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Advanced Metering Infrastructure: What Regulators Need to Know About Its Value to Residential Customers

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Executive Summary

I. Introduction and Overview

This report began as an effort to understand who has the better argument: those opposed to "advanced metering infrastructure" (AMI) as a demand response tool, and those supporting AMI for the same reason. As our understanding of the AMI issues has evolved, the paper has evolved. The report now casts a wider web.

We provide regulators with a general framework for evaluating an electric utility's request for recovery of the costs of implementing an advanced metering infrastructure.[1] We do return to, and examine in depth, the disputes between consumer advocates who oppose AMI and environmentalists, and utilities who support AMI. We place these disagreements in the context of a model for analyzing the overall costs and benefits of AMI.

In the first section, we provide an overview of the report and define AMI. We use the definition of advanced metering infrastructure that the Federal Energy Regulatory Commission (FERC) Staff uses:

> ...a metering system that records customer consumption (and possibly other parameters) hourly or more frequently *and* that provides for daily or more frequent transmittal of measurements over a communication network *to* a central collection point. AMI *includes* the communications hardware and software and associated system and data management software that create a network between advanced meters and utility business systems and which allows collection *and distribution of information to* customers and other parties such as competitive retail providers, in addition to providing it to the utility itself.[2]

We also note a number of additional issues that a regulator will want to resolve before determining whether to approve AMI cost recovery. For example, the report does not discuss whether pre-approval of AMI (or any other utility investment) is warranted. Similarly, the report does not try to recommend a useful life of AMI components for use in a net present value evaluation. Such a value is key to the evaluation and likely to be the subject of disagreement among experts and the parties.

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[1] Gas utilities can and do implement AMI, although they cannot use all the functionalities of AMI that an electric utility can, particularly remote connection and disconnection. The gas demand response initiatives using AMI are likely to be different from those of an electric utility as well. This report does not discuss AMI in a gas utility setting.

[2] *FERC Staff Report*, Appendix A (Glossary) (emphasis supplied).

In the first section we also distinguish AMI from other technologies and systems that are sometimes confused with AMI, and from other technologies and systems that can be used to provide demand response offerings to consumers without the cost of a complete AMI system. We introduce a recurring theme: AMI is one way, but only one way, for a utility to offer time-varying utility prices and induce demand response. Proponents and opponents of AMI agree on this point.

There are numerous configurations of advanced metering, communications networks, and back-office applications and software installed in an AMI project. Each will give the utility different sets of functions, and different associated costs. To provide an example, we put forward the California definition of functions that must be included for a project to be considered AMI:

Figure ES-1: AMI Minimum Functionality (after California PUC Requirements)

a. Supports implementation of time-varying tariffs for:
   1. Residential and small commercial customers (under 200 kW):
      i. Time-of-Use (TOU) rates;
      ii. Critical Peak Pricing[3] with fixed notification (CPP- F) and CPP with variable or hourly notification (CPP-V) ;
      iii. Flat/inverted tier rates.
   2. Large customers (200 kW to 1 MW) on an opt-out basis:
      i. Critical Peak Pricing with fixed or variable notification;
      ii. Time-of-Use rates;
      iii. Two part hourly Real-Time Pricing.
   3. Very large customers (over 1 MW) on an opt-out basis:
      i. Two-part hourly Real-Time Pricing;
      ii. Critical Peak Pricing with fixed or variable notification;
      iii. Time-of-Use Pricing.
b. Allows collection of usage data at a level of detail that supports customer understanding of hourly usage patterns and how those usage patterns relate to energy costs.
c. Provides customer access to personal energy usage data with sufficient flexibility to ensure that changes in customer preference of access frequency do not result in additional AMI system hardware costs.
d. Compatible with applications that (1) use collected data to provide customer education, energy management information and customized billing; and (2) support improved complaint resolution.
e. Compatible with utility system applications that promote and enhance system operating efficiency and improve service reliability, such as remote meter reading, outage management, reduction of theft and diversion, improved forecasting, workforce management, etc.
f. Capable of interfacing with load control communication technology.

[3] The "critical peak" consists of the small number of hours during a year during which most or all of the available generation resources are needed to meet demand.

II. Structure of an AMI Cost-Benefit Analysis

In the second section, we provide a recommended structure for evaluating whether to allow AMI costs in utility rates. We note that AMI is a major investment, like other major uses of utility capital and management focus. In general, a utility investment must be used and useful in the service of its customers, its benefits must exceed its costs, and it also must be more cost-effective than all reasonable alternatives that exist for accomplishing the same functions or achieving the same benefits.

To evaluate AMI under these principles, a regulator will of course need reliable information on the costs and benefits of AMI for the utility in question, as well as the costs and benefits of reasonable alternatives.

In this second section, we set out a number of the publicly available estimates of AMI investment cost. As the name implies, an advanced meter infrastructure is more than an advanced meter, capable of recording usage over discrete time periods. Depending on the configuration of the particular AMI, the type of communications network installed, the meter functionalities, the back-office system, and software changes made to use certain functionalities, AMI can cost anywhere from $100 to $525 per meter.

The second section also introduces the benefits of AMI. Two major cost savings opportunities are associated with AMI, and AMI makes a number of service improvements possible.

Operational savings made possible by implementation of an advanced metering infrastructure come primarily from reduced meter reading costs and other substitutions of AMI technology for more costly labor. For utilities that do not already use automated (e.g. drive-by) meter reading, these operational savings represent well over 50 percent of all cost savings attributable to AMI. We provide a number of examples of the kinds of operational benefits claimed by utilities for AMI in their service area, with breakouts of the relative contribution of the specific cost savings to the overall operational cost reduction.[4]

Resource cost savings from using AMI would result from and be determined by the extent of persistent demand reductions achieved by introducing dynamic pricing and demand response programs implemented using AMI technology. The costs of providing energy (generation costs) vary tremendously from hour to hour within a day. Across the country, 10 percent of the peak demand is concentrated in the top 1 percent of the hours of the year. If a cost-effective means could be found to shave some of this critical peak, great resources savings would be possible. Time-varying pricing is one tool that arguably can induce such peak load reductions. As discussed in some depth in Section III of the report, much of the debate over AMI centers on whether residential customers can and will respond to such time-varying pricing.

[4] We also note that one possible source of cost savings, remote connection and disconnection, can have adverse impacts on low-income customers, among others, and is barred by statute or rule in some states.

Service improvements include faster and more precise identification of outages, more accurate metering and billing, and the like.

III. Impacts of Time-Varying Prices on Residential Customers

In Section III, we focus on whether and to what extent residential customers can and will reduce demand in response to price signals and demand response programs implemented using an advanced metering infrastructure. We will also consider whether the response of different subsets of residential customers varies, such that AMI might be beneficial for some residential customers and pose risks to others.

Utilities and AMI supporters claim that AMI will enable utilities to lower societal energy costs over the long term, lower bills for many customer segments in the short-term, and improve service. A fundamental benefit of AMI, they argue, is the ability it provides the utility to offer all customers rates that vary with the time of usage, and thus better match the costs of the system. This in turn, they argue, will induce customers to reduce usage during critical periods of especially high cost. A number of respected consumer advocates oppose the implementation of AMI. They argue that AMI costs more than it saves. In particular, they argue that residential customers cannot take advantage of time-varying prices. Indeed, they claim, low-income and other vulnerable customers will be hurt if forced to take service under rates that are higher during peak periods of high-cost days. They also note that less expensive means to induce load reduction are in use today.

To explore who has the better argument, we look at three major pilots of various forms of time-varying pricing in recent years, each of which was extensively studied and evaluated in published reports. The three pilots are (1) the California Smart Pricing Pilot (CA SPP); (2) the Commonwealth Edison/Community Energy Cooperative Energy-Smart Pricing Plan™ (ESPP); and the Ontario Smart Price Pilot (OSPP). After describing these pilots, we look at each for evidence that answers six key questions:

Figure ES-2: Key Areas of Uncertainty Explored in This Report

1. To what extent did residential customers on average reduce load in response to time-varying pricing in the three best-known pilots?
2. To what extent were the participants in the three pilots representative of residential customers, including particular subsets of such customers?
3. Did low-use or low-income customers respond to time-varying pricing?
4. How persistent, year after year, are the voluntary load shifts or reductions resulting from price signals, with or without smart meters?
5. If demand response tariffs are voluntary, what portion of residential customers is likely to choose such pricing?
6. What are the likely bill impacts from time-varying pricing, on average and for various subgroups of residential customers?

We summarize the answers to the key questions in Section IV. Before leaving Section III, we take a fresh look at the issues from the perspective of the regulator. We note that critical peak pricing and other time-varying pricing is likely to produce "winners" and "losers." We highlight the observation that the identity of these winners and losers will not depend solely on who can shift their usage off peak and avoid mandatory high peak (or critical peak) prices. Two other key factors will come into play. First, those with a relatively flat load shape should do well under time-varying pricing, as off-peak prices are typically lowered in order to keep the entire rate revenue-neutral. As it happens, low-income customers tend to be low-use customers, and low-use residential customers tend to have a relatively flat load shape. Except to the extent that incremental AMI costs overwhelm the benefit of the flat load shape, low-use customers (low-income included) should do well on time-varying pricing.

Second, the extent to which those who cannot shift load will do better or worse than the status quo depends on whether it is necessary to give 100 percent of the benefits made possible by the demand response to those who respond by lowering demand, in order to induce such demand response. If it is, then all customers would be paying for metering that only some customers will be able to use to their benefit. In such a case, the regulator will have a more difficult time convincing the public of the justice of a decision approving the recovery of AMI costs in rates, even if he or she determines that principles of cost-causation in rate design permit (if not require) such an outcome.

We close Section III with a list of the miscellaneous additional issues that a regulator will have to determine in the course of deciding whether to allow AMI costs in rates.

IV. Conclusions and Recommendations

In Section IV, we summarize the factual and policy conclusions reached from our research and analysis. Following is a summary of the answers we reach to our key questions:

Question	Summary Answer
1	Overall, residential customers displayed significant demand reduction in response to critical peak prices. Customers with direct load control devices (such as programmable communicating thermostats) responded at dramatically higher rates (up to 41 percent on critical peak days) than those without such automated control devices (between 10 percent and 15 percent on average). Response of residential customers on average to time-varying pricing varied from group to group, and time to time. In some cases, the mean response was higher than the median (some particularly strong responders pulled the average response up). It is likely that within the averages, individual customers and subsets of residential customers showed widely varying responses to critical peak pricing. Not all responses to time-varying prices were demand reductions. In at least one pilot, participants on average increased usage during certain critical peak periods, despite critical peak pricing and critical peak rebate pricing. In one pilot, half the participants showed no response at all. CPR customers responded to critical peak rebate opportunities, but showed a lower response to critical peak rebate opportunities than CPP customers showed to critical peak prices.
2	Participants in the time-varying pricing pilots were roughly representative of the customer base from which they were drawn, but it is not possible to rule out self-selection bias in the results. Participants were in some cases skewed towards higher-usage, higher-income customers.
3a	Lower-use customers in general reduced their load by lower percentages than higher-use customers. One analysis of California results showed that low-use customers did not reduce loads at all in response to critical peak pricing; another analysis of the same data showed low-use customer response, but not at the same level as for high-use customers. Results were mixed for residents of multifamily buildings, who tend to be among lower-usage households - in the ESPP and OSPP, such customers at times responded more strongly than those in single-family homes. In the California SPP, residents of multi-family homes responded to critical peak pricing, but at lower levels than residents in single-family homes. Low-use customers of all income groups had the highest bill reductions, not counting AMI costs.
3b	Lower-income customers in general reduced load by lower percentages than higher income customers. Results are not definitive about the impacts of CPP or PTR on low-income customers, because income bands in pilot evaluations were not well defined. In one pilot showing strong low-income response, practically all the response came from a handful of customers. In the CA SPP, lower-income/high-usage customers increased usage on critical peak days.
4	The pilots do not provide a basis for estimating how persistent the observed demand responses will be year over year. Past experience with time-varying rates is discouraging on this point, but perhaps not indicative of likely persistence of response over time, given today’s less expensive metering and demand response technologies, the ability to isolate high peak

	prices to a narrow set of critical peak hours, and the ability to program end uses to respond to prices communicated by the utility.
5	Pilots to date provide no useful information regarding the likely participation rates of voluntary time-varying tariffs. Optimistic estimates of 20 percent migration to opt-in time-varying rates and 80 percent opt-out retention rates have no basis.
6	None of the pilots provides readily available information on likely bill impacts of AMI, in that none addresses the allocation of incremental customer costs and time-varying resource cost savings to participants and non-participants. This omission is a major gap in the research to date, and hampers regulators trying to anticipate how an overall positive cost-benefit calculation for AMI will translate to specific customer groups. Findings of lowered bills from time-varying pilot prices must be discounted by the fact that the cost side of the equation ignored AMI costs. Even without counting AMI costs, 20 percent or more of the CA SPP participants on all pilot rates saw higher bills. In the Ontario SPP, 25 percent of the participants had no bill decrease, or had bill increases, on the time-varying tariffs. Among customers with higher bills in the Ontario SPP, CPR customers had larger increases than CPP customers.

The results of several pilots, then, show that residential customers, on average, have responded strongly to various types of dynamic pricing. Critical peak pricing, in particular, has shown promise as a demand response tool for residential customers generally.[5] Further, customers with uses suitable for load control, such as central air conditioning, and who have smart thermostats installed to automate the demand response to price signals, responded much more strongly than other groups. However, not all pilot participants reduced load, not all groups reduced load on average in every circumstance analyzed, and in some cases, participants' critical peak loads went up during the pilot.

Bill impact information is necessary if for no other reason than to gauge popular acceptance of more dynamic pricing. Here, the pilot data is virtually useless, because none of the pilots reflected those incremental AMI costs that would be counted against incremental demand response resource cost savings. Even without reflecting this added cost, some customers experienced high bill increases at certain points in the pilots. For a variety of reasons, low-income high-use customers in at least one pilot experienced large bill increases, again without considering the bill increases associated with that portion of AMI not offset by operational savings. As well, only time will tell whether the results observed in these pilots will persist into the future.

Because of (1) the uncertainties over persistence of demand response under critical peak pricing or rebates; (2) the lack of specific information from the pilot reports about the identity of

[5] This report does not focus on time-of-use rates, as such rates did not call forth the strongest responses in the pilots, and also can readily be implemented without investing in a complete advanced metering infrastructure.

possibly vulnerable customers (making it hard to determine whether, and if so, how to mitigate potential harm to such customers); (3) the relatively small portion of estimated AMI costs that can be covered by operational benefits in some cases; and (4) questions about the extent to which those responding to critical peak prices must receive the entire benefit of their load reductions, leaving no benefit for other customers, it is not possible to conclude that AMI makes sense in all circumstances. Greater efforts to induce persistent critical peak demand reductions are necessary, as future costs of capacity and energy are on track to keep going up. Whether AMI makes sense as the tool to incent demand response is very much open to question.

Turning finally to the recommendations, we begin by acknowledging the uncertainties facing a regulator in evaluating AMI and its alternatives. Most of the thorny issues require answers about what the future will bring. There are two ways a regulator can resolve these uncertainties and decide what action to take: move forward now, or wait until the experience of states with AMI and time-varying pricing helps narrow the uncertainties about the life-cycle costs of AMI and the resource benefits AMI can help induce. Neither involves authorizing further pilots.

What remains is a choice about whether to lead consumers in taking on the AMI risks that time-varying pricing will not succeed as a demand response tool and that AMI costs will prove greater over time than now forecast.

There are enormous challenges facing regulators, electric utilities competitive suppliers and ultimately electricity consumers today: high incremental generation construction costs, high fuel costs, high incremental transmission and distribution infrastructure costs, new and potentially quite expensive environmental constraints on generation, to mention only a few. Some of these pressures are not likely to abate, and will instead intensify over time. Against this background, it could make sense for a regulator to pay some public goodwill and political capital out in the form of leadership in the area of demand response and operations technology, taking the risk that the uncertainties about the costs and benefits of AMI will be resolved against AMI's cost-effectiveness.

It is not likely to require as much political skill to persuade utilities, consumers and other stakeholders to accept time-varying pricing as it has been historically. According to the pilot results, participants expressed satisfaction with pilot time-varying pricing by overwhelming majorities. Some of the historic common sense arguments against time-varying pricing need to be re-examined. Contrary to common assumptions about who can take advantage of peak pricing signals, residential customers in more than one dynamic pricing pilot have successfully lowered demand in response to critical peak pricing. Even low-use and low-income customers have, on average, lowered usage significantly in some circumstances. Low-usage customers also benefit from a relatively flat load shape. It is, in principle, possible to identify and assist customers who are both low-income and high-usage, to prevent them from experiencing major bill increases as a result of an AMI investment and subsequent implementation of time-varying prices.

On the other hand, a regulator could look at the same data and conclude that, at least until some years pass (and demand response from California customers and those in other jurisdictions implementing time-varying pricing remains strong), demand response should not be counted towards the benefits of AMI. In the meanwhile, the regulator should encourage other forms of utility demand response activity.

For example, the dramatic results for customers with programmable communicating thermostats (producing demand responses 50 percent higher than prices alone) may well be achievable by direct load control, implemented without the interposition of AMI's advanced meters and sophisticated communications networks. Similarly, critical peak pricing and rebates could be offered on a targeted basis to customers most likely to respond strongly, using advanced meters but not the rest of the AMI technology. Especially where a utility already has harvested labor savings from automating the meter reading function, AMI may not be cost-effective, and these other alternatives should be pursued.

The best course will vary from service area to service area, from utility to utility, from time to time. Doing nothing about demand response is not an option, in light of the enormous costs that a small amount of peak load shaving can avert. This author tends to be cautious, and considers that utilities seeking approval to recover major investments in rates without a reliable cost-benefit justification should shoulder the risks associated with the uncertainties that remain. With this background in mind, the following are some recommendations that emerge from this review of issues surrounding AMI for residential customers:

Figure ES-3: Recommendations

1. Where automated meter reading has already been installed, regulators should not authorize cost recovery of Advanced Metering Infrastructure until results from California and other states with widespread AMI and time-varying rate options demonstrate persistent and large resource savings from time-varying rates.
2. Regulators should require a full analysis of the merits of AMI whenever a utility requests cost recovery.
3. Where the analysis of costs and benefits of AMI leaves doubt about its net value, regulators should require utilities to take the risks associated with such uncertainty, if they wish to move ahead with AMI.
4. Regulators should not require further pilots before implementing or deciding not to implement AMI.
5. Regulators who have decided not to authorize expenditures on AMI at this time should require periodic updates from utilities concerning levels and persistence of demand responses among customers of utilities with ongoing pilots or full-scale implementation of AMI, and updated information available as to the impact of such AMI investments and any time-varying pricing plans implemented using such AMI on residential customers generally, and on especially vulnerable customers in particular.
6. Regulators should require utilities to develop and implement aggressive, cost-effective demand-response programs, including efficiency as well as Direct Load Control.
7. Regulators should seek access to underlying data on pilots that have been operated to date, and arrange for this data to be analyzed to develop reliable

estimates of (a) bill impacts of AMI and time-varying pricing on different groups of residential customers, and (b) the extent to which customers reduced their demand by taking steps that would be difficult to take year after year.

Advanced Metering Infrastructure:
What Regulators Need to Know About Its Value to Residential Customers

I. Introduction

A. Overview of this report

1. Purpose: Define AMI and recommend methods of assessment, with a focus on residential customers

Utility regulatory commissions across the United States are increasingly seeing utility proposals for investments in so-called "advanced metering infrastructure" (AMI). Utilities and AMI supporters claim that AMI will enable utilities to lower societal energy costs over the long term, lower bills for many customer segments in the short-term, and improve service. The passage of the Energy Policy Act of 2005 has also spurred interest in AMI. Under Sections 1252(e) and (f), it became the policy of the United States to encourage "time-based pricing and other forms of demand response."[6] Proponents of AMI point out that, while other technologies can support time-based pricing and demand response, AMI is one vehicle a utility can use to implement such pricing and demand response.

A number of respected consumer advocates oppose the implementation of AMI. When AMI supporters have proposed AMI investments or pilots of pricing innovations that AMI could support, regulators typically have had to evaluate and decide a number of contested issues. This report will provide a framework that regulators can use to analyze the merits of AMI for an electric utility,[7] with an emphasis on the impact of AMI and its demand-response uses on residential customers.

