering is dropping, the up-front cost remains a significant consideration. In some places, an electric meter may be replaced earlier in order to accommodate other policy goals, e.g., increasing the use of time-based rates in order to reduce system peaks or to provide other benefits, such as better monitoring of system outages. In this context, the decision to replace the meter should not be considered narrowly, but as part of the overall consideration of the new policy initiative.

The economic feasibility of “one-at-a time” versus system-wide deployment of the smart metering technology and the related communications infrastructure should be examined carefully before essentially irreversible decisions are made to replace existing meters.

[53] Also, Steve Hadden of Plexus Research Inc. informed us that from 1998 to 2003, the real (i.e., inflation-adjusted) price paid by utilities for meter AMR communications devices declined by about 22 percent. Email communication from Steven Hadden on March 21, 2006.

[54] Our colleague, Veronica Irastorza, points out that the growing market share of smart meters is evidence that more meter upgrades are passing the cost-benefit test. *See* Veronica Irastorza, “New Metering Enables Simplified and More Efficient Rate Structures,” *Electricity Journal*, December 2005, pp. 53-61. Care needs to be taken when examining the costs of smart meter deployment programs because the results are typically application specific.

In Ontario, for example, the capital costs per month of smart meters are estimated to be Can$250, over a 15-year life, when deployed on a mass scale.[55] The net cost per month for residential customers is estimated to be Can$3.50 per residential customer.[56] Since this is about 3.2 percent of a typical residential bill in Ontario,[57] the cost threshold for installation of new metering technologies remains relevant, while the level of benefits is still undetermined. But, the Ontario Smart Meter Report found that:

> It is estimated that one-at-a-time installations of residential meters cost five times more to complete than a mass deployment. Allowing residential and small general service customers to request early meter installations would result in higher costs and grossly underused communication infrastructure. For example, a network capable of supporting hundreds of meters might only be supporting a few. This would increase load costs at the beginning of the program. It is not recommended that smaller customers be allowed to request early installation.[58]

Because the new Smart Metering Standard at PURPA §111(d)(14)(C) does not anticipate mass deployment of smart meters, specifying that the electric utility provide smart meters in response to customer requests, the cost of one-at-a-time installation of smart meters may be a real concern for regulators. In addition, the one-at-a-time nature of the PURPA Smart Metering Standard lends itself to additional adverse selection and volunteerism issues.

Metering technologies, metering communications, and cost/benefit considerations are briefly listed below. More detailed and in-depth discussion of these elements can be found in “Direct Access Metering & Data Communication Requirements” by Plexus Research, Inc.[59]

A. Metering Technologies

A number of metering technologies are available, which include:

- *Induction meters*. Electromechanical meters measure electricity use without considering the TOU and aggregate over a billing cycle.[60] Some meters track not only consumption but also record maximum demand. Most users rely on induction meters.

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[55] The EPAct 2005 standards are based on voluntary deployment of smart meters, not mass deployment. Thus, this example is not exactly on point. Yet, Ontario does provide an illustration of the costs of deploying smart meters.

[56] Smart Meter Implementation Plan, Ontario Energy Board, Report of the Board To the Minister, January 26, 2005, Appendix C; Costs, p. 103.

[57] A typical residential bill in Ontario with a usage of 1,000 KWh as of April 1, 2005 is Can$105/month. *See* Ontario Power Authority, “Electricity Sector Development: Stabilizing Prices, Background.” Available on the internet at: http://www.powerauthority.on.ca/Page.asp?PageID=122&ContentID=842&SiteNodeID=132 (accessed on February 28, 2006).

[58] Smart Meter Implementation Plan, <u>supra</u> note 56, p. 20.

[59] Plexus Research, Inc., “A White Paper on Direct Access Metering & Data Communication Requirements,” prepared for the National Association of Regulatory Commissioners, March 31, 1998. Plexus is currently undertaking an update to this paper for EEI.

[60] Some induction meters can be retrofitted with communications modules that permit automatic meter reading. Utilities may also replace induction meters with solid state meters which are more accurate and reduce the meed for sampling to ensure accuracy. The solid state meters are also able to register much lower levels of consumption, and can remotely read exactly what is displayed on the meter instead of calculating differences. This results in the homogenization of meters for all customers, regardless of voltage level.

- *Electronic meters*. These meters have begun to replace induction meters. The simplest electronic meters calculate kWh and kW usage for several TOU periods (*e.g.*, on-peak/off-peak).
- *Interval meters*. These meters can provide usage data for each hour or even more frequently (every fifteen, five or even one minute). Many large electricity users have these meters.