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[6] EPACT 2005 requires that each state regulatory authority conduct an investigation and issue a decision on whether it is appropriate for electric utilities to provide and install for their customers time-based meters and communications devices, which enable such customers to participate in time-based pricing rate schedules and other demand response programs (Section 115(i) of PURPA). As of July 1, 2007, twelve Commissions had completed the review required under Section 115(i), and another 27 had dockets open. Federal Energy Regulatory Commission (FERC), *2007 Assessment of Demand Response and Advanced Metering, Staff Report* (FERC Staff Report) September 2007, 27.

According to the FERC Staff, by that date, two states had decided to adopt the new PURPA standard, eleven states had decided not to adopt the standard, and four states had deferred the decision. Ibid., Appendix E. The FERC report also collects citations from the various states of legislation, docket filings, Commission orders, and other activities on advanced metering, demand response, and real time pricing initiatives.

[7] AMI can be and is being installed by gas utilities. The relative costs and benefits are different in some respects from those that affect the merits of AMI for electric customers. This

We will begin by defining AMI, and distinguish AMI from other advanced metering and demand response technologies that some utilities have implemented. We then turn to the question of how a regulator determines whether a utility investment, such as AMI, qualifies for cost recovery in rates. In principle, regulators must decide whether the benefits of AMI, such as utility cost savings, outweigh the incremental costs, and are larger than net benefits achievable through alternatives to AMI.

To evaluate AMI under these principles, a regulator will of course need reliable information on the costs and benefits of AMI for the utility in question, as well as the costs and benefits of reasonable alternatives. To begin the analysis of the information presently available on these topics, we will briefly describe the costs a utility will typically incur to implement an advanced metering infrastructure. We will next outline the categories of cost savings and other benefits that a Commission typically will want to assess in determining whether to approve the recovery of AMI costs in rates. We will introduce the two major sources of savings attributed to AMI (operational savings and resource cost savings), and touch on the service improvements possible with an advanced metering infrastructure.

Operational savings made possible by implementation of an advanced metering infrastructure come primarily from reduced meter reading costs and other substitutions of AMI technology for more costly labor. **Resource cost savings** from AMI would result from, and occur proportionate to the extent of, persistent demand reductions achieved by introducing dynamic pricing and demand response programs implemented using AMI technology. **Service improvements** include faster and more precise identification of outages, more accurate metering and billing, and the like.

We will focus on a particular aspect of the estimation of AMI-related resource cost savings. Specifically, we will address whether and to what extent residential customers can and will reduce demand in response to price signals and demand response programs implemented using an advanced metering infrastructure. We will also consider whether the response of different subsets of residential customers varies, such that AMI might be beneficial for some residential customers and pose risks to others.

In considering the merits of implementing AMI, Commissions have been faced with sometimes heated debate over its value as a tool to support residential demand response and thereby lower system resource costs. There is no dispute that shaving peak usage on a sustained basis can lower system costs. Meeting peak demand, of which 10 percent is concentrated in the top 1 percent of hours of the year, requires the installation of generating plants that are idle most of the year, and whose fuel costs are higher than fuel costs for other plants. Their costs-per-kilowatthour-generated are the highest of all plants. For this reason, if a cost-effective means can be found to shave demand off the peak in the long-term, considerable resource savings should be possible.

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memorandum will focus on the electric utility application of AMI, but the general principles of analysis are applicable to gas utilities.

Many economists and rate designers suggest that offering (if not requiring) pricing that varies in relation to changes in the cost of supplying customers would induce many customers to shift their usage patterns in order to use power at less expensive times. Shifting power from the highest-cost peak times to lower-cost shoulder or off-peak times would then lower the average cost of the generation used to supply customers. AMI includes technologies that can be used to offer such time-varying pricing options.[8]

Proponents and opponents of AMI investments disagree about the extent of achievable demand response. They disagree particularly on whether residential customers, and certain vulnerable customers in particular, can and will respond to time-varying pricing by reducing their demand. They further disagree about whether there are cheaper ways to obtain these valuable demand reductions. To help Commissions sort through the assertions made about the potential of AMI to facilitate resource savings from residential customer demand response, we will take an in-depth look at pilot studies of time-varying pricing in three jurisdictions and assess whether they can be relied on to predict how time-varying pricing will work in other states, as well as over time.

We will also explore the net effect of time-varying pricing on residential customers, and on vulnerable customers within the residential class. We will examine what information there is from the pilots concerning the impact of AMI investments on different types of residential customers, including available information on bill impacts. Regulators will want to understand the differences in how AMI and different pricing structures offered using AMI affect residential customers as a whole, as well as their impact on particular groups of residential customers, to satisfy themselves that recovery of AMI costs from all customers is fair and that the public will accept it.

We will touch on some of the alternate means of incenting demand response among residential and other customers. A utility's case for recovery of AMI costs must demonstrate that it has explored all reasonable alternatives to AMI, and that AMI is the least costly of the workable alternatives.

This report will not give equal weight to all the issues that a regulator must examine on the way to determining whether to permit AMI costs to be recovered in rates. Rather, after laying out the overall structure of a regulatory analysis, we will focus on some issues that have dominated the debate over AMI among AMI supporters and consumer advocates who oppose AMI. From this perspective, we will explore in depth what is known about the following questions:

[8] It cannot be repeated too often that AMI is just one set of technologies that can be used to make time-varying pricing possible.

Figure I: Key Areas of Uncertainty Explored in This Report

1. To what extent did residential customers, on average, reduce load in response to time-varying pricing and direct load control in the three best-known pilots?

2. To what extent were the participants in the three pilots representative of residential customers, including particular subsets of such customers?

3. Did low-use or low-income customers respond to time-varying pricing?

4. How persistent, year after year, are the voluntary load shifts or reductions resulting from price signals, with or without smart meters?

5. If demand response tariffs are voluntary, what portion of residential customers is likely to choose such pricing?

6. What are the likely bill impacts from time-varying pricing, on average and for various subgroups of residential customers?

The outcome of an AMI cost-benefit analysis will vary from utility to utility. It is not defensible to state that AMI is always a net benefit or always a net loss for consumers. The evidence available to date does allow us to categorize the major drivers of AMI cost and benefit, and use them to provide recommendations about the direction Commissions should take if their goal is to reduce utility costs and improve utility efficiency, if not also improve utility services. It does not, however, provide a neat formula for deciding whether to approve cost recover of AMI investments.

2. Omitted topics that will require regulatory consideration before approving cost recovery for AMI and time-varying pricing

This report will not try to answer every question a regulator may have about how to evaluate an AMI proposal. It also will not provide guidance on how to determine all benefits or costs of AMI investments. For example, this report will not address the potential for load response among commercial and industrial customers. Further, the report does not attempt to evaluate in detail the cost estimates offered by utilities in support of their initiatives, or the useful life of such investments.

This report also will not address questions of prudence, or externality costs and benefits, although such considerations should occupy a regulator's attention. In particular, we note that some environmentalists and utilities tout time-varying pricing as a means of reducing energy usage and thus emissions, while others stress that the usage reductions on peak can lead to higher emissions if cleaner gas-fired or hydro generation on peak is replaced by additional coal-burning off-peak.

The report will not address concerns recently raised about the exposure of networked utility systems, including links into customers' homes, to hacking and other "cyber"-intrusions.[9] It will also not explore the arguments advanced by some AMI proponents that installation of the advanced metering infrastructure will provide a platform on which new and as-yet-unknown services and functions can be implemented.

In addition, this report will not address whether and under what circumstances regulators should grant pre-approval of any or all AMI costs. A Commission may have different standards for approving the utility's cost recovery at different points in the path from conception to implementation. In this report, we will focus on the overall question of costs and benefits, rather than the distinctions a Commission may draw between the proofs needed for pre-approval and those needed for the inclusion of a plant in service into the rate base (and recognition of expenses actually being incurred).

Nor will we attempt to resolve all the issues that arise when demand response saves a competitive supplier in resource costs, but the competitor's retail contract for such supply does not provide for a flow-through of those savings to the retail customer. This situation commonly occurs in the case of default service arrangements in retail competition states, under present approaches to default service procurement and contracting. Work-arounds are possible eventually through revision of the standard contracts, but the specifics of such contract changes are beyond the scope of this report. Similarly, this report assumes that the utility has a portfolio optimization requirement. In states where the utility not only has no such obligation, but is in fact barred from performing such functions, the pros and cons of AMI installation will have to take into account the split between the distribution utility and the entity or entities responsible for generation planning. AMI proponents justify its costs based on benefits reaped on the distribution and generation sides, not just one or the other.

This report will not address whether fairness, or economic efficiency in the abstract, require or justify time-varying prices. Nor will the report address the pros and cons of AMI, interval metering, and two-way communications in facilitating retail competition.

Finally, we will not try to quantify the relative costs and benefits of a direct load control program, targeted to certain customers a utility expects are likely to be able and willing to allow the utility to reduce their peak loads in response to incentives. Direct load control can be accomplished without AMI, and arguably at less cost, but may produce somewhat greater reductions when supported by AMI. A full analysis of the merits of AMI will need to address these issues as well.

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[9] Ellen Nakashima and Steven Mufson, "Hackers Have Attacked Foreign Utilities, CIA Analyst Says," *Washington Post*, January 19, 2008, A04.

Each of these issues warrants further research, research that this report hopes to stimulate. For those interested in exploring these issues further, we provide a reading list at the end of the report.

B. What is AMI and what can it do?

1. Advanced metering is only part of AMI

"Advanced metering infrastructure," as defined by the Staff of the Federal Energy Regulatory Commission (FERC). is:

> ...a metering system that records customer consumption (and possibly other parameters) hourly or more frequently *and* that provides for daily or more frequent transmittal of measurements over a communication network *to* a central collection point. AMI *includes* the communications hardware and software and associated system and data management software that creates a network between advanced meters and utility business systems and which allows collection *and distribution of information to* customers and other parties such as competitive retail providers, in addition to providing it to the utility itself.[10]

AMI is not limited to advanced meters, but refers to an entire infrastructure that ties advanced meters to a data management system and from there to other utility business systems. "AMI" is not (yet) a term of art. There is no single, universally accepted definition of the components that, taken together, constitute an advanced metering infrastructure.

When analysts, utilities, regulators, stakeholders and others use the term "advanced metering infrastructure" in the case of electric utilities, they do tend to refer broadly to a collection of hardware (e.g. meters and computer processors), software (e.g. billing system computer programs) and other elements that taken together permit the utility to perform certain functions. Below is a list of components that most people have in mind when they use the term:

Figure II: Components of an Advanced Metering Infrastructure

1. Interval meters, that can record and store usage data on hourly or more frequent basis.

2. Two-way communications network between meter and supplier/utility that can send usage data from the meter to the utility; and send pricing, load control and other signals from the utility to the customer's premises.

[10] *FERC Staff Report*, Appendix A (Glossary) (emphasis supplied).

> 3. A meter data management system (MDMS), that can handle large amounts of information concerning individual customer usage profiles.
>
> 4. Revised utility operational software, that can make use of the granular usage data produced through the meters, communications network, and meter data management system.

When AMI is implemented, it is typically implemented system-wide, although the roll-out of the new meters may be done in stages. Eventually, when AMI is fully implemented, advanced meters are in all premises, and the communications systems are in place to connect all of them with the utility's new data management system. An AMI system loses some of its value if it is restricted to certain segments of the customer base. Unless all customers are metered and billed off the same data management system, for example, the utility may have to maintain more than one billing system. It is possible to implement advanced metering, without more, by customer type. But it is not sensible to implement the entire advanced metering infrastructure (AMI) on a piecemeal basis, installing new meters and communications links for some customers but not all, and then running two meter data managements systems and two sets of back-office software (one for those customers with AMI, and the old one for customers who do not yet have AMI).

There are a large number of variations of technology within the rubric of advanced metering infrastructure. A utility will design an AMI system to include the technologies needed to perform, at a minimum, a desired set of functions at the least cost, while also leaving open the option to add on to or modify the system as the technology evolves.[11]

2. AMI supports a variety of utility functions

Not all utilities with AMI systems use them to perform all the functions that such systems, at least in theory, can perform. It can be useful, when considering a multi-million dollar investment such as an AMI, for a utility to design the system so that it will be capable of adaptation to new functions over time. With this in mind, the California PUC recently promulgated a list of the functions that an AMI system must enable a utility to perform, if the utility wishes to recover the costs of an AMI investment.[12] The Commission has not held itself

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[11] Edison Electric Institute has published a valuable primer on AMI technologies, prepared by Plexus Research, Inc.: *Deciding on "Smart" Meters: The Technology Implications of Section 1252 of the Energy Policy Act Of 2005*, a report prepared for the Edison Electric Institute (EEI), September 2006.

[12] Assigned Commissioner and ALJ Ruling, in the docket captioned "Order Instituting Rulemaking on Policies and Practices For Advanced Metering, Demand Response and Dynamic Pricing (Advanced Metering Final Decision)," *Rulemaking* 02-06-001, February 19, 2004, 3-4. This Assigned Commissioner ruling has been endorsed and applied (as adjusted) in subsequent decisions of the full Commission. See, e.g., *Application of Pacific Gas and Electric Company for Authority to Increase Revenue Requirements to Recover the Costs to Deploy an Advanced*

slavishly to this list, but has required utilities to justify deviations from this list. The California PUC list is a good starting point for understanding the uses to which a utility can put AMI, and the functions that AMI typically performs for a utility.[13]

Figure III: AMI Minimum Functionality per California Minimum PUC

a. Supports implementation of time-varying tariffs for:
   1. Residential and small commercial customers (under 200 kW):
      i. Two- or three-period Time-of-Use (TOU) rates, with ability to change TOU period length;
      ii. Critical Peak Pricing[14] with fixed (day ahead) notification (CPP- F);
      iii. Critical Peak Pricing with variable or hourly notification (CPP-V) rates;
      iv. Flat/inverted tier rates.[15]
   2 Large customers (200 kW to 1 MW) on an opt-out basis:
      i. Critical Peak Pricing with fixed or variable notification;
      ii. Time-of-Use;
      iii Two part hourly Real-Time Pricing.
   3. Very large customers (over 1 MW) on an opt-out basis:
      i. Two-part hourly Real-Time Pricing;
      ii. Critical Peak Pricing with fixed or variable notification;
      iii. Time-of-Use Pricing.

b. Allows collection of usage data at a level of detail that supports customer understanding of hourly usage patterns and how those usage patterns relate to energy costs.

c. Provides customer access to personal energy usage data with sufficient flexibility to ensure that changes in customer preference of access frequency do not result in additional AMI system hardware costs.

d. Compatible with applications that (1) use collected data to provide customer education, energy management information and customized billing; and (2) support improved complaint resolution.

e. Compatible with utility system applications that promote and enhance system operating efficiency and improve service reliability, such as remote meter reading, outage management, reduction of theft and diversion, improved forecasting, workforce management, etc.

f. Capable of interfacing with load control communication technology.

Metering Infrastructure, Final Opinion Authorizing Pacific Gas and Electric Company to Deploy Advanced Metering Infrastructure *(PG&E Final Opinion)***,** Decision 06-07-027 (CA PUC) July 20, 2006, at 23.

[13] The CPUC uses the term "price-responsive" rates, meaning rates designed to incent customers to respond by increasing or decreasing demand in response to a varying price. The report will use the more neutral term, "time-varying" prices.

There is no single list of AMI technologies and functions. New technologies and applications for AMI technology are rapidly being developed and brought to market. Some AMI proponents argue that there are uses for AMI that we have not even imagined yet, and whose benefits will far outweigh the costs of AMI installation.

For example, a number of technologies exist for performing the network communications functions, including power line pulse signaling, fixed wireless, internet signaling, and others. A regulator may be called upon to choose between particular technologies or even competing vendors. On the one hand, approving any particular form of AMI or any given source of AMI components provides some certainty about the scope of the AMI investment. A less prescriptive approach may make up in flexibility for the uncertainty of a specific AMI product's ultimate usefulness. In this regard, the California PUC has stated a preference for "open architecture" meters, which can "be accessed through multiple technologies such as radio and telephone."[16]

3. What AMI is Not: AMI vs. AMR vs. DLC vs. Smart Thermostats vs. PCTs

It is useful at the outset to note what AMI is *not.* AMI includes advanced metering (in particular, so-called interval meters, capable of recording and storing usage data at hourly intervals, if not at intervals as short as every 15 minutes). A utility can install interval meters, however, without installing an entire advanced metering infrastructure.

Some interval meters support static TOU pricing by means of a device added to the ordinary non-interval meter that allows the utility to collect usage information hourly. The utility then downloads the data monthly. AMI meters, by contrast, are also capable of sending and receiving meter and other data when called upon to do so, rather than merely storing it for monthly retrieval.

AMI is sometimes confused with "AMR," the acronyms being so close. AMR refers to automated meter reading, which in turn typically means remote meter reading, as by a hand-held device or a device on a utility truck driven by the meter location, picking up a signal from the meter to record the usage. AMR does not have to involve interval metering – the customer still could be paying a traditional, constant rate with the metering measuring only total usage in a month without regard to usage at particular times of day. Nor does AMR imply a two-way communications system and a meter data management system (MDMS). AMI, in contrast, can enable remote meter reading; in fact, the meter can be read from a central data storage and management location, by reading the signals communicated over the AMI network.

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[14] The "critical peak" consists of the small number of hours during a year during which most or all available generation resources are needed to meet demand.

[15] California's standard flat-rate electricity price design for residential customers is an inverted block rate, with five blocks, or tiers.

[16] Advanced Metering Final Decision, 19.

Direct load control (DLC) is another demand response tool that can be implemented using parts of an advanced metering infrastructure, but that does not require AMI. A utility can implement DLC using technology other than AMI. With direct load control, a customer agrees to allow the utility to turn off or down one or more end-uses at the customer's premises. Utilities and residential customers typically use DLC to cycle off air conditioners, using a radio or power line frequency signal sent to a device attached to the air conditioning control unit in the home. They also use DLC to reduce peak demand from pool pumps and water heaters. DLC is defined in the FERC Staff Report as follows:

> A demand response activity by which the program operator [the utility, typically] remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, water heater) on short notice. [17]

Utilities can use AMI as a convenient network to signal DLC devices at times of peak demand, but AMI is not required to perform this function. Utilities can set up a dedicated communications network to connect their control center with those customers taking service under a DLC rate; they need not implement an advanced metering infrastructure for all customers in order to provide DLC for some. Conversely, a utility can install AMI without installing direct load control devices on customer end uses.

Finally, "smart thermostats" are not a required component of AMI, although they may offer benefits for demand response in addition to those possible with AMI alone. "Smart" or "programmable communicating thermostats" (PCTs) are the devices attached to the air conditioner or other end use that receives signals from the utility. In a DLC program, the supplier signals the smart thermostat to lower or raise the end use device's draw on the electricity system. The signal could also be a notification of the beginning or the end of a high-cost peak period. The customer can pre-program the thermostat to respond to such signals, as by raising the temperature setting, or cycling the air conditioner off. For a customer to receive demand response signals from AMI's communications network, she would need (a) the interval meter networked to a load control or signaling system, and (b) a PCT attached to the end uses she wanted controlled.[18]

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[17] *FERC Staff Report*, Appendix A (Glossary)

[18] Readers should be also aware of so-called "gateway" devices, which act somewhat like routers by taking the pricing signals from the utility, then distributing those signals over a home area network (HAN) to various end uses in the house, permitting each end use to respond according to the instructions pre-programmed by the customer into the associated PCT or similar smart device. PG&E has recently asked the California PUC for approval of cost recovery for the installation of gateway devices and HAN technology. See *PG&E Upgrade Application*.

II. The Structure of an AMI Cost-Benefit Analysis

A. A cost-benefit analysis for AMI has the same analytical components as a cost-benefit analysis for other major utility investments

To justify an AMI investment, like any other investment, a utility will have to show that the investment will lead to lower costs, or to improved services, or both, relative to no investment and relative to alternative investments. The value obtained from the investment must at least exceed the cost, and must exceed the value of alternative investments.

A utility may present to the Commission its own internal business case for AMI. In a business case, the utility will limit the analysis to a comparison of the utility's costs of the investment versus the utility cost savings made possible by the investment and the improved value of service to the customers. In some jurisdictions, Commissions will also consider factors outside the business case, such as environmental or other benefits allegedly made possible by the investment.[19]

Whenever a utility seeks to reflect costs in rates, not only must the benefits of the particular investment decision exceed the costs, but the choice must be the best among a reasonable set of options available to the utility for the purpose(s) at the time. To make a case for AMI cost recovery, then, a utility will need to prepare information for the regulator demonstrating the following:

Figure IV: Elements of the Rationale for a Prudent Investment

1. The need or needs for the functionalities provided by the investment.
2. The array of reasonable alternatives available, including the one chosen, for meeting the needs.
3. The costs of each alternative.
4. The benefits of each alternative.
5. The relative costs and benefits of the alternatives compared.

As noted, the case for AMI will typically identify two primary needs for the AMI functionality: reducing costs of operation, and reducing the costs of meeting demand. Regulators should require the utility should be required to identify the scenarios it has identified and assessed for achieving these goals.

The types of costs and benefits included in a given jurisdiction's cost-benefit analysis will vary depending on the perspective from which the costs and benefits are measured. There

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[19] In California, three years after the end of the SPP, stakeholders are still debating what cost-effectiveness test or tests should be used to evaluate demand-response pricing approaches. Ahmad Faruqui and Ryan Hledik, *The State of Demand Response in California*, Draft Consultant Report, April 2007, at 18-19. Available at: www.fypower.org/pdf/CEC-200-2007-00**3**-D.PDF.

are five widely recognized cost/benefit perspectives[20] for evaluating the merits of an electric system investment in demand-side resources:

Figure V: California Standard Practice Cost-Benefit Tests

1. Utility Cost Perspective
2. Participant Cost Perspective
3. Non-Participant Bill Perspective
4. Total Resource Cost Perspective
5. Societal Cost Perspective

The elements of a benefit/cost analysis of demand response will vary depending on the perspective used to identify the benefits and the costs counted.

B. AMI is a major investment

AMI involves changing out 100 percent of residential and small commercial meters, replacing them with more expensive meters, installing a system-wide communications network, developing a new meter data management system, and rewriting software and business operations protocols to make optimal use of the new data and operational capabilities. While reliable estimates of the per meter cost for a full advanced metering infrastructure are hard to obtain,[21] estimates of AMI costs range from $110 per meter on the low end up to as much as $525 per meter. Plexus Research, Inc. developed an estimate for Edison Electric Institute (EEI) of the cost of various parts of an AMI implementation, pegging the per meter cost at between $200 and $525, depending on the functionality included:

> AMI costs ... typically include the following elements: AMI system hardware and software, new meters and meter-related utility equipment and labor, installation management and labor, project management, and IT support and integration. Costs for automated remote meter reading are approximately $100 to $175 per meter. Adding demand response

[20] California Public Utilities Commission and California Energy Commission. California Standard Practice Manual: Economic Analyses of Demand-Side Programs and Projects, October 2001, available at: http://www.cpuc.ca.gov/static/industry/electric/energy+efficiency/rulemaking/resource5.doc.

[21] One utility's consultant noted recently that much of the data on AMI component costs is proprietary, making it difficult to develop cost estimates that can be presented to a regulator, and the soundness of which a regulator can assess. Redacted Testimony of Dr. Gary Fauth, MW Consulting, on behalf of Central Maine Power Company, *Central Maine Power Co.: Chapter 120 Information (Post ARP 2000) Transmission and Distribution Utility Revenue Requirement and Rate Design and Request for Alternative Rate Plan*, ME PUC Docket No. 2007-215, May 1, 2007, at 5, 23.

components (e.g., customer signaling, load control, other demand response equipment) adds another $100 to $350 per site.[22]

For a system with 500,000 residential meters, then, the net present value cost of an AMI investment would likely fall in a range between $100 million and $262 million, net present value.

Pacific Gas & Electric (PG&E) plans to spend over $3 billion (net present value over twenty years) to implement AMI for its 9 million gas and electric meters. This investment represents an estimated cost of about $340 per meter.[23] The table below shows a breakdown of the costs PG&E estimated it would incur to install an AMI.[24]

Figure VI: PG&E Estimates of AMI Installation Costs

PVRR	Cost Category
$2.30M	Meters/modules QA; sample testing
$5.30M	Customer exceptions processing
$6.90M	Gas network and other installation
$22.60M	Marketing and communications
$43.40M	Other employee-related costs
$44.00M	Customer acquisition
$45.50M	Customer contact-related costs
$87.50M	Project management costs
$98.50M	Network materials
$99.10M	Electric network and Wide Area Network installation
$109.10M	Interval billing system
$119.10M	AMI operations
$129.30M	Meter operations costs
$135.00M	Risk-based allowance[25]

[22] Plexus Research, Inc., Deciding on "Smart" Meters: The Technology Implications of Section 1252 of the Energy Policy Act of 2005, Prepared for Edison Electric Institute, September 2006, at xii.

[23] PG&E Upgrade Application.

[24] PG&E Ex. 32, revised Table 10-1 (Revised 3/14/06), *PG&E AMI Final Opinion*, CA PUC Decision 06-07-027, July 20, 2006. As noted above, PG&E recently filed an "update" to its cost estimates, to include approximately $939 million in additional costs, on a present value basis. This update brings the total cost estimate to roughly $3.2 billion. *PG&E Upgrade Application*, at 1.

[25] The "risk-based allowance" is essentially a contingency allowance. *PG&E AMI Final Opinion*, CA PUC Decision 06-07-027, July 20, 2006, at 12. Decision available at: http://docs.cpuc.ca.gov/published/FINAL_DECISION/58362.htm.

PVRR	Cost Category
$155.60M	Interface and systems integration
$355.90M	Meters/modules installation
$799.20M	Meters and modules
$2,258.30M	**Original Total Estimated Project Costs**
$939.00M	Additional metering costs per *Upgrade Application*[26]
$3,197.00M	**Revised Total NPV Costs**

As can be seen, the cost of the advanced meters themselves, together with their installation, is about two-thirds of the total estimated cost of AMI for PG&E:

$800 million for meters and modules, plus
$940 million NPV in additional metering costs and related expenses, plus
<u>$355 million in meter installation costs, for a total of</u>
$2.1 billion out of the $3.2 billion total NPV estimated

Southern California Edison has estimated it will cost just under $2 billion to implement AMI in its service area, resulting in a per-meter cost of about $370.[27]

Not all experts in AMI are convinced the utility estimates represent the necessary costs of AMI investments. Stephen George and Michael Wiebe presented a lower-end cost estimate in a workshop presentation in August 2007. These consultants estimate the total capital cost per meter of an AMI installation will range from $110 to $130 per meter, with operating costs at 35 cents per month.[28] They note that the costs of advanced metering vary with the technology chosen, customer density, and other factors. Dr. Gary Fauth, testifying for Central Maine Power Company in its pending request for AMI cost recovery, stated that per-meter AMI costs from three other utilities (PPL, PG&E, and Bangor Hydro-Electric) ranged from $124 to $150 per meter.[29] Roger Levy also has noted that municipal AMI investments have been considerably less

[26] Such additional costs mainly relate to an additional $565 million capital investment in solid state advanced meters fitted with remote connect/disconnect switches, and installation of home area network (HAN) gateways. *PG&E Upgrade Application*, at 3-4.

[27] Most published cost estimates range between $100 and $200 per meter, but it is important to look at the specific proposals in any given case, to make sure that all costs are included in the estimate.

[28] Stephen S. George and Michael Wiebe, *Benefit-Cost Analysis for Advanced Metering and Time-Based Pricing*, Workshop, August 21, 2007, at 6. George and Wiebe state that typically less than half the costs of AMI are for the meters themselves. George and Wiebe do not include the incremental information technology investments that are needed for large-scale use of demand-responsive rates.

[29] Redacted Testimony of Dr. Gary Fauth, MW Consulting, on behalf of Central Maine Power Company, Central Maine Power Co.: Chapter 120 Information (Post ARP 2000) Transmission and Distribution Utility Revenue Requirement and Rate Design and Request for

costly than the utility estimates gathered here.[30] Levy also points out that AMI can be implemented without billing changes or DR program functions, in which case back office software changes or additions will not be as extensive nor as costly as those proposed by PG&E, for example. On the other hand, to the extent that a utility invests in AMI lacking the ability to support tariff changes, associated billing changes and demand response functionalities, a major potential source of benefit from the investment is presumably foregone.

C. AMI can provide large operational cost savings to a utility

1. Most operational savings come from replacing labor with information technology

One of the largest sources of cost reductions made possible by AMI is operational savings. The operational savings come in a number of forms:[31]

Figure VII: Categories of AMI Operational Savings

1. Remote meter reading
    a. Eliminates need for meter-reader to read meters
    b. Allows more frequent meter-reading
    c. Eliminates problems associated with estimated bills
    d. Improves meter reading accuracy, thus reducing meter disputes
2. Remote disconnection/reconnection (electric only)
3. Identification of outage locations
    a. Supports more rapid customer restoration time
    b. Eliminates need for customer outage reporting
    c. Allows more accurate dispatching of repair crews, with associated cost reductions
4. Improved tamper detection
5. Improved capacity utilization
6. Grid voltage and phase monitoring
7. Better load data for planning purposes

Alternative Rate Plan, ME PUC Docket No. 2007-215, May 1, 2007, Table GF-1, at 4. It is not possible, based on the information readily available, to square Fauth's estimate of PG&E AMI costs ($135 per meter) and the $340 per meter estimate derived by dividing the total net present value cost estimate of $3.2 billion by 9 million PG&E meters (or even the $250 per meter estimate that would result from dividing PG&E's earlier $2.3 billion cost estimate by its 9 million meters).

[30] Email from Roger Levy, January 30, 2008, with comments on draft report.

[31] See *In the Matter of the Commission's Combined Consideration of the Utilization of Advanced Metering Technologies Under 26 Del. C. § 100(B)(1)B. and the Implementation of Federal Standards For Time-Based Metering and Time-Based Rate Schedules Under 16 U.S.C. §§ 2621(D)(14) and 2625(I), Advanced Metering Report to the Delaware Public Service Commission*, prepared by Delmarva Power & Light Company, Division of the Public Advocate, and the Delaware Public Service Commission Staff, November 15, 2006, at 7.

In its recent AMI business case filing in Delaware, Delmarva Power & Light Co. (Delmarva) estimated that, depending on the size of expected demand response from time-varying pricing, the operational benefits of its proposed AMI implementation would be as much as 77 percent of the total savings it forecast, and at least 53 percent.[32] Before proposing to install an AMI with greater functionality, Pacific Gas & Electric Company estimated that almost 90 percent of its AMI investment would be recovered through operational benefits (the proportion may be closer to 2/3 with the added cost). Southern California Edison and Sempra estimate that they will recovery roughly 50 percent of their AMI costs through operational benefits.[33]

2. AMI permits service quality improvements

Many of the functionalities that AMI makes possible not only save a utility in operational costs, but also improve the quality of service provided to customers. For example, more frequent meter-reading gives customers better information on their changing usage and electricity costs, in turn making it easier for customers to budget for such costs. Similarly, by eliminating the need for estimated bills, AMI makes it possible for customers to have timely and accurate readings of their actual usage, and receive bills that do not require adjustment. This accuracy in turn helps with electricity cost budgeting. Estimated bills also create many billing disputes that are not only costly to the utility, but aggravating and time-consuming for customers. More timely and accurate meter readings should also remove a common source of distrust of the utility by consumers.

Identifying outage locations, dispatching crews more efficiently, and restoring customers more rapidly would provide an enormous benefit to consumers. As regulators are well aware, outages, slow restoration time, and lack of good information regarding outage time is a source of considerable frustration to consumers.

Improved tamper detection helps protect those whose electricity is being stolen.

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[32] *In the Matter of Delmarva Power & Light Company's Blueprint for the Future Plan for Demand-Side Management, Advanced Metering, and Energy Efficiency*, Report for Delaware: Advanced Metering Business Case Including Demand-Side Management Benefits, filed August 29, 2007, Del. P.S.C. Docket No. 07-28. It is axiomatic that the higher the assumed demand response resource benefits, the lower the percentage the operational savings represent of the total benefits.

[33] *Ibid*. The differences in the percent of savings attributable to different utility operations is likely due to differences in the cost of these functions to each utility using existing resources (largely labor). Staff of the California Public Utilities Commission, Division of the Ratepayer Advocate analyzed why PG&E estimated AMI operational savings at levels much higher than those forecast for comparable operational changes with AMI by San Diego Gas & Electric. Among other things, the analyst observed, labor costs at PG&E were significantly higher, and avoiding those costs accordingly brought PG&E a larger benefit than was the case for the Southern California utilities. Marshall Endberry, *Meter Reading Benefits,* Division of Ratepayer Advocates, Chapter 7, available at: http://www.dra.ca.gov/docs/electric/SDGandE/A0503015_Ch7_MeterCost.pdf.

Grid voltage and phase monitoring should lead to improvements in voltage stability and distribution reliability. Better load data for planning purposes will give the public information they can use to participate in the great debates under way today regarding the kinds of investments needed to meet electric power needs going forward.

3. Different utilities have different operational savings and benefits

The lion's share of AMI operational savings comes from eliminating labor costs for meter-reading. This result is consistent across the utilities that have filed business cases with their commissions. The existence and relative amount of other benefits appears to vary from utility to utility.

For some utilities, the second-highest savings come from eliminating labor costs for connection, disconnection, and reconnection. On the other hand, utilities in Oregon considering the implementation of AMI have advised the Oregon Commission that they do not consider remote disconnection/reconnection cost-effective for their systems.[34] Pacific Gas & Electric in California forecasts remote turn-on/shut-off functionality to produce 5 percent of the total operational cost reductions from implementing AMI. Utilities thus have provided regulators with widely varying estimates of the cost savings available from the elimination of manual connection and reconnection of metered premises.

Improved billing accuracy and timeliness, reducing off-cycle meter reading costs, and allowing asset optimization together produce savings taken together that are large enough to have a noticeable impact on AMI cost/benefit calculations. Other operational benefits together make up a smaller percentage of the total savings attributable to the substitution of AMI technology for labor costs. The exact distribution of estimated operational cost savings will vary from utility to utility.

[34] Email to Consumer Affairs listserv from Phil Boyle, Manager, Customer Services and Information, Oregon Public Utilities Commission, October 25, 2007.

The table below shows how two utilities identify the share of major AMI savings associated with different functions:

Figure VIII: Major Categories of Operational Savings, Two Utilities

Major Categories of Operational Savings, As Estimated By Two Utilities[35]

Benefit Category	**% of Total Operational Savings**	
	Utility A	**Utility B**
Eliminate manual meter-reading costs	53%	60%
Electric Transmission and Distribution	10%	3%
Meter Operations	5%	n/a
Reduce Customer Contact Costs	2%	1%
Improved billing accuracy/timing/reduce theft	11%	9%
Reduced software license, hardware expense	2%	1%
Remote Turn-On/Shut-Off	5%	25%
Other Employee-Related Costs	11%	n/a
Reduced Equipment Replacement Costs	1%	n/a

The two utilities in the example forecast that over half the expected operational cost savings will come from eliminating manual meter reading costs. A utility's present costs, and thus its potential savings from AMI, will likely vary from utility to utility. Nonetheless, the estimates provided by the two utilities in the above example give a good sense of the type of information on operational benefits that a utility is likely to present in a business case for AMI.

4. Operational savings sometimes come at a cost to the customer

When is a benefit not a benefit? Critics of AMI argue that the ability to disconnect a customer remotely, without the opportunity for personal contact when a technician comes to the home to disconnect the meter, denies customers an opportunity for personal intervention that otherwise exists.[36] It thus puts particularly vulnerable customers at greater risk. Some states

[35] One of the utilities whose estimates are reflected in this chart is PG&E, and the other is a utility on the East Coast, information as to which was derived from data in a confidential filing. To ensure that no confidential data is revealed, the specific identities of the two utilities are withheld, and only percentage contributions to overall savings are shown.

[36] A director of consumer affairs for one Northeast state public utilities commission noted in an email listserv discussion of the issue in October, 2007, that her commission relies not only on in-person disconnection, but in-person meter reading as well, as a tool to ensure that shut-ins and other vulnerable customers have human contact with their utilities providers at least once a month.

require an electric utility to attempt an in-person notification of impending disconnection, whether to provide an opportunity for the customer to remedy the default and prevent disconnection, or to alert the utility to the possibility that the customer has been unable to understand and respond to collection efforts, and will be put at risk by a disconnection.[37]

For example, New York State by law prohibits remote disconnection, even of electricity, and requires that utilities allow customers to pay their bills at the time of disconnection to prevent the disconnection.[38] The New York Public Service Commission has recently pointed to this statutory "last knock" provision in orders denying immediate approval of AMI proposals by two electric utilities in the state.[39] Similarly, the Michigan Commission requires more than one telephone notice attempt, and phone lines must be disconnected in person.[40]

The requirement of in-person contact is by no means universal today, however. Indeed, recently promulgated AMI rules in Texas require that the utility have the ability to perform remote disconnection.[41] Utilities in Idaho and Iowa have filed proposals to institute remote disconnection.[42]

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[37] Remote disconnection and reconnection is not safe in the case of gas utilities. Disconnection results in the pilot light on appliances and furnaces going off; if the gas is restored without the pilot light gas source first being turned off, gas can build up and when the pilot is lit, an explosion can result. Gas utilities send a trained technician to perform disconnections and reconnections, to avoid such accidents. The inability to use remote connection and disconnection in the case of gas utilities is a key reason why the economics of AMI are different between gas and electric utility applications.

[38] See New York Public Service Law, Article 2, Section 3(b) and (c).

[39] PULP, *PSC Requires More Study Before Allowing Major Investment in "Smart Meters,"* January 11, 2008, available at: http://www.pulpnetwork.blogspot.com/.

[40] Recently a 90-year old Michigan woman died of hypothermia, and her mentally disabled 65-year old daughter suffered frostbite, when their electricity was disconnected this winter. The Commission and the utility are investigating whether the customer received in-person notification, as required by Commission. According to the dead woman's family, she had become more forgetful recently; she had apparently forgotten to pay her bills, although she had sufficient funds. Preventing such tragedies is one reason why some Commissions require in-person disconnection. The Associated Press, "Utility looks into death of Vicksburg woman, 90, after power shut off," originally published January 2, 2008, available at: http://www.battlecreekenquirer.com/apps/pbcs.dll/article?AID=/20080102/NEWS01/301020015/-1/bb.

[41] 16 Texas Administrative Code §25.130(g)(1)(D)**,** published November 10, 2006, for effect May 10, 2007, pursuant to Public Utility Regulatory Act (PURA) §39.107 as amended by House Bill (HB) 2129, 79th Legislature, Regular Session (2005).

[42] Iowa's proposal would include the ability to impose a service limiter on an account, as permitted by Iowa Administrative Code, § 20.4(23).

Utilities promoting remote disconnection/reconnection argue that, despite the claimed importance of in-person contact, customers generally will benefit as the utility will be able to reconnect service more quickly using AMI technology, and will be able to reconnect during non-business hours, an expensive proposition with in-person reconnection. Resolution of this issue is a policy decision regulators must make. There is little data on the extent to which avoided disconnection and reconnection costs would be associated with foregoing "last knock" opportunities for vulnerable customers to avoid disconnection.

D. Customers can reduce system resource costs by reducing demand, especially at times of high system demand

Section C dealt with operational cost savings. In this subsection we turn to resource savings attributable to demand response.[43]

While some utilities have implemented AMI without implementing time-varying pricing or other demand response initiatives, for most utilities it is likely that operational cost savings (even coupled with the value of improved services) will not cover the full cost of an AMI investment. Utilities point to additional cost savings that they can obtain by using AMI to support time-varying prices, which are intended to induce customers to reduce demands at times of high system costs, thus lowering system resource costs.

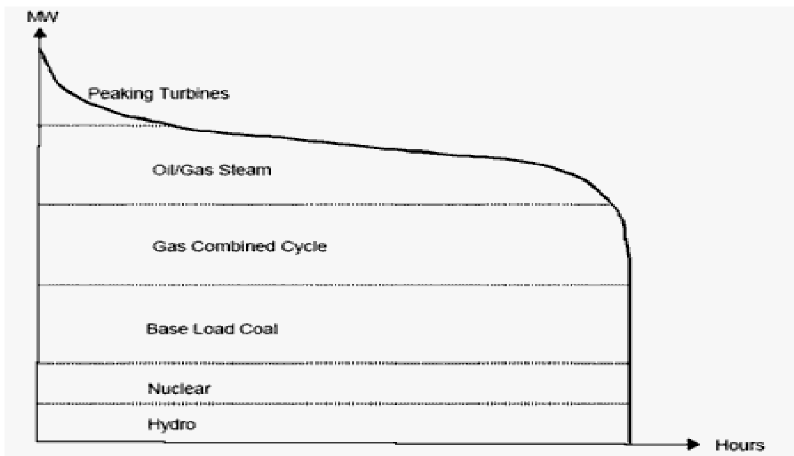
By "resource costs," we mean here the various costs associated with the production function: generation capacity and energy costs, and transmission and distribution capacity costs. Some states include externality costs such as emissions[44] in their determination of resource costs, and some states include customer demand response and non-utility generation as system resources.