B. Metering Communications

In the past, meters were only read manually, which typically resulted in 300 meters read a day per meter reader.[61] This method is adequate if the ultimate goal is to simply record monthly consumption. However, to the extent that we want to record hourly data, manual methods are clearly inadequate. As a result, new technologies have emerged and become more popular as their costs have gone down.

- *Simple Automatic Meter Reading* has been gaining ground over the last 15 years. The simplest AMR system allows readings to be transmitted from the meter using short-distance, low-power, unlicensed radio frequencies. Thousands of readings can be captured by one person in a single day using a mobile AMR system.[62] This system is typically used to acquire monthly meter readings.
- *Fixed Network AMR system*. Here the meter communicates with a stationary data concentrator instead of a roving vehicle. These systems have many advantages, including the ability to read a meter frequently and the ability to monitor outages and system utilization.[63] Typically, fixed network systems cost 35 percent to 70 percent more than the drive-by systems, but many utilities (and their regulators) find that the benefits justify the cost difference.[64]
- *Power line carriers*. This system requires a node at each substation and therefore the viability largely depends on the number of customers per transformer.
- *Telephone line communication.* Systems relying on telephone line communication do not require a geographic concentration of customers on the program, but have many challenges, such as issues related to sharing the use of the phone line.

C. Cost/Benefit Considerations

Replacing or retrofitting all existing manually read meters and installing AMR is expensive. Key cost-benefit considerations when evaluating which rate options should be adopted include the following:

- The costs of time-based meters have fallen significantly; they are only slightly above the cost of traditional meters.
- The costs of AMR must be weighed against: (a) the benefits from lower costs of meter reading, meter tampering detection, and outage monitoring; (b) the potential for new lines of business using communication technologies; and (c) the efficiency gains from the enhanced ability to set price based on marginal cost.
- From the standpoint of a payback ratio, it may be as low as four years. ENEL, in Italy, estimates that its €2 billion investment will pay for itself in about four years.[65]

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[61] Carl Nichols, *Proving AMR's Value, Duke Power on Pace to Surpass 1 Million Automated Meters This Year*, *Energy Customer Management* (published by Public Utilities Reports), Spring 2003, pp. 24-25.

[62] Id.

[63] The meter on demand feature would be useful when a service representative is talking to a customer or when an occupant moves out of or into a building.

[64] For example, the California PUC requires investor-owned utilities to implement rates supported by fixed network AMR systems.

[65] Irastorza, s*upra* note 54, p. 58.

A broader perspective on whether to replace meters may be needed in some instances. Ontario, for example, has a major initiative underway to close 7,500 megawatts of coal-fired capacity by 2007.[66] Whatever the merits or demerits of that policy, a far greater emphasis on time-based rates may be needed to accomplish that goal. Similarly, in California, where peak demand is growing and it is very difficult to build new capacity, a heightened focus on CPP and other time-based rates may be justified. Also, automatic meter reading can result in cost savings, which could offset some of the costs of smart meters. When broad public policy considerations are factored in, a policy decision to invest in new meter reading technology could be justifiable.

[66] Electricity Conservation and Supply Task Force, “Tough Choices: Addressing Ontario's Power Needs,” Final Report to the Ontario Minister of Energy, January 2004, p. 4.

VII. EVALUATION AND CONCLUSIONS

Appropriately designed time-based rate designs—such as TOU, seasonal, interruptible, and real-time rates—that provide accurate price signals can lead to more informed usage decisions by customers and could have clear benefits in the current environment. However, the jury is still out on the efficiency gains that voluntary time-based rate structures can provide, especially for residential customers. While it is difficult for economists not to believe that better pricing of electricity can benefit society, it seems unlikely that voluntary time-based rate structures can fully realize those benefits.

The jury is also still out on smart meters. Smart meters have significant capabilities such that deployment to customers that request them could be beneficial to the general body of ratepayers. For net metering customers, in particular, smart meters could reduce the subsidy flows, thereby providing clear benefits to non-DG customers. Company-specific studies of the benefits and costs of smart meters are needed.

Providing *all* utility customers with better price signals is a premise underlying federal and (some) states' policies introducing greater reliance on competition in recent years. Reliance on price signals is at the heart of these policies—and states continue to grapple with ways to allow wholesale prices to "shine through" into retail rates. Getting this price information to the customer in a timely manner is an important part of successfully implementing time-based rate designs.

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