[43] Traditionally, utility analysts would not use the term "resource costs." Costs associated with meeting customer energy and capacity needs were broken down by the various utility functions, such as operations, maintenance, transmission, distribution and generation. Since the late 1980s, regulators and utilities in a number of states have adopted the term "resource costs" to identify not only these utility costs, but costs incurred by others to meet customer needs. Sometimes these additional costs include externalities such as environmental or social costs.

[44] There is an ongoing debate among analysts as to whether demand response initiatives create environmental benefits such as reduced emissions. Prominent advocates of demand response as a tool to foster environmental benefits acknowledge that reducing peak demands can actually increase emissions in certain situations. For example, in systems with gas or hydro plants at the margin, and coal as the baseload fuel, backing off the cleaner peak fuels increases the proportion of kilowatthours served with more polluting coal generation. David Nemtzow, Dan Delurey and Chris King, "The Green Effect: How demand response programs contribute to energy efficiency and environmental quality," *Public Utilities Fortnightly*, March 2007, at 44. Estimating the change in emissions from demand response requires careful analysis of the specifics of each situation.

The primary resource cost that can be deferred or avoided via persistent AMI-supported demand response is the cost of incremental generation capacity.[45] Looking at an annual load duration curve, one can see that there is a small number of hours when load is quite low (such as the hours during the dead of each night), a large number of hours in the year when there is a steady demand for power, a large number of hours with a varying amount of load above the base, and a very small number of hours when the system is running at or very near its maximum capacity. The drawing below[46] shows a hypothetical load curve of a utility with several types of generation, indicating the hours in the year the different plants are likely to be dispatched, given their cost characteristics. As can be seen, the portion of the year when peakers are brought on line to meet peak demand is quite small:

Figure IX: Annual Load Durations, w/Plant Dispatch Periods by Generator Type



To meet base load needs, utilities select plants with low running costs, albeit high capital costs. The utility will run these plants 24 hours a day, most days of the year. It is usually less expensive to do so than to run plants with lower capital costs, but higher operating costs, for such extended periods.[47] For the hours of highest demands, the peak hours, a utility will build a plant with high operating costs, but low capital costs. Such "peakers" are more cost-effective for the purpose of meeting demand during a few hours of the year while sitting idle the rest of the time.

[45] See, e.g., *The Power of Five Percent*, and In the Matter of Delmarva Power & Light Company's Blueprint for the Future Plan for Demand-Side Management, Advanced Metering, and Energy Efficiency, Report: Quantifying Customer Benefits from Reductions in Critical Peak Loads from PHI's Proposed Demand-Side Management Programs, prepared by the Brattle Group for Pepco Holdings, Inc., filed September 21, 2007, Del. P.S.C. Docket No. 07-28.

[46] This chart was copied from http://www.ec.gc.ca/cleanair-airpur/caol/canus/IPM_TECHNICAL/ipm_technical_report/images/figure2_3_e.gif.

[47] The breakpoint between load levels most economically served by different types of plants will vary with the particular system and its loads, but all systems were historically built along these general lines to minimize unit costs.

For loads in between these two extremes, planners select so-called "intermediate" plants, whose relative capital and running costs are less skewed than either baseload or peakers, and which can be turned on and off as needed to follow changing load requirements at the least cost to the system.

System operators dispatch plants in order of unit production cost to meet growing or declining load. The higher the load on the system, the higher the cost per kilowatthour of the plants brought on line. Dispatching plants according to their relative unit costs of operation is called "merit order" dispatch. The objective is to minimize the total cost of supplying power to meet the changing demands on the system over time.

Note that the situation is slightly different in the case where a regional transmission organization (RTO) or Independent System Operator (ISO) performs the dispatch function according to the results of an energy market. In such a system, plants will not be dispatched in "merit order" (i.e., on the basis of their cost to the unit owner). Rather, aside from "self-scheduled units" that are dispatched at the request of the owner (and that are not bid into the energy market for the hour in question), the RTO/ISO dispatches all units whose bids were less than or equal to the market-clearing price.[48] The suppliers, optimizing their portfolios in response to incentives created by an energy market (and perhaps a capacity market and markets

[48] If an RTO/ISO system does not have as much demand in the particular hour as the system operator assumed when it cleared the market (and thus determined which plants would be dispatched), and does not need generation from the plant whose bid determined the market clearing price, the system operator resets the market clearing price to the level of the next lowest bid (which is now the highest bid of those needed to run in that hour). Should the system in the particular hour require more resources than those the system operator forecast when it ranked the bids and thus selected the units to be dispatched, the RTO/ISO must acquire additional resources for reliability purposes. Under the Standard Market Design (SMD) used by the major RTOs and ISOs to run their markets, the system operator selects such additional generation as follows:

> Generation offers and load bids into the Day Ahead market. The Day Ahead Market clears to minimize total cost to serve load plus reserves, much like the day ahead commitment under the interim markets. However, since the Day Ahead Market is voluntary and financial, not all load may bid into it, consequently, there may not be enough capacity on-line to assure reliable operation.
>
> To assure reliability, the ISO performs a Resource Adequacy Assessment. The objective of the Resource Adequacy Assessment is to assure sufficient capacity is on-line (or off-line and available) to meet load plus reserves. If additional capacity is needed to meet reliability the ISO does not commit based on energy economic merit order. Instead, the ISO commitment is based on minimizing the costs of bringing a unit on-line.

Source: ISO-NE Frequently Asked Questions available at: http://www.iso-ne.com/support/faq/other/why_is_my_unit_not_running.pdf for ancillary services), tend to bid into the energy market in such a way that the resulting dispatch looks similar to a merit order dispatch, but it will not be identical.[49]

The exact amount, sources and relative share of savings from lowering incremental demand will vary from state to state and region to region, depending on such factors as the extent to which capacity is available to meet forecast demands, and the mix of plants and fuels used to generate power in the area.

Published estimates of demand-related resource savings also depend critically on assumptions about how many customers will respond to price signals, to what extent and for how long. The state of our understanding of the extent of and persistence of demand response to dynamic pricing is the subject of Section III.

The method analysts typically use to estimate avoided costs is a standard avoided cost calculation. Note, however, that in retail competition systems, where most electricity customers receive their power under standard offer service provided by suppliers under contract, the avoided system costs will not translate into reduced prices in the short term, unless the contracts specify that savings from demand response programs are somehow identified and flowed through to customers.

In addition, demand responses must be reliably persistent over time, or planners and market overseers will not reflect them in the development and pricing of new generation capacity. In New England, for example, ISO-NE establishes the Installed Capacity Requirement (ICR) for the entire region for a specific "power year" approximately 3 years in advance of that power year (e.g. in 2007 it sets ICR for 2010).[50] This overall capacity requirement is not affected by events in the next two years, unless they are part of a reliable pattern that planners can take into account in their forecasts of loads and resources. A load serving entity (e.g. a utility) can reduce its proportionate share of the regional ICR if its loads in the year before the power year in question are lower, relative to the loads of other LSEs, than they were before. This adjustment, however, only occurs if other LSEs do not induce their customers to reduce loads proportionately, and in any event does not relieve the region as a whole from the ICR set two years earlier.

Similarly, the market value of capacity avoided by demand response will be effectively zero, unless the capacity reductions are persistent. Estimates of market price reduction assume that reductions in peak load by a limited number of participants in a demand-response program will result in a lower market price for capacity, which in turn will benefit all consumers. In order

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[49] These differences in likely dispatch patterns and associated supplier cost recoveries will affect the economic value of demand response, but likely not enough to change the analysis of the value of AMI. Our discussion here will use the example of a vertically integrated electric utility, owning and generating most of its own plant. The analysis can be adapted to the electricity market situation, but it will be easier to highlight the issues of interest here if we focus on the simpler case.

[50] Email to author from Rick Hornby, Synapse Energy Economics, January 31, 2008.

for the load reduction from the participants to cause the FCM to "clear" at a lower price, however, the planners at the regional transmission organization need to "see" enough years in which those actual load reductions occur to cause their econometric model to forecast a lower peak demand than it otherwise would.

The need of a regional transmission organization with a forward capacity market to set capacity requirements some years in advance, and to price that capacity, creates a need to establish the reliability of anticipated demand reductions. As Hornby explains, estimating the timing and magnitude of the market price reduction benefit requires some care. The planner in a vertically integrated system has a similar obligation to forecast reliably, so as not to underestimate the power requirements in future years. One can argue that the persistence of demand responses into the future is subject to no more uncertainty than the likelihood of demand growth over the same period, but whereas econometric models for forecasting demand have become commonplace, system planners and market operators have not had as much experience forecasting demand response, and calibrating their forecasts to improve reliability.

1. AMI can be used to support time-varying pricing and other demand response programs

There are a number of tariff designs intended to match unit prices of electricity to system costs at the particular time of use:

Figure X: Time-Varying Pricing Options for Residential Customers

1. Pure Critical Peak Pricing ("CPP")—time varying pricing on high-demand days only;

2. Pure Peak Time Rebate ("PTR")—a pay-for-performance offering that pays customers a certain amount for each kWh not used during peak periods on high-demand days;[51]

3. Critical Peak Pricing/Time of Use ("CPP/TOU")—time varying prices on both high-demand and other weekdays, with the highest prices occurring on high-demand days;

4. Time of Use ("TOU")—the same time-varying prices on all weekdays for a season or year;

5. Real Time Pricing—prices that change hourly in response to market conditions.[52]

[51] Peak Time Rebate is the current term—in the pilots, PTR was typically referred to as Critical Peak Rebate, or CPR.

[52] This list is taken from the rebuttal testimony of Stephen S. George , Ph.D. on behalf of Central Maine Power Company. *Central Maine Power Company: Request for New Alternate Rate Plan*, Maine PUC in Docket 2007-215, at 9-10.

A utility may use AMI to support a variety of pricing and other demand-response initiatives to induce customers to lower their usage at particularly high-cost hours.[53] Interval metering, a core component of AMI, allows a utility to charge different prices for electricity used at different times. A utility can use AMI to offer dynamic prices in addition to static TOU rates. A dynamic price is one that a utility can change in real time, or close to real time, to respond to changing system conditions. In theory, at least, a utility can use the two-way AMI communications network to signal the customer when the price changes, and to give advance notice of the change. Without AMI, utilities give signals over dedicated networks, by radio, power-line carrier and even by phone, fax, and email.

In addition to time-varying pricing, a utility can support other demand response programs using AMI. The two-way communications network included in AMI provides a system by which the utility can signal a customer's meter-designated end-uses (such as central air conditioning), instructing them to cycle off or use less power during the high-price period. The utility can use the same communications network to signal that the particularly high-price period has ended.

It is important to stress that utilities can—and have—supported such direct load control demand response programs without AMI. Demand response programs are related to AMI only inasmuch as they need and use interval data, and as the utility chooses to use the same two-way communications network it has installed as part of AMI to signal customers or their end-use devices as part of its DR tariff or program. AMI and DR are separate systems. AMI and technologies for signaling the customer are not necessarily parts of the same system, nor do they need to be physically linked.

2. AMI allows utilities to offer prices that more closely match changing system costs

Utilities and planners have offered customers (even residential customers) so-called Time of Use (TOU) rates[54] for many years. Ordinary TOU rates typically define two or three pricing periods during a day: peak and off-peak. Then prices are set to approximate the estimated costs of usage during the given periods.

Utilities, sometimes at the behest of the regulator, introduced such time-of-day Peak/Off-Peak TOU pricing for residential customers in the 1980's, at the time of the energy crises of the

[53] Again, AMI is not necessary in order to implement a variety of forms of time-varying pricing. It is "sufficient" but not "necessary."

[54] Some analysts would include in the definition of Time of Use rates any rate that varied in unit cost depending on any measure of time, including seasonal rates, for example. Seasonal pricing is a form of demand response pricing. Seasonal pricing does not require advanced metering of any kind, but by the same token, it follows cost differentials in only a crude fashion. In this memorandum, we will restrict the use of the term Time of Use rates to tariffs in which prices change within a 24-hour period (technically, diurnal TOU rates).

day. Residential TOU rates eventually fell into disuse, in part because of public opposition,[55] and in part for lack of customer interest.[56] Long on-peak periods (sometimes as long as 12 hours) dampened customer interest. But the energy challenges facing society today, coupled with reduced interval metering costs due to evolving technology, have given new impetus to the effort to promote time-varying prices.

A utility today can implement narrower pricing periods than it could cost-effectively using earlier technology. This greater precision is valuable in pinpointing the times when changes in usage can bring the greatest changes in system costs. The ratio of cost reductions achieved for load reductions experienced becomes higher as the system nears its overall peak. The pricing approaches used to incent demand reductions thus focus on peak usage. The utility can use the AMI network to give customers notice a day in advance or even a few hours in advance of a particularly high-cost ("critical peak") period, and to signal its end. Prices for such narrow periods can be set to match the costs of such narrow periods.

Off-peak prices in a TOU tariff are lower than the standard flat rates. As a result of the differentiation of prices by time of usage, a customer with relatively lower usage on peak than the average will enjoy lower overall bills on TOU rates than on the underlying flat rate, assuming no change in time of usage. Conversely, a customer with a higher relative on-peak usage than the average for the class will see higher bills on TOU rates, unless the customer can move usage off that peak time period.

By more narrowly defining the high-priced periods, utilities can offer customers time-varying prices with shorter periods of very high prices. This approach has the benefit of greater convenience and customer acceptance than traditional TOU prices with broad peak periods. To take advantage of these improvements in tariff design, utilities are increasingly offering so-called critical peak pricing.

Critical peak pricing (CPP) is a form of TOU pricing. Under critical peak pricing, the price for power is as much as 5 or 10 times higher during the critical peak than during other times, while the price is correspondingly lowered during the remaining 80 percent to 90 percent of the hours. Not every day will have a critical peak. The critical peaks are those few hours[57]

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[55] See Kenneth Gordon, Wayne P. Olson, Amparo D. Nieto, *Responding to EPAct 2005: Looking at Smart Meters for Electricity, Time-Based Rate Structures, and Net Metering*, prepared for Edison Electric Institute, May 2006, at p. 7, n. 12.

[56] Ralph E. Abbott, "Time-of-Use Rates: Sideburns and Bellbottoms?," *Energy Markets*, July/August 2005, pp. 6-8.

[57] At least for residential customers, utilities have generally not attempted to price power differently for time periods shorter than a couple of hours, although the technology of advanced metering theoretically could enable a utility to define a separate price for periods as small as 5 minutes. Several utilities in Washington State recently completed a pilot demand-response program in which price signals were given every five minutes, and a customer's present willingness to pay given amounts for designated "comfort settings" determined the customer's demand response. See note 204, below.

during the year when system load is at its highest, and the system is strained to its maximum capacity. A utility will notify customers on the CPP rate the day before or the morning of a critical peak event.

These peak periods represent a tiny fraction of the total hours in a year, but it may be possible to avoid significant resource costs if load can be shaved from or moved off of such times on a sustained basis over time. In most parts of the United States, the period of maximum electricity demand spans only 1 percent to 2 percent of the hours of the year. Put another way, "80 to 100 hours account for roughly 8 to 12 percent of the maximum or peak demand."[58] A critical peak tariff will define critical peak for pricing purposes as some subset of these hours.

There is no single definition of the critical peak periods. The designation varies by utility, and is determined not only by system resource requirements but also by rate design considerations (such as customer acceptance of a limited number of hours of very high critical peak prices). Critical peak events will typically be limited to a small number of hours in the day of the critical peak (e.g. 2 to 7 in the afternoon). CPP tariffs usually contain a limitation on the number of critical peak events and/or critical peak hours a utility may call in any given year (or season).[59]

As a variant on CPP, a utility can also offer critical peak rebates (CPR), sometimes called a peak-time-rebate, or PTR. Under PTR tariffs, a customer would be charged according to the same underlying tariff the typical customer of that class faces. However, the utility notifies the CPR customer of an impending critical peak, and the customer has the opportunity to reduce usage (relative to a defined baseline) during that critical peak, and receive a rebate for such reductions.

The most-often discussed CPR/PTR tariff calculates the rebate as the reduction in usage from the baseline times a rate equal to what would be the critical peak price for those customers on CPP rates. In the Ottawa Hydro CPR pilot, for example, the customer paid the ordinary 10.5 C¢/kWh TOU rate for all peak usage at or above the baseline during critical peaks. If the customer reduced critical peak usage 1 kWh per hour (*i.e.*, 1 kW) below the baseline for 3 critical peak hours, he would be credited with a rebate equal to 3 kWh times 30 cents, or 90 cents for that critical peak day.

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[58] Ahmad Faruqui, Ryan Hledik, Sam Newell, and Hannes Pfeifenberger, "The Power of Five Percent*," The Electricity Journal*, Volume 20, Issue 8, October 2007, at 69.

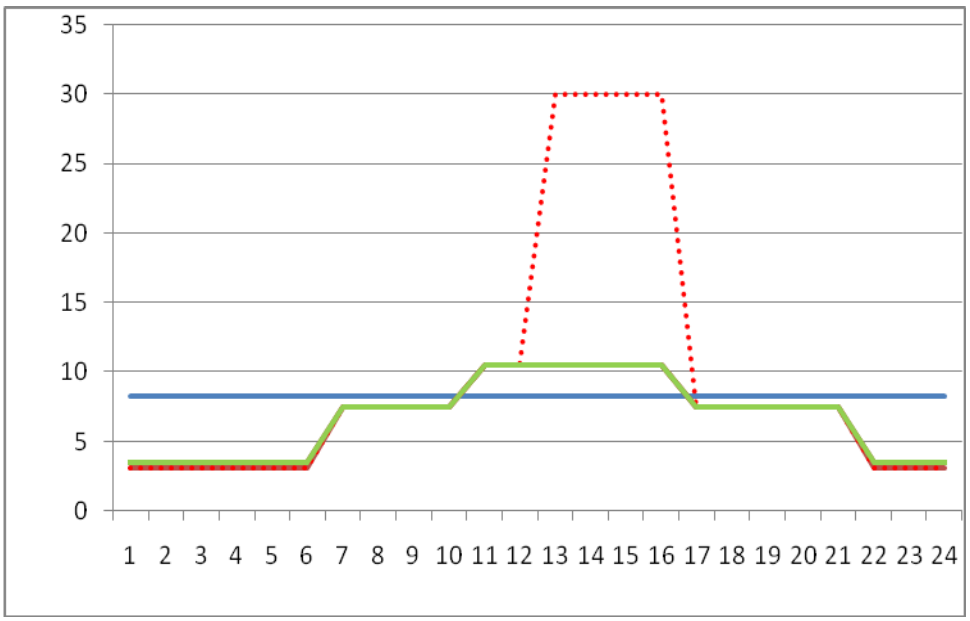
[59] Other versions of a critical peak tariff include Extreme Day Pricing (the critical peak price applies all 24 hours of the critical peak day; the number of critical peak days is limited, and the utility notifies customers the day ahead) and Extreme Day CPP (the critical peak price applies to the critical peak hours of the critical peak day, and the flat rate applies to all other hours of all other days – there is no TOU rate included). See Ahmad Faruqui, *Pricing Programs, Time of Use and Real Time*, Encyclopedia of Energy Engineering and Technology, 1:1, 1175 – 1183, available at: http://dx.doi.org/10.1081/E-EEE-120041453.

The picture below shows an example of critical peak pricing applied during a critical peak day. As the system is stressed by repeated days (and nights) of hotter-than-usual weather, unit costs approach their highest levels of the year. Under the Critical Peak Pricing tariff assumed in this example, the utility can call a critical peak event for the particularly costly hours on Wednesday and Thursday.

The picture gives a good sense of the differential between standard flat rate and Time-of-Use prices and CPP prices. During those critical peaks, per kilowatthour prices for customers on the CPP tariff are 6 times as high as the standard flat rate, and even 3 times as high as the peak rate on the standard TOU tariff. These extraordinarily high prices (e.g. 30 cents/kWh) are in effect for CPP customers for only a few hours on each critical peak day; the utility is typically limited in the number of critical peak events it can call. CPP customers, then, do not face these very high prices for more than 80 to 100 hours in the entire year.

Figure XI: Chart of CPP/TOU/Flat Rate Prices on a Critical Peak Day

Cents/kWh



Hours

The closer a utility can price usage for any given hour to the actual system costs incurred by customer usage during that hour, the more dynamic the rate. In the pilots described in Section III below, California has recently experimented with forms of critical peak pricing in which customers receive notice of the specific critical peak price on the day before or the day of the critical peak event, depending on the tariff. Commonwealth Edison and a Chicago neighborhood cooperative piloted a form of real-time pricing. Utilities in the Northwest have recently conducted a pilot in which participating customers were notified in real time (5-minute intervals) of changing price events, and engaged in a real-time market to determine the value of demand reductions (or the price of buying through) at the designated peak.[60]

III. Impacts of Time-Varying Pricing on Residential Customers

A. AMI analysts disagree over whether residential customers can benefit from AMI

Regulators considering a request for cost recovery of AMI are likely to have to resolve a number of disagreements between AMI proponents and AMI opponents. Some of these disagreements concern fact assertions. Some related to conclusions that different parties draw from the same facts. Finally, some disagreements relate to policy differences. In this section, we list the major areas of contention. In later sections, we examine the evidence available to resolve factual disagreements, and discuss policy implications.

1. AMI critics argue that residential customers will have bill increases, but that many will not be able to avoid high peak prices

Critics of AMI argue that implementation of an advanced metering infrastructure will increase costs for most residential consumers, without offering them a realistic way, through demand response, to avoid incurring those costs. The Utility Reform Network (TURN), a California consumer advocacy group, argues that low-use residential customers in particular do not have enough load to shift shifted away from the peak periods; thus they will pay for the meters but not get the cost reductions. Conversely, TURN argues, those with loads high enough to load-shift away from on-peak or critical peak prices will not bother to do so, because their high incomes enable to them to bear the cost of avoiding the inconvenience of load-shifting.[61]

Barbara Alexander, a noted consumer affairs expert, seconds these arguments. She makes the following assertions in support of her opposition to AMI and time-varying pricing:

1. [T]he use of more dynamic pricing methods assumes that every customer has the ability to respond to hourly or daily price signals.

2. This ability is obviously easier for higher usage residential, commercial, or industrial customers who have greater flexibility for reduction or shifting the usage away from expensive peak hours and taking advantage of the option to lower bills and experience benefits…

[60] For more information on the Pacific Northwest GridWise™ Demonstration Project, see note 120, and accompanying text, below.

[61] Marcel Hawiger and Gayatri Schilberg, *Advanced Metering Infrastructure: What Happened to Demand Response?*, presentation to Joint Agency Workshop, September 30, 2004.

3. These options are not as easily available to customers with a fairly constant usage profile or who use such a low level of electricity that there is not a great deal of elasticity in their ability to reduce or shift usage, at least without suffering some potential discomfort or harm to health.

4. Such may be the case with many residential customers and is more likely the case with limited-income and payment-troubled residential customers who typically use less electricity than their higher-income neighbors.

5. The penetration of more energy intensive appliances is lower for limited-income customers….

6. On average, limited-income customers reside in housing units [that]…require less electricity to light, heat, or cool….

7. However, those [limited-income] customers with poorly insulated dwellings, in need of repairs, or who rely on less efficient and older appliances, are the least able to … take actions to reduce their energy usage due to their limited income.

8. Also, low-income renters may lack control over appliances provided by landlords….

9. These factors suggest that limited-income and payment-troubled customers are not as likely to be able to take actions in response to price signals that are available to higher-income customers….

10. The only practical option available to these customers is to do without or make changes in their lifestyle or family schedules to avoid using electricity at certain times of the day, even when that may adversely impact their health.

11. Finally, older consumers may need a constant level of heat or cooling to maintain a safe body temperature and "doing without" in the middle of a heat wave in order to avoid higher bills may result in dire health and safety consequences.[62]

Advocates who oppose AMI and real-time pricing also assert that there are less expensive ways to obtain demand response benefits and associated system cost reductions.[63] For example, TURN argued in California that the proposals to move forward with advanced metering and real-time pricing "ignored many tools already available to achieve demand response." Turn also

[62] See Barbara Alexander, *Smart Meters, Real Time Pricing, and Demand Response Programs: Implications for Low Income Electric Customers (Smart Meters),* Update, May 30, 2007. Available at: http://www.pulp.tc/Smart_Meters__Real_Time.pdf.

[63] Gerald Norlander, "Not So Smart? High Tech Metering May Harm Low Income Electricity Customers," (*Not So Smart)* Public Utility Law Project Blog, Monday, April 16, 2007. Available at: http://pulpnetwork.blogspot.com/2007/04/not-so-smart.html.

contended that air conditioner recycling programs[64] had provided some of the most reliable demand reductions in the nation.[65]

Critics have also argued that existing meter investment will be stranded, further burdening consumers. AMI opponents argue that customers should not be required to pay for the un-depreciated costs of existing metering and related hardware and software. Critics also contend that AMI metering and communications technologies are relatively new and untested, and that wholesale AMI investments should not be made—or at least not funded by ratepayers—given the immature state of the technologies and the market.[69]

2. Proponents of AMI as a tool to support time-varying pricing say AMI opponents are wrong on both facts and policies

Proponents of AMI as a tool to support time-varying prices say that opponents have the facts and the policy wrong. The key counterarguments of AMI proponents are listed below.[70]

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[64] An air conditioner cycling program is a form of direct load control. Customers who take service under the program agree to allow the utility to turn off their air conditioners, or raise the temperature setting, during times of system peak demands. They are called cycling programs because typically the utility will turn off only a quarter of the air conditioners subject to the program at a time, cycling through the entire pool in an hour but not requiring any one participant to go without air conditioning for a long time.

[65] As cited in the Interim Opinion in Phase 1 Adopting Pilot Program for Residential and Small Commercial Customer (Interim Opinion), in the docket captioned "Order Instituting Rulemaking on Policies and Practices For Advanced Metering, Demand Response and Dynamic Pricing," California PUC Rulemaking 02-06-001, June 6, 2002, available at http://docs.cpuc.ca.gov/published/final_decision/24435.htm#P60_717 (footnotes omitted).

[69] Alexander also argues that time-sensitive pricing in regions with wholesale energy markets sends distorted price signals to consumers, because energy markets do not function properly. This argument goes to issues of welfare economics theory, rather than practicalities of customer costs and benefits. Whether energy markets succeed in identifying marginal costs of usage at any given time, they do identify prices that suppliers will offer at any given time (aside from the impact of contracts that lock consumers into a given price in the short-run). While consumer demand response to such prices arguably does not optimize welfare under economic welfare theory, it will lower bills for customers who can lower usage in the face of the actual, but "distorted" market-based prices. If persistent, the demand responses of some residential customers could lower bills for customers generally, to the extent that wholesale price reductions achieved through the demand response of some customers can be shared with all customers (and that, taken together with operational savings, such reductions are larger than the incremental cost of the AMI investment).

[70] This list (drawn largely from the recent testimony of Stephen S. George in the pending Central Maine Power Company alternative regulation case, which rebuts the prefiled testimony of Barbara Alexander in that docket) summarizes many of the counterarguments brought out by Alexander and other AMI opponents. To the arguments in his testimony, we add other

1. There is a large and growing body of evidence indicating that residential customers can and will respond to time-varying prices and, in particular, dynamic price signals such as critical peak pricing and peak time rebates.
    a. On average, residential customers will reduce energy use on critical days by an amount ranging from 11 to 25 percent in response to prices or incentives that are between four and six times higher than the average price they would have paid under a standard tariff.
2. The resulting decrease in energy use during high-cost periods can generate substantial savings to customers and to society as a whole.
    a. Market price benefits of demand reductions can be substantial, even with quite modest reductions in peak demand.
    b. Not every customer must reduce load in order for demand reductions to produce benefits for all customers. Roughly 80 percent of the total demand reduction for customers on the CPP tariff in California was provided by only about 30 percent of customers. The majority of customers on the pilot tariff reduced load by less than the average value while others reduced load much more.
    c. The benefits derived from high responders, whether in the form of lower market clearing prices or avoided investment in generation, would accrue to all customers, not just those that reduce demand. That is, customers who volunteer for time-varying tariffs and reduce demand on high cost days provide positive economic benefits to all customers.
3. Opponents present no evidence in support of their claim that customers don't like and might be harmed by price volatility.
    a. Customers find dynamic rate options not only to be manageable, but preferable to more static TOU options.
    b. Studies also show that, once customers experience time-varying rates, many prefer them over standard tariffs.
    c. The claim that customers don't like and might be harmed by price volatility is largely irrelevant, as most time-varying prices are not volatile. They simply offer prices that vary over time.
4. Pilot results indicate that the reduction in peak period energy use is similar across a variety of dynamic rate options.
    a. Customers respond similarly to price increases (e.g., a CPP tariff) as they do to incentives paid for peak-period reductions (e.g., a peak time rebate program).
    b. Consumers are likely to respond to the carrot-only incentive of a Peak-Time Rebate in a manner similar to a Critical Peak Pricing rate.
    c. Many more customers are likely to take advantage of this no-risk PTR option than would volunteer for a CPP tariff because of the fear customers have about increased bills under a CPP rate.

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arguments made by George and other proponents of AMI in published materials and email correspondence via the EEI AMI listserv.

5. Low-income customers can and do respond to time-varying price signals, without risk to health and safety.
    a. Low-income customers participating in the California SPP pilot were less price responsive than higher-income participants, but on average (other than those on the low-income discount rate, who did not shift load in statistically significant amounts) they reduced their demands 11 percent.
    b. A substantial number of low-income households are high-use customers, and a substantial portion of high-income households are low-use customers.
    c. Across income levels, mean bill change values were statistically indistinguishable.
    d. Low-usage customers save proportionally more than do high-use customers.
    e. Low-income customers did not pay more under CPP tariffs.
    f. Lower-income households participating in the Chicago real-time pricing pilot were more likely than non-low-income customers to be high responders.
    g. There is no evidence that low-income and elderly customers may suffer dire health and safety consequences as a result of "doing without" in the middle of a heat wave in order to avoid higher bills.
    h. Even if such claims are true, they are not applicable to a peak time rebate program, where bills do not increase in the absence of a change in energy use, but could fall if a consumer adjusts his or her energy use.
    i. Even if a CPP tariff were implemented (on a voluntary basis), customers typically find that the kinds of changes that are sufficient to reduce demand during high priced periods can be achieved based on behavioral changes that, at worst, impose relatively minor inconveniences.
6. It is possible to adapt the results of the CA SPP to other service areas with different mixes of climate and end-uses.
7. Direct load control (DLC) programs are not superior to time-varying prices made possible by AMI.
    a. Customers on time-varying prices experience no greater discomfort from usage adjustments in response to high prices than customers whose load is adjusted by the utility under a DLC program.
    b. DLC is not suitable for all utilities, especially those with low penetration of central air conditioning.
    c. A focus on load control ignores the flexibility and range of behavioral adjustments that can result from a peak time rebate or critical peak pricing program.
    d. In response to a price signal, consumers can choose to adjust their thermostat, turn off a light, shift a load of wash from the peak to off-peak period, or make any number of other changes in order to reduce their energy bills. This flexibility is one of the primary values of a pricing option compared with the more "command-and-control" approach associated with load control.
    e. Air conditioner load control does not support retail customer choice, unlike AMI. Providing customer choice and customer control not only improves customer response, frequently by over 100 percent, it also substantially reduces program costs (uses performance rather than participation payments) and improves customer satisfaction.

f. Finally, price-based incentives create performance incentives, in contrast to the participation payments (unrelated to performance) in the vast majority of direct control programs. Changing from participation to performance incentives also eliminates all free riders. In other words, price is more effective and more equitable.

This report will not attempt to analyze all the competing claims made by AMI critics and proponents. Rather, we will focus on whether residential customers as a group, and subsets of residential customers, can and do respond to time-varying pricing. We will also look at the bill implications of using AMI as a tool to support the offer of time-varying rates.

To explore what is known about the response of residential customers, and particularly low-use, low-income customers, to time-sensitive pricing options made possible through AMI investments, we turn to a description of three recent dynamic pricing pilots. After describing the pilots, we will take up the key questions raised by the critics' arguments, to glean what information is possible from the pilot results concerning the suggested problems of AMI and time-sensitive pricing.

B. Description of three pilot demand-response pricing programs

To understand how the three pilots might help predict the effect of similar dynamic pricing initiatives in other states, we start with a description of the populations receiving the pilot prices, the nature of the pilot prices, the timing of the pilot, the circumstances of any peak or critical peak pricing, and other variables of note. These facts provide a foundation on which the reader can consider whether the circumstances of any given pilot make them applicable elsewhere. In Section G, we will describe the results obtained from these pilots, as well as some results from two other studies.

1. California Smart Pricing Pilot (SPP)

In response to the crisis in electricity pricing and availability in 2000-2001, California policy makers undertook a number of initiatives to head off repetitions of that experience. Among these was the California Statewide Pricing Pilot (CA SPP). The CA SPP experiment was designed to explore the effects of a variety of pricing options on customer load shapes and associated system costs.[71]

[71] Karen Herter, Patrick McAuliffe and Arthur Rosenfeld, "An exploratory analysis of California residential customer response to critical peak pricing of electricity," *Energy*, 32 (2007):25-34 (*Exploratory Analysis*), available at www.elsevier.com/locate/energy, at 26. The final report on the pilot, prepared by Charles River Associates, states that the pilot concluded in December 2004. Charles River Associates, *Impact Evaluation of the California Statewide Pricing Pilot (CRR CA SPP Final Report)*, March 16, 2005, at 4, available at: http://www.energy.ca.gov/demandresponse/documents/index.html#group3.

The California utilities tested the following three pricing options:

Figure XII: Pricing Options Tested in the CA SPP

1. A traditional TOU rate.
2. Two forms of Critical Peak Pricing:
    a. Participants assigned to the so-called Critical Peak – Fixed (CPP-F) tariff paid the critical peak price for a fixed number of hours on the days when the utility called a critical peak event, and a TOU rate otherwise. The utility notified such participants the day ahead of a critical peak event.
    b. Participants assigned to the so-called Critical Peak - Variable (CPP-V) tariff paid critical peak prices during a critical peak of varying lengths, between 2 and 5 hours, on the days when the utility called a critical peak event, and a TOU rate otherwise. The utility notified CPP-V customers the morning of a critical peak event.[72]

The pilot operators selected applicants for participation in the CPP-F group, to include a representative sample of customers statewide from within each stratum of usage and each of the four climate zones in California. They further selected subjects to ensure that the pool of participants fairly represented the dwelling types (apartment, single family) of customers in such usage and climate zones, and across the state.[73]

Program operators selected two groups of CPP-V customers. San Diego Gas & Electric (SDG&E) selected Track C participants from among customers participating in an ongoing smart thermostat[74] direct load-control program in the SDG&E service territory. Track A CPP-V participants were selected from SDG&E customers who were not on the direct load-control pilot, and who were high-use (>600 kWh/month) customers, residing in single-family homes with central air conditioning. Track A customers were offered a free programmable communicating thermostat (PCT).

The utilities selected control groups from among their customers. The control group members remained on the tariffs under which they had been taking service before the pilot. Utilities each selected the control group members to have roughly the same characteristics as the participants, in terms of stratum of usage, climate zone, and dwelling type.

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72 *Quantifying Demand Response,* at 54.

73 *Exploratory Analysis*, at 2.

74 A smart, or "programmable communicating thermostat" (PCT), is one that can be programmed by the customer or on the customer's behalf to adjust the temperature setting by time of day, day of the week, and in response to signals sent from the utility.

Each pilot rate was designed to be revenue-neutral. The TOU rate had an off-peak price lower than the average price for the standard rate, offsetting the price increase for on-peak periods. During the critical peak events, customers with a CPP form of rate saw much higher prices than during ordinary on-peak periods.

The underlying TOU peak price was 2 to 3 times the off-peak rate, depending on the utility. TOU peak prices were approximately 70 percent higher than the standard flat rate.[75] CPP-F and CPP-V prices on average across all utilities were about 10 cents/kWh in off-peak hours, 20 cents/kWh in peak periods, and 60 cents/kWh during critical peak hours.[76] The critical-peak price for CPP customers was between 5 and 10 times the off-peak price for the CPP rates, depending on the utility.[77]

Under the pilot the utility could call a critical peak event for up to 15 "critical" days of the year. The ordinary peak period for all residential tariffs ran from 2 pm to 7 pm on weekdays. The TOU peak periods were from 2 p.m. to 7 p.m.[78] The critical peak periods for participants on the CPP-F rate were also from 2 p.m. to 7 p.m., on critical event days. Thus, for CPP-F customers, the critical peak period during any given critical peak day was fixed at the 5 hours between 2 and 7 p.m. By contrast, the utility could define the critical peak period for the CPP-V customers between 2 hours and 5 hours, during the 2 p.m. to 7 p.m. period on critical peak event days.

The utilities notified CPP-F customers the day ahead of a critical peak event. They could notify CPP-V no later than the day of the critical peak event. The utility also signaled the PCTs of those customers with such devices at the beginning of the critical peak period. [79]

The utility could call up to 15 critical-peak events during the year (12 during the summer, and 3 during the winter).[80] Between July 1, 2003 and September 30, 2004, program managers called 27 critical peak periods.[81]

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[75] *Quantifying Customer Response*.

[76] *Exploratory Analysis*, at 27: "The average electricity price for the average non-participating California customer was about 13 cents/kWh."

[77] *Quantifying Customer Response*.

[78] Karen Herter, "Residential Implementation of critical-peak pricing of electricity," *Energy Policy* 35, at 2129.

[79] *Ibid.*

[80] *Exploratory Analysis*, at 27.

[81] *Ibid.*

2. Illinois: ComEd/Community Energy Cooperative - Energy-Smart Pricing Plan[SM]

The Community Energy Cooperative (Cooperative or CNT)[82] fielded its Energy-Smart Pricing Plan[SM] (ESPP)[83] in greater Chicago, Illinois from 2003 to 2006.[84] Under the pilot, Cooperative members could enroll in the pilot, and the Cooperative randomly assigned ESPP enrollees to one of two groups: participants (651 members), who took service under dynamic rates; and a control group (103 members), who did not receive any of the ESPP educational information, and continued to pay a flat rate for their electricity.

The area utility, Commonwealth Edison (ComEd) installed interval meters at the homes of participating Cooperative members. ComEd priced participants' electricity usage based on anticipated hourly changes in the market cost of the commodity. The Cooperative assisted in the administration of the tariff. CNT notified participants a day in advance of the prices that would likely apply the following day, so they could better adjust their usage.

CNT through 2004 also offered smart thermostats to participants, which allowed them to pre-program changes in electricity use (primarily air conditioning) based on price levels picked in advance. During 2004 and continuing into 2005, CNT installed cycling switches on the central air conditioners of 57 participants. These switches were set to cycle the air conditioner 50 percent of the time during a high-price period.

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[82] The Community Energy Cooperative Energy is a non-profit organization helping consumers and communities obtain the information and services they need to control energy costs. The Cooperative created CNT Energy in January 2000 as a division of its Center for Neighborhood Technology:

> CNT Energy works to help its more than 8,000 members obtain the information and services they need to control energy costs. The organization's members include individuals and small businesses in northern Illinois. Members receive up-to-date energy information in newsletters and on the Internet. They also have opportunities to participate in pilot programs designed to benefit consumers and promote energy efficiency. In addition, members become part of a collective voice advocating for energy policies that benefit everyone.

http://www.cntenergy.org/our_members.php.

[83] Unless otherwise noted, the information for this description of the Energy-Smart Pricing Plan[SM] is taken from the evaluations of the pilot conducted by Summit Blue Consulting, and available at: http://www.cntenergy.org/how-it-works.php.

[84] ComEd replace the in 2007 with a voluntary real-time pricing tariff available to all Commonwealth Edison customers. Ameren, another utility, also has offered a voluntary dynamic pricing tariff to its Illinois customers.

The Illinois Department of Commerce and Economic Opportunity (DCEO) provided the funding for the interval meters, programmable thermostats, and the evaluation reports on the pilot.[85]

3. Ontario Smart Price pilot

In 2006, the Ontario Energy Board (the Board) initiated the Ontario Energy Board Smart Price Pilot (OSPP) to test the reactions of and effects on residential consumer behavior of three different time-sensitive price structures:[86]

1. Time-of-use (TOU) prices
2. TOU prices with a critical peak price
3. TOU prices with a critical peak rebate (CPR)[87]

Hydro Ottawa ran the pilot between August 1, 2006, and February 28, 2007. Originally, the Board intended to end the pilot on December 31, 2006, but the Board decided to extend the pilot period until February 28, 2007, to obtain data on response during the coldest winter months. The Board initiated pilots by other Ontario utilities to test other tariff structures and specific demand response technologies.[88]

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[85] After 2004, the pilot stopped offering free smart thermostats, for lack of funding. According to Rob Lieberman, then head of CNT and now a member of the Illinois Commerce Commission, the Cooperative designed the pilot using low-tech methods of communication with customers, such as phone calls and emails from CNT, because CNT did not have sufficient funding to pay for the installation of more sophisticated communications equipment. E-mail to the author, December 17, 2007.

[86] Unless otherwise indicated, this description of the pilot and its results is taken from the July 2007 *Ontario Energy Board Smart Price Pilot Final Report (OSPP Evaluation)*, prepared by IBM and eMeter for the Board.

[87] Under a critical peak rebate tariff, the customer pays the underlying TOU rate for service, and faces no critical peak price during critical peak events, but rather may receive a credit for usage reductions during critical peak events, relative to a defined baseline. Hydro Ottawa defined a participant's CPR baseline usage as that customer's average usage during the same hours of the day over the participant's last five, non-event weekdays, as adjusted to increase the baseline. Hydro Ottawa increased the average usage by 25% to obtain the baseline usage. The rebate was calculated as the kWh difference between the participant's baseline usage and actual usage on the critical peak day, multiplied by C30¢.

In the Ontario pilot there was no reduction in off-peak pricing to keep the CPR rate revenue-neutral. *See OSPP Evaluation*, at Section 2.4, p. 18. The evaluation does not make it clear why the utility chose this design for the CPR tariff.

[88] Further information on these pilots is available on the OEB's website, at www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_regulatedpriceplan_smartpricepilot.htm.

Hydro Ottawa selected customers for three treatment groups out of those who responded to a solicitation mailed to customers with interval meters in place. Hydro Ottawa also selected a control group of non-participants from those residential customers who had expressed interest in participating.

Participants paid their usual (bi-monthly) bill at non-TOU rates as if they were not on the pilot price. In addition, they received monthly Electricity Usage Statements, showing the electricity supply charges that would apply on their respective pilot price plans. Upon enrollment, participants received a refrigerator magnet showing the TOU prices, periods, and seasons for the participant's price plan. They also received an electricity conservation brochure. Participants did not receive smart thermostats, although they could buy and install them on their own if they wished. The pilot did not include a direct load control component.

Neither participants nor the utility incurred incremental cost for the interval metering, since the utility had already installed meters in homes of customers eligible to participate, and was already recovering costs of the meter installations and related back office investments through adders to the customer charges applied to all customers.[89]

During the pilot, the utility billed all participants—TOU, CPP and CPR—for their usage at the TOU schedule in Hydro Ottawa's tariff. This TOU schedule had different prices for summer and winter, and for weekdays/non-holidays it had three pricing periods: off-peak, shoulder or mid-peak, and on-peak. TOU-only customers could save money if they backed off their usage during higher-priced periods, but there were no critical peak pricing periods for TOU-only customers.

Participants on the CPP rate were charged a separate, higher, rate for usage during the critical peak period. Customers on the CPR rate who used less than their baseline during critical peaks would pay the critical peak price (C30¢/kWh) during the critical peak period for usage, and receive a rebate equal to the CPP price times the difference between the "baseline" usage and their actual usage.[90] CPR customers earned a refund of C30¢ for every kilowatthour reduction below their baseline usage during the critical peak hours.

For critical peak price (CPP) participants, the Off-Peak price was reduced to C3.1¢/kWh, in order to offset the increase in the critical peak price and keep the overall effect of the rate

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[89] The government of Ontario had previously set a goal of universal installation of interval meters, and Hydro Ottawa was in process of fulfilling this mandate.

[90] Not all critical peak rebate tariffs follow this approach. For example, a utility could offer a customer the option to remain on the flat rate, and a Critical Peak Rebate for reductions relative to a baseline usage during Critical Peak periods. The differences in tariff design will create differences in the incentives to participate, and in the allocation of the benefits of the resulting demand response. The more that must be paid to the demand responder (in terms of rebates, in this case), the less of the resource savings will be available for sharing with other customers.

revenue neutral, relative to the pre-pilot usage. The CPP price was thus roughly 10 times as high as the off-peak price. The off-peak price for CPR customers was not reduced.

At the end of the pilot, participants received a final settlement statement comparing their electricity charges on the pilot prices with what their charges would have been on the standard rates under which most residential customers took service (and which the participants paid during the pilot). The dollar effects of the TOU, TOU-CPP, and TOU-CPR pricing plans (relative to the ordinary residential rates) flowed through to participants through a settlement payment. The final settlement document compared their charges under the pilot tariff to what they would have been under the standard prices. The "thank-you" payment was the sum of $75 plus their pilot savings (or minus their pilot losses) relative to the standard tariff.

The utility declared critical peak days for CPR and CPP customers based on pre-determined temperature and Humidex[91] thresholds. Hydro Ottawa notified CPR and CPP participants of an upcoming critical peak day one day before the event, by telephone, email or text messages. The participants then had the choice of "buying through" the critical peak period[92] or else cutting back their usage during the critical peak period. According to the program design, critical peaks would last for only 3 or 4 hours on any give critical peak day. The maximum number of critical peak days allowed for the pilot was nine.[93]

Hydro Ottawa applied all price changes only to the commodity portion of a customer's electricity bill. Delivery, debt retirement,[94] and other charges were not changed in the pilot. None of the treatment or control participants took their commodity service from a non-utility provider.[95]

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[91] According to the Canadian Centre for Occupational Health and Safety, "Humidex is used as a measure of perceived heat that results from the combined effect of excessive humidity and high temperature." http://www.ccohs.ca/oshanswers/phys_agents/humidex.html

[92] "Buying through" is a term used in some voluntary demand response programs (i.e. without direct load control by the utility) for continuing to use, and pay for, energy at the rate the customer would have used in the absence of the higher peak (or in this case, critical peak) prices.

[93] During the pilot months, during which the weather turned out to be relatively moderate, only 7 critical peak events were declared: 2 in August 2006, 2 in September 2006, and 3 in January 2007.

[94] Canadian tariffs sometimes have line items to amortize specific debts.

[95] As in the U.S. jurisdictions with retail choice, the great majority of residential customers take their commodity service from their distribution utility, in this case Hydro Ottawa. These customers would likely be on a Standard Offer, Standard Service, Default, Basic Service or equivalent service for non-shopping customers in a retail competition jurisdiction in the United States.

C. Results of three demand-response pricing pilots

1. To what extent did residential customers on average reduce load in response to critical peak pricing and direct load control in the pilots?

All three pilots showed at least load shifts by residential customers on average[96] in response to critical peak price signals.[97] Average responses were typically more pronounced during weather extremes, particularly during hot weather, and among customers with relatively high-demand end uses, such as central air conditioning. Automatic responses, made possible by direct load control, programmable thermostats or other devices, contributed to significantly higher demand responses.

Some participants, however, in at least two of the pilots, increased their usage on average during some critical peak periods. Further, mean load reductions observed in any given period do not show that all customers in the pricing group did or were able to reduce load during the period in question. In at least one pilot group, the group average reductions were almost entirely the result of huge load reductions by a small number of participants. Evaluators of another pilot noted that not all participants reduced their loads, although the pilot group under study did reduce loads on average.

As with all discussions of demand response to pilot tariffs, we must remember that bill impacts, the factor of most concern to most customers (and many legislators), do not move in lock-step with demand responses. Bill impacts will be discussed in a separate section, below.

2. Summary of average residential demand responses

The following summary[98] shows overall average residential elasticity and impact results from the various pilots discussed above:

[96] This section will not discuss groups broken down by income or usage level, at least not directly. The findings with respect to such groups are discussed in a separate section, below.

[97] Response to ordinary TOU rates was less pronounced than response to critical peak pricing. We will focus our discussion on more higher pricing of narrowly focused critical peaks.

[98] Data extracted from Table 2, Keisling, *Prospects and Challenges*, p. 36; ESPP and Ontario load reduction data from Section III.B, above.

Figure XIII: Summary of Recent Pilot Demand Reduction Results

Pilot	Pricing Type	Year	Own-Price Elasticity	DLC or PCT?	Peak Consumption Reduction[99]
Ameren-UE	CPP	2005		n/a	9.3%-17.8% (ave. 13%)
Ameren-UE	CPP	2005		All	14.4%-30% (ave. 23.5%)
CA SPP	CPP-F	2003	-0.035	some	n/a
CA SPP	CPP-F	2004		some	13% (average)
CA SPP	CPP-V	2003-4	-0.027 to -0.044	all	27% (average)
CNT ESPP	CPP-F, CPR	2003	-0.42	no	As much as 23%
CNT ESPP	"	2004	-0.08	some	
CNT ESPP	"	2005	-0.47	some	
CNT ESPP	"	2005	-0.69	all	
CNT ESPP		2003-5			As much as 15%-20%
Ontario	CPP	2006		some	25.4% (summer CP hrs)
Ontario	CPP	2006-7			No response, or increase
Ontario	CPR	2006			17.5% (summer CP hrs)
Gulf Power	CPP	2001			22% (high price signal)
Gulf Power	CPP	2001		all	Max. 41% (CP event)
GridWise™	RTP	2006-7			15-17% (average)

The results of several pilots, then, show that residential customers, *on average,* have responded strongly to various types of dynamic pricing. Critical peak pricing, in particular, has shown promise as a demand response tool for residential customers.[100] The addition of programmable communicating thermostats significantly increases the responses observed.

a. California

A number of analysts have reviewed the data from the CA SPP. Their evaluations suggest that on average, most types of customers will reduce their critical peak loads in response to critical peak pricing. Technology such as smart thermostats boosted this response noticeably.

[99] The chart gives averages for the participant groups, unless otherwise noted.

[100] This report does not focus on time-of-use rates, as such rates did not call forth the strongest responses in any of the pilots.

In evaluating the California pilot, Herter *et al.* compared the participants' loads over all critical peak hours to their average loads on non-critical weekday peaks."[101] Herter *et al.* found statistically significant load reduction for participants on average, both with and without automated end-use control technologies.[102]

On average, according to Herter *et al.*, during 5-hour critical peak periods, participants without control technology (so-called "manual" participants) used 4 percent to 13 percent less energy than they did during normal day peak periods, depending on the temperature during the day. Herter *et al* estimated that "manual" participants reduced load across all the critical peak hours by 0.23 kW on average, relative to their average loads across all non-critical weekday peak periods.[103] During critical peak days with mild temperatures, the researchers observed average load reductions for the manual group of 4 percent compared to normal day loads.[104] As a percent of normal (non-critical peak) day loads, their response was greatest on the hot days—on average, "manual" participants' critical peak load on hot days was 13 percent lower than their non-CPP day load.[105]

Not all customers (or groups of customers) will reduce their loads in response to higher peak prices. Indeed, customers may actually increase peak loads in any given peak period, despite the higher unit price they will pay for such usage. In California, for example, in one mild-temperature period, the manual group actually *increased* load by 8 percent on average during a critical peak period. Finally, for manual group participants on cold days, load fell on average 9 percent below the corresponding load on normal days.[106]

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[101] *Ibid.*, at 29. "Since participants are on TOU rates on normal days, the demand response estimates are the incremental impacts of CPP events beyond the impacts of the TOU pricing."

[102] Herter *et al* divided critical peak pricing participants into two main groups for the purpose of impact analysis: (a) a "PCT" group, whose members had installed programmable communicating thermostats connected to their central air conditioning units and other high-load end uses—the CPP-V customers; and (b) a "manual" group, whose members did not have such response technologies—the CPP-F customers.

[103] *Ibid.*

[104] *Ibid.* This effect was considered load shifting, given an increase in energy use over the entire day.

[105] *Ibid.* The researchers opine, based on comparisons of energy usage, that the CPP vs. normal load differential represents conservation at critical peak hours, rather than simply load shifting.

[106] *Ibid.* Average consumption (total energy use) on these cold days increased 1 percent, due to increased loads in the morning hours before the critical event.

Figure XIV: CA SPP - Average Response of Customers without Programmable Communicating Thermostats, by Temperature Band

Source: Herter, *et al*, Tables 2, 3[107]		
Temperature Band	**% Load Change**	
50 – 54.9	-11	-9
55 – 59.9	-7	
60 – 64.9	***8***	-4
65 – 69.9	-7	
70 - 74.9	-2	
75 – 79.9	-6	
80 – 84.9	-6	
85 – 89.9	-7	
90 – 94.9	-4	
95 – 99.9	-15	-13
100 – 104.9	-12	

Note that when Herter *et al* consolidated the eleven original temperature bands into three, both manual and CPP-V groups showed load reductions in response to critical peak events in all three temperature bands. The 8 percent increase shown in the cool temperature band of 60 to 65 degrees is folded into the reductions in the other temperature bands between 60 to 95 degrees.

Smart thermostats, a technological assist to customers seeking to adjust usage in response to price, boosted demand responses considerably. Those participants with these programmable communicating thermostats (the "PCT" group) used 25 percent less on average over the hottest 5-hour critical peak periods than they did on normal day (TOU) peak periods. Participants with central A/C and programmable thermostats, on the CPP-V rate, achieved an average reduction of 41 percent during one of the 2-hour critical peaks:

[107] Negative number indicates demand reduction in critical peak hours; positive number indicates demand increase in critical peak hours. This convention is maintained for consistency with the presentation of results for the other pilots. Note that the OSPP evaluation reversed the signs.

Figure XV: CA SPP - Percent Demand Response, Participants with PCTs, by Temperature Band and Length of Critical Peak

Source: Herter *et al*, Table 4		
Temperature Band	**PCT – 5 hours**	**PCT – 2 hours**
70 - 74.9	-8	-14
75 – 79.9	-1	-13
80 – 84.9	-6	-16
85 – 89.9	-7	-17
90 – 94.9	-25	-41

Thus, during the CA SPP study period, the average residential customer load responses during critical peak pricing periods ranged from a drop of 1 percent to a drop of 41 percent, depending on the temperature band at the time of the critical peak event.

The highest responses occurred on the hottest days, whether or not the participants had to reduce load manually or could use smart thermostats programmed in advance to respond to price signals by lowering loads in the house. On these high-temperature days, the manual group (less than 50 percent air conditioner penetration) on average reduced load 13 percent, and the group with programmable communicating thermostats (100 percent air conditioning penetration) reduced load on average 25 percent. Among those with air conditioning, on average they reduced load by 17.4 percent, compared to the 25 percent drop achieved by those with PCTs (see CA SPP Final Report, Table 4-19).

The Herter *et al* results are largely consistent with the effects estimated by Charles River Associates, broken out by climate zones rather than by the temperature band of the critical peak days:

Figure XVI: Percent Changes in Demand, Peak Period of CPP Days, by Climate Zone, TOU, and CPP-F Groups

Climate Zone / Tariff	**Cool Zone**	**Mild Zone**	**Hot Zone**	**Very Hot Zone**	**Statewide**
CPP - F	-11%	-11%	-16%	-16%	-12%

Source: *Impact Study*, Figure 3.

As can be seen from the following table, customers on the CPP-F pilot rate reduced their peak period usage considerably more during critical peak events than during normal peak periods, in each climate zone.

Figure XVII: CA SPP - Percent Change in Peak Period Energy Use by Climate Zone, CPP-F Participants

Source: CRA CA SPP Final Report, Executive Summary		
Climate Zone	Normal Peaks	Critical Peaks
Zone 1	-2.2%	-7.6%
Zone 2	-3.3%	-10.1%
Zone 3	-5.6%	-14.3%
Zone 4	-6.5%	-15.8%
Statewide	-4.8%	-13.1%

CRA reported that participants on the CPP-V tariff in Track C (subject to critical peaks of varying lengths, with "day-of" notice of critical peak events, and already participants in the SDG&E demand-response program) showed strong responses (an average reduction of 27.23 percent) to utility calls of critical peak events. Participants on the CPP-V tariff in Track A (SDG&E single-family households with central air conditioning, offered smart thermostats, not previously on the demand-response program) responded less intensely, reducing demand during critical peak events on average by a little over 15 percent.

Based on data reported by the California Energy Commission, CPP-F participants reduced load during critical peak days on average. The CPP-F customer load reduction was most pronounced during hot and very hot weather peaks. On average during cool-weather critical peaks, CPP-F customers slightly increased their usage.[108]

b. Illinois: ESPP

Summit Blue Consulting prepared an impact evaluation of the Illinois ESPP for each of the pilot's three years. The analysts presented most results in terms of price elasticity: the percentage by which participants changed their usage in response to a percent increase in price during the critical peak period. This approach makes it difficult to compare results to those of other pilots, where the data is primarily presented in terms of reduction of peak consumption, without connecting that peak reduction to the price increase. However, there are some data available about percentage load reductions in the ESPP evaluations, and there are data available regarding price elasticities estimated for participants in the other pilots discussed here.

Over the course of the pilot, Critical Peak/Real Time pricing participants on average reduced their peak usage between 15 percent and 20 percent.[109] Participants with switches on their central air conditioning units allowing programmed cycling off during high-price periods

[108] Pat McAuliffe and Arthur Rosenfeld. *Response of Residential Customers to Critical Peak Pricing and Time-of-Use Rates During the Summer of 2003* (CEC Residential Report), California Energy Commission, September 23, 2004, Figure 4.

[109] Posting by Steven George to EEI's AMI Listserv, citing a recent presentation by Anthony Starr, in response to author's questions, December 5, 2007.

showed stronger demand responses on average than other participants. For example, on the hottest days of the summer of 2004, at the highest peaks of the day, those with air conditioning cycling switches reduced loads on average about 23 percent, whereas participants as a whole reduced load by 15 percent.[110]

The evaluators estimated the key results from the impact evaluation of the 2003 ESPP program using data from August, the month in which the system tends to peak in ComEd's service area. That peak month in 2003 was substantially cooler than normal; as a result, peak-period prices were lower than in previous years.[111] From the 2003 data, the evaluators drew the following conclusions:

1. Over half of all participants showed noticeable responses to price notifications.
2. Most of the rest of the participants showed some response.
3. Some of the participants showed no response.
4. On average, participants did respond to hourly prices. Residential customers responded to hourly prices (over and above the "high price" notification) with an average price elasticity of -4.2 percent.[112]
5. Participants responded strongly to advance notification of high prices (prices over 10 cents/kWh); consumption decreased in some cases by more than 25 percent in the first hour. This response tapered off both (1) over the length of the high price period, and (2) as the number of successive days of notifications increase.[113]

According to the then-head of the Cooperative running the pilot, results of the pilot in 2003 demonstrated significant participant response to high price notifications, up to as much as 23 percent of peak demand,[114] when compared to usage on a similar day without high prices.

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[110] Bob Lieberman, member of the Illinois Commerce Commission, presentation: *Demand-side Resources in a Restructured State: Possibility or Non-Sequitur*, Presentation to Annual MARC Conference, June 18, 2007. Available at: http://www.puc.state.mn.us/news_events/events/marc_07/speakers/lieberman.pdf.

[111] The evaluators suggested that these results might not be representative of responses during peak months whose weather and associated usage requirements are more representative of normal peak months.

[112] For every 1 percent increase in the price of electricity for a given hour, participants reduced load by 4.2 percent on average.

[113] The Hydro Ottawa pilot evaluators referred to this effect as "decay" of the demand response.

[114] Lieberman, *Demand-Side Resources in a Restructured State*.

In the second summer, the Chicago area weather was milder than in the first summer of the ESPP pilot.[115] Accordingly, in 2004 there were only 19 hours, spread over seven days, when prices were over $0.10/kWh (so-called "high-price" days). Peak-period prices were correspondingly lower than during previous years. Electricity use for air conditioning was also lower than normal. The evaluators reported the following results, among others:

1. In 2004, participants did not respond strongly to notification of high prices (prices over $0.10 per kWh).
2. Residential customers in 2004 had an average overall price elasticity of -8.0 percent (compared to a -4.2 percent response in 2003).

Summit Blue noted that the summer of 2004 was unusually cool, and so "not particularly taxing of participants' good will and energy saving efforts." For this reason, these results were "not surprising." Summit Blue opined that the results were due to the limited use of air conditioning during non-high priced periods (the baseline usage was small), and to sparing use of air conditioners during the few high temperature days (which were also high price days).

In 2004 it was not possible to confirm the effect of high price notifications. The lack of comparison days in summer 2004, and the relatively low use of air conditioning on even the hottest days of that summer, precluded a similar analysis for the second year of the pilot.

Cooperative-controlled direct load control devices, added to some participants' air conditioners in 2004, did not produce statistically different results for such participants in that summer. Summit Blue attributed this outcome to the relatively low amount of air conditioning used on even the hottest summer days of 2004.

The weather in the Chicago area was dramatically hotter in the third year of the pilot.[116] In the summer of 2005, the ComEd system experienced record peak electricity demands. In addition, the prices for natural gas (an input to the production of electricity) that summer exceeded prior summer's levels, contributing to higher electricity prices. These market conditions resulted in high hourly electricity prices throughout the summer.

Summit Blue reported the following notable effects from the 2005 evaluation (among others):

1. ESPP participants continued to respond to hourly electricity prices in a manner similar to prior years, with an overall price elasticity of -4.7 percent.

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[115] It was the fourth coolest summer in the previous twenty-five years. Summit Blue acknowledged that these weather patterns did not provide the ideal environment for testing a typical range of peak prices and usage patterns.

[116] June and July of 2005 were the sixth warmest of all comparable months on record since 1871.

2. Participants in 2005 showed a substantial response to the high-price notifications (i.e., when prices exceed $0.10/kWh).
3. Automatic cycling of the central-air conditioners (turning the compressor on and off for short periods of time via remote control) during high-price periods added as much as 2.2 percent to a participant's price elasticity, for a total price elasticity of 6.9 percent during such periods.
4. Customers' responses to high-price notifications declined somewhat as the number of consecutive notification days during the summer increased and as the length of a given high-price period increased (snapback effect). Summit Blue also identified what it calls a "recharge" effect, as customers' response recovered to initial levels the longer the number of days between high-price notifications.

c. Ontario Smart Price Pilot

OSPP outcomes were measured by comparing the electricity consumption behavior of customers receiving the experimental prices (TOU, CPP, and CPR, respectively) to the consumption behavior of the control group: customers remaining on their existing two-tier non-TOU rates. For all three price groups combined, participants responded with statistically significant[117] shift in load away from peak periods during on-peak periods on the 2 critical peak days called in August 2006. No statistically significant shift was detected during the critical peak days declared in September. In January 2007, CPP participants actually increased their load on one critical peak day, and displayed no statistically significant change in load on the other two critical peak days:

Figure XVIII: Ontario SPP Results: CPP Pricing

Summer			
Critical Peak Day	**Load Reduction**	**Actual Max Temp (Celsius)**	**Humidex**
Friday, August 18	-27.7%	30	35
Tuesday, August 29	-10.1%	25.2	28
Thursday, September 7	n/s[118]	22.4	n/a
Friday, September 8	n/s	26.5	31

Winter		
Critical Peak Day	**Load Reduction**	**Actual Min. Temp. (Celsius)**
Tuesday, January 16	n/s	-18.7

[117] At the 90 percent confidence level. The evaluators note that many of the load shift results are statistically significant at the 95 percent and even 99 percent confidence level.

[118] The term "n/s" denotes that the results were not statistically significant.

Wednesday, January 17	**7.2%**	-16.1
Friday, January 26	n/s	-21.3

The load reduced during critical peak hours across all four summertime critical peak days was 17.55 for CPR participants and 25.4 percent in the case of CPP participants[119]. CPP participant demand reduction across the entire summertime peak period (11am to 5pm) during the same critical peak days was not as great as it was across the specified critical peak hours. During this narrower set of hours, CPP participants reduced demand in amounts ranging from 2.4 percent to 11.9 percent.

Analysts examined load shifting away from the on-peak period for all days in the pilot, not just critical peak days. Evaluators found no statistically significant load shifting from on-peak periods as a result of the TOU price structure alone.

d. Other program results

Summary results available for two other dynamic-pricing pilots are consistent with the results of the three pilots examined in detail here.[120]

In 2001, Gulf Power, a Florida subsidiary of Southern Company, commissioned an evaluation of its residential demand response program, Good Cents Select. This program is based on a combination of metering and control technology, customer service, and a four-part TOU pricing structure. Good Cents Select customers all have a programmable thermostat that allows them to establish settings based on temperature and price. Each Good Cents Select home has a programmable gateway/interface that enables the customer to program up to four devices in the home to respond to price signals. Gulf Power has installed meter-reading technology and load control technology that enables customers to program load shifts in response to price

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[119] Time of use participants showed lower responses than either CPP or CPR customers.

[120] The material on Gulf Power and the Olympic Peninsula evaluations is drawn from the discussion by Kiesling, *Prospects and Challenges*, pp. 26-27, which in turn references Severin Borenstein, Michael Jaske and Arthur Rosenfeld, *Dynamic Pricing, Advanced Metering and Demand Response*, University of California, Center for the Study of Energy Markets, Paper No. CSEMWP 105 (2002).
http://repositories.cdlib.org/cgi/viewcontent.cgi?article=1005&context=ucei/csem and Government Accountability Office, *Electricity Markets: Consumers Could Benefit From Demand Programs, But Challenges Remain*, GAO-04-844, August 2004, available at *http://www.gao.gov/new.items/d04844.pdf*. Recently, the Pacific Northwest National Laboratory issued its reports on the Pacific Northwest GridWise™ Demonstration Project (which included the Olympic Peninsula Project and the Grid Friendly™ Appliance Project). These reports, and an overview, are available at:
http://gridwise.pnl.gov/docs/op_project_final_report_pnnl17167.pdf,
http://gridwise.pnl.gov/docs/gfa_project_final_report_pnnl17079.pdf, and
http://gridwise.pnl.gov/docs/pnnl_gridwiseoverview.pdf.

signals. Customers also pay a monthly participation fee of $4.53 (said to cover approximately 60 percent of program costs to the utility).

In 2001, Gulf Power customers on average reduced energy usage 22 percent during high-price periods and 41 percent during critical periods. The Gulf Power evaluator reported that customer satisfaction is 96 percent, despite the monthly participation fee.[121]

The Olympic Peninsula GridWise® Testbed Project was a demonstration project run by the Pacific Northwest National Laboratory (PNNL) and local utilities, funded by a grant from the United States Department of Energy, with additional contributions from appliance and load control equipment manufacturers. PNNL tested a residential network with highly distributed intelligence and market-based dynamic pricing. The pilot lasted from April 2006 through March 2007. PNNL and the utilities enrolled 130 households who heated with electricity. Each household received a PCT with a visual user interface that allowed the consumer to program the thermostat in response to price signals, if desired. Households also received water heaters equipped with a GridFriendly™ appliance controller chip that enables the water heater to receive price signals and to be programmed to respond automatically to those price signals. Consumers could control the sensitivity of the water heater through the PCT settings.

Participants continued to purchase energy from their local utility at a fixed, discounted price. In addition, they received a cash account with a pre-determined balance, which the utility replenished quarterly. The participants' energy use decisions would determine their overall bill. The billed amount was deducted from their cash account; participants kept any residual as profit. The worst a household could do was a zero balance. Participants could log in to a secure web site to see their current balance and how effective their energy use strategies were.

The participating households received extensive information and education about the technologies available to them and energy use strategies made possible by these technologies. They were asked to choose a retail pricing contract from three options: (a) a fixed price contract (with an embedded price risk premium), (b) a TOU contract with a variable CPP component that could be called by the utility in periods of tight capacity, or (c) a RTP contract that would reflect a wholesale market-clearing price in 5-minute intervals.[122] The project managers controlled the thermostats of the RTP households.[123]

The price offered for demand reductions varied according to the constraints on the feeder serving the peninsula. The project limited the feeder capacity to test the usefulness of demand response and distributed generation options for relieving feeder constraints. During times of

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[121] Borenstein, et. al. (2002), Appendix B.

[122] The real time price was determined using a "uniform price double auction," in which buyers (households and commercial) submitted bids and sellers submitted offers simultaneously.

[123] All households could override project control of their loads. Pacific Northwest GridWise™ Testbed Demonstration Projects, Part I: Olympic Peninsula Project, Final Report (PNNL Final Report), October 2007, p.vii.

severe constraint, the effect on the cost of utility resources available to the peninsula drove up the price offered for demand response.

The households ranked the contracts offered, and the utility then placed them into three fairly even groups of participants receiving one of the pilot rate types, and one control group.[124] All households received either their first or second choice of pilot type.

A preliminary analysis of data from the first nine months of the program showed that peak consumption on average for the RTP group decreased by 15 to 17 percent, even though overall energy consumption increased by approximately 4 percent.[125] In the Final Report, PNNL estimated that RTP customer load was reduced by 5 percent during the baseline level of feeder constraint (and associated real time prices), and by 20 percent during periods of severe feeder constraint, and associated market prices.[126]

In 2005, Ameren-UE, a Missouri utility fielded a pilot testing a three-tier TOU rate, as well as the TOU rate with a CPP feature and the same rate with CPP and smart thermostats. The pilot was targeted at high summer usage residential customers. The CPP group without thermostats reduced load between 9.3 percent and 17.8 percent over the critical peak event days, with a reduction of 13 percent averaged over all eight critical peak days. Those with CPP pricing plus a smart thermostat showed a range of reductions between 14.4 percent and 30 percent, depending on the critical peak day, and averaged a 23.5 percent reduction over all eight critical peak days.[127]

3. To what extent were the participants in the three pilots representative of residential customers, including particular subsets of such customers?

Anyone considering econometric or sociological data must be conscious of whether the participants in the experiment (here, the pilots) were representative of the population at large. If the subjects of the pilot were not representative of the population as a whole, then the results of the pilot are potentially “biased.”

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[124] The members of the control group received the enabling technologies and had their energy use monitored, but they did not participate in the dynamic pricing market experiment.

[125] Keisling notes that the price elasticity results for the RTP group are highly specification-dependent: the sign, magnitude, and statistical significance of the elasticity estimate varies greatly depending on arithmetic model specified to estimate the relationship between independent variables and the dependent variable (here, percent change in usage). Regulators need to be on the lookout for this phenomenon, which is not unique to the Olympic Peninsula pilot.

[126] PNNL Final Report, at x.

[127] Rick Voytas, “Ameren UE Critical Peak Pricing Pilot,” presentation June 26, 2006.

There are a number of ways in which a sample can become biased.[128] A common issue for social science experiments is the so-called "self-selection" bias. That is, did the participants select themselves into the pilot, and were people with particular usages, incomes, housing types, attitudes, or other demand-influencing factors more likely to sign up to participate than other types of customers? Was the result a sample of households that does not represent the population whose behavior we are trying to predict?

To the extent the question is whether customers will "self-select" into a voluntary time-varying tariff option, the pilot designers did as well as might be expected in the circumstances to minimize experimental self-selection bias. Self-selection bias was a concern for all the pilot designers and evaluators. Absent the mandatory placement of a customer on a particular rate, any pilot will have to rely on decisions by customers to sign up for the pilot.[129] Pilot designers had to address the potential for self-selection by participants who were not representative of the target population of the tariffs being studied.

Unable to select participants at random from target populations, pilot managers in California and Ontario still took steps in an effort to obtain groups of participants that matched some of the key characteristics of interest in the greater population to which they belonged. In Ottawa, despite utility efforts to obtain a representative sample, evaluators determined that participants were more likely than non-participants to: (a) reside in detached single-family homes, (b) live in newer housing, (c) have central air conditioning, (d) have more education, and (e) have a higher income, than the population as a whole.[130]

In the California SPP, pilot administrators took pains to ensure that participants were representative of California electricity customers by climate zone, housing type, and low or high usage.[131] Evaluators also collected data on treatment group participants' pre-pilot usage, which they say allowed them to separate out the effects of factors other than the pilot rates (including self-selection bias) on their demand responses.[132] Herter *et al.* note, however, that they lacked

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[128] This statistics term is not meant to imply an intentional skewing of the data, but rather an objective description of a tendency in the data to bias the results.

[129] According to the CRA evaluation, California SPP pilot designers did seek a ruling from the California Commission placing customers in the various treatment groups, with the right to opt out, but the Commission declined to force customers into any of the pilot rates. CRA *SPP Final Report*, at 21. The Commission noted that California law required that participation in time-of-use pricing pilots be voluntary. California Public Utilities Code Section 393(c)(3), cited in the *Advanced Metering Final Decision*, Section IV(B) (Legislative Mandates), available at: http://docs.cpuc.ca.gov/published/final_decision/24435.htm#P60_717.

[130] *OSPP Evaluation*, Section 3.4. The Ontario pilot evaluators did not discuss self-selection bias in their report.

[131] Exploratory Analysis, at 27.

[132] CRA, *CA SPP Final Report*, at 5, and *CEC Impact Study* at 3-4. CEC used a "difference of differences" technique. From the CRA description, they used a similar technique.

the data to perform the statistical operations commonly used to reduce the possibility of self-selection bias in the results.[133]

Evaluators in some cases used statistical techniques to assess the pilot data, in an effort to overcome the possible impact of self-selection bias.[134] However, the characteristics they chose as predictors of participation, and thus used to correct for self-selection, did not include all the factors that one might reasonably surmise could distinguish a customer interested in and willing to participate from one who is not.

For example, the participation factors used in the ESPP analysis included (a) whether the household had recently acquired new appliances, (b) whether they used a fan to reduce costs, (c) the number of people in the household, (d) whether they lived in a single-family detached house, and (e) whether a respondent was 65 years of age or older.[135] These factors did not include such characteristics as ability to read and write,[136] a desire to help address social problems, or environmental consequences of energy use, an interest in having one's opinion taken into

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While this technique controls for difference in pre-treatment energy use, it does not necessarily eliminate all effects of self-selection into participation. McAuliffe and Rosenfeld note, for example, that this approach had limited usefulness given the small sample sizes and the large confidence intervals in the pre-treatment period. *CEC Impact Study,* at 14.

[133] *Exploratory Analysis,* at 32-33. Herter *et al* reference the seminal paper by later Nobel Prize winner James Heckman, "Sample Selection Bias as a Specification Error," *Econometrica*, Vol. 47, pp. 153-161 (1979). Tests following Heckman's method are commonly known as "Heckman" procedures. Heckman's insight has spawned a large literature on various ways to use participation factors and other statistical tools to try to correct for self-selection bias. The difficulties in the application of these methods can be appreciated by reference to the following articles, among many: Raymond S. Hartman, "A Monte Carlo Analysis of Alternate Estimators in Models Involving Selectivity," *Journal of Business & Economic Statistics*, Vol. 9, No. 1. (Jan. 1991): 41-49, available at http://links.jstor.org/sici?sici=0735-0015%28199101%299%3A1%3C41%3AAMCAOA%3E2.0.CO%3B2-G; and François Bourguignon, Martin Fournier, Marc Gurgand, *Selection Bias Corrections Based on the Multinomial Logit Model: Monte-Carlo Comparisons*, September 6, 2004.

[134] See, e.g., *ESPP 2003 Evaluation*, Section 2.1. The Mills Ratio described there is a step in the Heckman form of correction for self-selection bias. See, e.g., Dennis J. Aigner and Khalifa Ghali, "Self-Selection in the Residential Time-of-Use Pricing Experiments," *Journal of Applied Econometrics,* Vol. 4, Supplement: *Special Issue on Topics in Applied Econometrics*, December 1989, pp. S131-S144. Available on line at:http://links.jstor.org/sici?sici=0883-7252%28198912%294%3CS131%3ASITRET%3E2.0.CO%3B2-S.

[135] *Exploratory Analysis*, at 33.

[136] In California and in Ontario, the utility solicited participants by mail.

account, or a facility with filling out forms, handling new technologies, or mathematics, just to name a few.[137]

Each of the pilots suffered from the fact that participation was voluntary; that is, selected participants either had to come forward in response to a solicitation of interest in being part of an experiment. While at least in the case of the CA SPP a "wet signature" was a legal requirement imposed on the pilot program designers, the fact remains that as a result, customers identified for the pilot had to self-select into participation. Circumstances of the enrollment processes for the various pilots that differ from the circumstances of an ongoing tariff, yet may have affected decision of certain groups of otherwise-eligible customers not to apply (or conversely provided some customers an unrealistic incentive to apply for the pilot), include:

Figure XIX: Some Potential Sources of Self-Selection Bias in Pilots

- Cash incentives for participation (California and Ontario).[138]
- Requirement to join a cooperative membership organization with other aims and activities besides energy efficiency and demand response.
- Requirement that applicants be able to read and understand letters of solicitation sent by their utility (California and Ontario).
- Need to be reachable by the utility within the time frame of the pilot.[139]
- Interest in helping solve the state's energy problems (California).

Customers who would not have chosen such rates without cash incentives did not apply in the California and Ontario pilots (although, on the other hand, customers who would have chosen the pilot even without cash incentives did apply). If there are no such cash rewards when piloted rates are offered on a permanent (and voluntary, opt-in) basis, customers may not opt to take service under the rate.

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[137] Prospective participants in the SDG&E service area were told they would "have an important role in influencing how electricity is priced for millions of California customers in the future" and that they would be "contributing to a statewide research effort to help create a more secure energy future for California." At least at the beginning, prospective participants in the Chicago ESPP had to join the CNT cooperative; not all members of the population could or would go through such a step to achieve energy savings.

[138] A sizable number (20 percent or more) in all California treatment groups indicated that they joined primarily because of the promised $175 payment. Momentum Market Intelligence, *SPP End of Summer Survey Report (Draft)*, January 21, 2004, p. 61. On an open-ended version of the question of why a participant entered the pilot, 15 percent to 33 percent of the respondents, depending on tariff type, included the $175 payment as a reason. *Ibid.*, at 60.

[139] Almost two-thirds of those solicited for participation in California were either unreachable after two attempts, or were otherwise excluded from participation. There is no information on the breakout of those who were unreachable, and the reasons for the inability of the utility to achieve contact with them.

There is no practical way to eliminate self-selection bias where a pilot is set up to test whether customers will voluntarily sign up for a particular tariff. In such a case, the regulator may be served by having expert statistical, econometric, or sociological advice when considering evidence such as the pilot evaluations discussed here.

If the regulator is testing mandatory or opt-out tariffs, self-selection does not present the same concerns, so long as the regulator (or legislature) permits the pilot designers to place customers on the pilot tariff without their consent. There are sound policy reasons to do so.

4. Did low-use or low-income customers respond to dynamic pricing?

Because low-income customers are at disproportionate risk of non-payment and disconnection,[140] analysts have paid special attention to the likely ability of such customers to take advantage of dynamic pricing. The chief argument regarding adverse impacts on low-income customers follows from the fact that such customers are disproportionately low-use customers. Thus, to the extent that low-use customers cannot lower their usage during critical peak periods, the argument goes, they will necessarily experience higher bills than if AMI and dynamic pricing were not in place. In addition, AMI opponents argue that low-income customers lack the funds to make their homes more efficient, as by buying appliances that draw less power.

Others argue that low-use customers enjoy better load shapes than other residential customers, and so will benefit from the reductions in off-peak pricing while not being exposed to substantial critical peak bills. One analyst in California, looking at the data for that state, observed that low-use customers indeed reduced demand by a smaller nominal amount of kW, but that as a percentage of their pre-existing load, their reductions were substantial.[141] As a result, according to this analyst, low-use customers enjoyed a higher percentage bill savings from the institution of time-varying pricing than higher use customers. As a corollary, to the extent that low usage is a marker for low-income, low-income customers would also enjoy such bill reductions.

As discussed below, however, the data on low-use responses to critical peaks, and low-income customer responses, do not paint a clear picture of reduced demand during peak periods.

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[140] Ron Grosse, former manager of customer accounts for Wisconsin Public Service, estimated that approximately one-half of residential customers who did not pay their bills could not afford to pay them. Low-income customers represented considerably less than one-half of the residential customer base, however. See generally "Win-Win Alternatives for Credit and Collection," available at: www.citizensutilityalliance.org/energy/Win-Win.pdf.

[141] *Residential Implementation*, at 2122.

a. The responses of low-usage participants varied, even within the same pilot

The three pilots examined in this report provide varied evidence of the demand response of small usage customers to dynamic pricing. Depending on the definitions of low-use and low-income, different analysts reported different results even within the same pilot. [142]

With regard to the situation of low-use customers, TURN in California conducted an in-depth analysis of usage patterns among residential consumers in the State,[143] in support of its argument that AMI and dynamic pricing do not make sense for low-use residential customers. The *Review of CA Load Research* confirmed many anecdotal impressions of usage differentials among customers. Overall, the report provided evidence of the following:

Figure XX: California Data on Small Customer Usage

1. Customers who use under 130 percent of the California baseline[144] on average use proportionally less peak energy than customers using larger amounts.

2. Small customers have a much lower saturation of air conditioners.[145]

[142] The Ontario pilot evaluation did not produce a breakout of demand response by participant usage or household characteristic. According to the evaluators, 85 percent of all participants (and controls) had central air conditioning, and 82 percent lived in single-family homes, *OSPP Evaluation,* at 26. It may be asked whether the strong summer critical peak result found in this pilot was the result of air conditioning response, and would not have been as strong had the participant groups not been dominated by single-family homes with central air conditioning. However, the Report does not permit a conclusion on this point.

[143] William B. Marcus, Greg Ruszovan, JBS Associates, *"Know Your Customers": A Review of Load Research Data and Economic, Demographic, and Appliance Saturation Characteristics of California Utility Residential Customers ("Review of CA Load Research"),* filing by TURN with California PUC, in App. 06-03-005, Dynamic Pricing Phase, December 11, 2007.

[144] In response to the crisis in electricity prices and reliability in 2000-2001, the California legislature passed what has become known as AB1X (Assembly Bill No. 1 from the First Extraordinary Session (Ch. 4, First Extraordinary Session 2001)). Among other things, AB1X included price protections for residential consumers using 50 percent to 60 percent of the average residential consumption, depending on climate zone. This level is known as the "baseline," not to be confused with the "baseline" usage estimated in the Ottawa Hydro pilot against which critical peak rebates were calculated by that utility.

[145] The report noted that as many as 64 percent of those using under 130 percent of baseline in the SDG&E territory do not have an air conditioner.

3. Small customers have fewer discretionary appliances. For example, over 20 percent of them do not have in-home laundry facilities.

4. Small customers' use, therefore, is more closely tied to non-peak appliances—refrigerators, lights, and electronic equipment—than that of customers who have higher usage.

5. Small customers also have considerably lower incomes than larger customers on average. On the SDG&E and Edison systems, over 50 percent of low-use customers have incomes under $40,000 per year. By contrast, the largest customers (over 1500 kWh per summer month) on average have household incomes over $100,000.

These findings are not surprising. They confirm common sense impressions of the electricity usage and socioeconomic characteristics of different households. It is not enough, however, to identify factual conditions that give rise to questions about the ability of certain users to benefit from AMI or dynamic pricing. In particular, if certain customer groups were indifferent to AMI and dynamic pricing, but other customers benefited, it would not make sense to deny such other customers the benefits of AMI.

Further, if certain customers are at risk from AMI costs and dynamic pricing impacts, but the system as a whole (and other customers) benefit greatly, the regulatory task then becomes determining if it is fair for vulnerable customers to remain at risk, and, if not, to require that utilities develop and employ tools to protect them.[146]

Finally, at least where standard non-time-varying rates are not sharply tiered, low-use customers should receive benefit from tying the price of electricity closer to the differing resource cost at different times. The very fact that they tend not to have or use the high-draw appliances (e.g. central air conditioning) means that they use proportionately less during critical peak hours than other customers. They will get the benefit of lower off-peak prices under CPP, and will not be harmed by high critical peak prices, which apply only in a very few hours.

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[146] Some would even argue that regulators have no responsibility to prevent harm to a group of customers whose rates increase because the regulator requires pricing that more closely follows cost causation, or provides some other system benefit in which such customers do not share. To the extent AMI is such a case, they would argue, it should be left for legislators to develop a system of transfer payments that move some of the net savings from AMI to those who are harmed. "One cannot make effective public policy by rejecting a program producing net benefits because it harms one group. That principle would terminate highway construction on the grounds that some people will die from accidents." Scott Hempling, Director, NRRI, personal communication with the author, December 20, 2007. Others, including this author, believe that effective modern ratemaking requires consideration of questions of affordability, even in the absence of explicit legislative mandates (as exist in some states).

The results of the California Statewide Pricing Pilot send mixed signals as to the likely response of low-use customers on average to demand-response tariffs. As analyzed by Herter, the pilot in California showed that on average, low-use customers (600 kWh/month or less) did not reduce load in response to critical peak pricing.[147] Further, Herter found no statistically significant difference in this result between low-use customers of different income levels.[148]

Charles River Associates, on the other had, found that low-use participants (50 percent or less than average daily use) in the CA SPP *did* respond on average to critical peak pricing, albeit not to the extent of high-use customers (200 percent or greater than average daily use).[149] Looking at specific housing characteristics and associated high-demand end-uses, CRA found similar patterns. According to CRA, those in single-family homes and those with central air conditioning responded more strongly to critical peak pricing than those in multifamily units and those without central air conditioning.[150] Those in multifamily housing and those without central air conditioning[151] nonetheless responded strongly to critical peak pricing.

The chart below displays these CRA 2003 and 2004 results:[152]

Figure XXI: CA SPP: CPP-F Percent Reduction in Peak Usage, by Usage Level and End-Use

CPP-F Customers by Usage/ End-uses	Year 1	Year 2
High Use	-17.2%	-14.7%
Low Use	-9.8%	-12.2%
Single-family house	-13.5%	-14.0%
Multi-family building	-9.8%	-11.8%
Central A/C	-12.8%	-17.4%

147 *Residential Implementation*, at 2126 and Figure 4.

148 *Ibid.*, at 2126.

149 CA SPP, *Summer 2003 Impact Analysis*, CRA, August 9, 2004, Table 5-9, p. 90; *Final Report*, Table 4.19.

150 *Ibid*.

151 Customers with pool pumps made large percentage reductions in their peak usage, but the results were not statistically significant, so they are not reproduced here.

152 CA SPP, *Summer 2003 Impact Analysis*, CRA, August 9, 2004, Table 5-9, p. 90; *Final Report*, Table 4.19.

No Central A/C	-12.3%	-8.1%
Average all customers	*-12.5%*	*-13.1%*

In Illinois, the relative average demand response of lower-usage and higher-usage customers was quite different from the California experience. For example, in 2003, ESPP participants in multi-family units had the highest response of all to high-price notifications. In 2004, those living in multi-family units with no air conditioner had the strongest overall demand response.[153] Those in single-family homes, with central air conditioning, had the weakest response: [154]

Figure XXII: ESPP 2004 Elasticities and % Load Reduction, by Hhld Type and A/C

Household Type	Air Conditioning	Elasticity	CPP % Load Reduction
Single Family	none	-.08	
Single Family	window only	-.08	
Single Family	central	-.052[155]	
Multifamily	none	-.117	-16% to -19% overall
Multifamily	window only	-.105	
Multifamily	central	-.087	-30% overall

These Illinois results contradict the argument that lower-usage customers cannot and will not reduce load. This conclusion is muddied somewhat by the fact that in this same year (2004), customers in multi-family units showed no statistically significant response at all to high-price notifications, in sharp contrast to their strong response to such notifications in 2003. In 2005, further, the price elasticities of ESPP participants in multi-family homes and single-family homes were similar.[156]

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[153] 2004 ESPP Evaluation, Section 2.2.

[154] *Ibid.*, at 10; posting by Steven George to EEI's AMI Listserv, citing a recent presentation by Anthony Starr, in response to author's questions, December 5, 2007.

[155] First hour of CPP event only.

[156] *2005 ESPP Evaluation*, at 13. Again, the question facing policy makers is not merely whether certain groups of customers cannot respond to price signals, but rather (assuming the policy maker is concerned with the bill impacts on such customers), whether the incremental AMI costs assigned to such customers outweigh the operational benefits shared with them plus whatever share they may enjoy of resource savings made possible by those who can and do reduce load.

b. Low-income customers did exhibit demand responses on average, but there was great variation around the mean

Analysts evaluating the California SPP and the Chicago area ESPP looked at demand response by the income of the household.

ESPP did not gather information on customer income directly, but rather used zip codes to identify participant neighborhoods by relative income levels. In 2005, ESPP evaluators found no difference in demand response between customers in low-income and non-low-income neighborhoods.[157] The same evaluation, however, showed a greater demand response among customers who received their high-price notification by email on their home computer.[158]

In her paper on implications for residential customers of the California pilot, Herter shows the following 2004 summer responses, by income and household usage:

Figure XXIII: CA SPP - Mean HHd KW Change, 12 CPP Events, Summer 2004, by Household Income and Usage

Household Income	Percent CPP Event Load Reduction	
	Low-Use Customers	High-Use Customers
$0 - $24,999	-1.0%	-5.7%
$25K - $49,999	-5.6%	-40.0%
$50K +	-0.9%	-18.5%
All incomes	-2.4%	-20.8%

According to this data, 2004 CA SPP participants with incomes below $25,000 showed the weakest demand response, even those with high usage. By contrast, high-use households in the $25,000 up to $50,000 annual income group showed by far the largest response to critical peak events. As in the ESPP case, however, even low-use low-income CA SPP participants showed some demand response in Herter's analysis.[159] Also, high-usage customers in the high-income group analyzed by Herter showed moderately strong demand responses, contrary to the

[157] *Ibid.*, at 15.

[158] *Ibid.* While computer ownership is becoming more democratic, low-income households remain disproportionately unlikely to have computers, and hence email capability.

[159] The opponents still may have an argument that AMI investments will raise bills for low-income customers higher than the cost savings they enable through demand response (even after offsetting the incremental AMI costs by the operational savings all customers will share). As will be discussed in the next section, the ability to shift load and lower bills need not be positively correlated.

assertion that high-income customers would not respond to price signals, but would "buy through" and keep their loads at previous levels.[160]

Charles River Associates performed a different analysis of CA SPP responses broken out by household income in its reports to the California PUC and Energy Commission. CRA identified only two broad income groups: those with household incomes at or below $40,000, and those with incomes at or above $100,000.[161] In 2003 and 2004, CRA found that both groups showed demand response to critical peak events, although in both cases the higher-income customers showed the higher demand response. Using the broader income categories, the CRA analysis showed a smaller difference than the Herter analysis between the responses of those at the lower income levels and those at the highest income levels:[162]

Figure XXIV: CA SPP - Demand Reductions, by Broad Income Groups, 2003-04

Higher-Income ($100K+)	-15.1%	-16.2%
Lower-Income ($40k-)	-12.1%	-10.9%

The Brattle Group also analyzed the demand response of participants by income in the CA SPP.[163] Brattle Group provided results for two categories of low-income CA SPP customers: customers by income level (self-reported), and customers on the low-income discount rate (CARE).[164] The analysts found that high-income households were somewhat more price-responsive than low-income households. They state, however, that "the difference is not substantial and low income customers showed demand response."

Statewide, according to the Brattle Group analysis, low-income CA SPP participants on average reduced their load during critical peak hours by 11 percent, whereas high-income customers reduced their load on average by 16 percent during critical peak hours. Participants statewide who did not receive the CARE discount were much more price responsive (reducing their load by about 16 percent) than those who did receive the CARE discount (reducing their

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[160] Note that high-income, low-use consumers did not respond strongly to critical peak pricing.

[161] CRA also had a category for pool ownership, which probably corresponds positively with income.

[162] CA SPP Final Report, Figure 4-19.

[163] Ahmad Faruqui and Lisa Wood, "The Impact of Dynamic Pricing on Low Income Customers: A Discussion Paper," in *Impact on Low Income,* The Brattle Group, 2007.

[164] CARE is a reduced price tariff for low-income customers. Availability is restricted to low-income customers. CARE customers receive a 20 percent discount on the electric bill versus non-CARE customers. About 20 percent of residential customers in California are on the CARE rate. *Impact on Low Income,* 6.

load by only 3 percent). These results compare to price responsiveness of about 13 percent across all climate zones for all participants.[165]

The CA SPP also included a small pilot, called Track B, to examine whether low-income customers in urban neighborhoods living in close proximity to a fossil-fuel-burning power plant had different load responses if they received support in their efforts from community groups. The Brattle Group analyzed the results of the Track B pilot to develop some insights into the demand response behavior of these participants, based on income. As summarized by the analysts, on average this group of low-income customers did display at least a small amount of demand response:

> Over two summers – 2003 and 2004 – the average daily shift in usage during a critical peak day was about 1.2 percent for low-income customers in Track B in response to an information only treatment and about 2.6 percent in response to a price signal and information. To place these numbers in perspective, the average customer in the same climate zone displayed a response of 7.6 percent.[166]

The Brattle Group analysts noted, however, that four of the Track B participants cut their usage in half in response to CPP calls, and one of these reduced household demand by two-thirds during the winter period. The large reductions of this handful of participants, when averaged over the small number of participants in this pilot Track, likely skewed the average result downwards, and may even mask load increases among others in the group. These data, accordingly, do not assure regulators that all low-income customers have an opportunity to reduce their usage sufficiently in response to price signals to warrant the cost of supplying those signals.

c. Limitations on use of pilot evaluations of low-income response

One difficulty regulators face in using all these data to understand the likely CPP demand responses of low-income customers in California (or elsewhere) is the inadequacy of the evaluators' income definitions. The definitions do not correspond to any of the standard definitions of poverty. There are at least three issues that regulators would want to explore before applying these CA SPP income-response results to their own states.

First, poverty properly understood will vary by household size. It takes a higher income to feed, clothe, and house a larger number of individuals. Second, cost of living varies widely; an income that would be sufficient in one area (even within California, for example), might not be in another. Third, the lower income measures used in the above analyses are too broad to permit a realistic understanding of the ability of low-income households to respond to CPP. None of the analyses of the response to the CA SPP pilot, with the possible exception of the review of CARE customer responses, satisfactorily addressed these three issues.

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[165] *Ibid.*

[166] Ahmad Faruqui, Lisa Wood, *Impact on Low Income*, 1.

As to the definition of poverty by household size, the single most useful starting point for analysis is the so-called Federal Poverty Level (or FPL). The United States Department of Health and Human Services annually publishes the so-called Federal Poverty Guidelines. These guidelines provide a basis for allocation of anti-poverty funding, and for determining eligibility for federally-funded means-tested programs.[167]

As to the household size issue, the federal poverty guidelines handle this concern by stating a different poverty threshold depending on the numbers of persons in the household. As to the definition of poverty, it is customary in means testing to use a multiple (typically 150 percent) of the FPL, as the dividing line between low-income and non-low-income households.[168]

The FPL is adjusted annually in February. Below are the 2007 Federal Poverty Guidelines, including a calculation of the more commonly used 150 percent of FPL. Comparing this chart to the income levels used by Herter and CRA, and assuming an average household size of between 2 and 3 persons, it is possible to see that even the narrower band used by Herter includes too many households with incomes above 150 percent of the FPL. A household fitting the CRA income cut-off of "below $40,000" would have to be quite large (6 people) in order to fit the most commonly-used definition of poverty (150 percent of the FPL). [169]

The $25,000 cut-off used by Herter is a more reasonable approach than the CRA income categories; a family need only have this income and be composed of three persons to fit the definition of low-income.[170] Even so, a more granular analysis of the relationship between income and demand response would be necessary to have confidence that the results shown in California represent the likely behavior of low-income participants, even from California.

[167] The guidelines do not vary from state to state, except that Alaska and Hawaii have higher limits, in recognition of their generally higher costs of living.

[168] Those responsible for low-income programming have long understood that 100 percent of the FPL is too low an income to sustain a minimally safe and adequate standard of living. Regulatory commissions that make use of the FPL to determine eligibility for low-income rates and programs typically use the 150 percent cut-off, or a higher level.

[169] In California, a family of four with an income at below $40,000 would qualify for the CARE low-income rate discount. Thus, CARE's income limit is approximately twice the FPL.

[170] Average household size in the United States is approximately 2.61 persons per household, according to the Census Bureau. See: http://factfinder.census.gov/servlet/ACSSAFFFacts?_event=&geo_id=01000US&_geoContext=01000US&_street=&_county=&_cityTown=&_state=&_zip=&_lang=en&_sse=on&ActiveGeoDiv=&_useEV=&pctxt=fph&pgsl=010&_submenuId=factsheet_1&ds_name=DEC_2000_SAFF&_ci_nbr=null&qr_name=null&reg=&_keyword=&_industry=

Figure XXV: 2007 U.S. Poverty Guidelines

Persons in Household	**48 Contiguous States/ D.C.**	***150 % of FPL***	**Alaska**	**Hawaii**
1	$10,210	*$15,315.00*	$12,770	$11,750
2	13,690	*20,535*	17,120	15,750
3	***17,170***	***25,755***	21,470	19,750
4	20,650	*30,975*	25,820	23,750
5	24,130	*36,195*	30,170	27,750
6	27,610	*41,415*	34,520	31,750
7	31,090	*46,635*	38,870	35,750
8	34,570	*51,855*	43,220	39,750
For each additional person, add	3,480	*This column derived.*	4,350	4,000

SOURCE: *Federal Register,* Vol. 72, No. 15, January 24, 2007, pp. 3147–3148

The pilots provide some curious data with respect to the concern sometimes voiced that low-income customers tend disproportionately to be heads of household who remain in the home during the day, and thus are necessarily on-peak electricity users. The ESPP evaluation noted that a greater demand response was observed among households where a larger number of persons were at home during the critical peak period.[171] By contrast, Ontario pilot customers with small children who stayed in the home reported to evaluators that they found it difficult to shift such electricity-using activities as laundry off the critical peaks.[172] Understanding better the reason for such apparent differences in the experiences of stay-at-home customers with families in the two pilots would shed valuable light on a commonly-heard worry about time-of-use pricing.

d. Customer disability creates vulnerability as well.

Finally, on the impacts of demand response pricing on vulnerable customers, AMI opponents raise the specter of elders fearing to turn on their air conditioning in a heat wave. The inability of socially- or mentally-disabled customers to recognize dangerous conditions and take steps to ward off the risks may be a larger concern than the financial situation and age of the customer. None of the pilots, however, was designed to shed light on the question of how dynamic pricing will affect those who, for reasons of mental or social disability, are not in a position to respond to price signals, or even disconnect notices.

[171] 2005 ESPP Evaluation, 15.

[172] OSPP Final Report, 52.

Anecdotal evidence from three heat waves in recent history in which large numbers of customers perished suggests that fear of the cost of air conditioning was not the main reason for the failure of most victims to use it at the time of the heat wave. Nor were the victims predominantly elderly.[173] Rather, many who suffered heat stroke and died in recent heat waves were in their 40s and 50s. A number of these individuals lived in make-shift housing without air conditioning, some had no air conditioner to turn on, and some who avoided using air conditioning for reasons of frugality did not, apparently, do so because they were unable to pay for it.[174] The underlying reasons, based on newspaper accounts and some scholarly studies, were not so much poverty as social or mental disability.

For example, many who perished in recent heat waves were men living alone without the support of a social network, and some had mental health problems. One elderly woman who died from heat stroke resisted turning on her air conditioner, according to her children, because she had grown up in post-war Germany under conditions of terrible privation, and would not allow herself what she considered a luxury, although she could afford air conditioning. Similarly, the recent death of an elderly Michigan woman in the winter as the result of lack of heat due to an electric utility disconnection did not result from an inability to pay. Rather, both the customer and the daughter living with her (who survived) suffered from mental impairments. Neither was capable of paying the bill, although the customer had funds on hand.

Thus, bill affordability among elders may not be a key concern with time-varying pricing. At the same time, regulators and utilities should be concerned about the impact of dynamic pricing on vulnerable customers. Precisely because of the potentially diminished ability of mentally or socially disabled customers to take rational steps in response to challenging circumstances, the regulator and the utility cannot protect such customers by implementing demand-responsive tariffs on an opt-out basis. Only an opt-in rule will prevent such customers from potentially being left on a rate that they cannot manage effectively.

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[173] The author recalls reading press reports following the Chicago heat wave of 1995 to the effect that some elders perished because they could not afford air conditioning but feared opening their windows because they lived in high-crime neighborhoods. I was unable to obtain confirmation of these reports for this paper.

[174] See, e.g., Jennifer Steinhauer, "California Heat Wave Ends With a Death Toll Near 25," *The New York Times,* September 7, 2007, available at http://www.nytimes.com/2007/09/07/us/07heat.html; Hank Shaw, "Victims of S.J.'s fatal heat wave had so many things in common," August 20, 2006, *The Record OnLine,* available at http://www.recordnet.com/apps/pbcs.dll/article?AID=/20060820/NEWS01/608200331/-1/a_special07 ; KR Kaiser, CH Rubin, AK Henderson, MI Wolfe, S Kieszak, CL Parrott, and M, Adcock, *Heat-related death and mental illness during the 1999 Cincinnati heat wave*, Am J Forensic Med Pathol. 2001 Sep;22(3):303-7; JC Semenza, CH Rubin, KH Faltern, JD Selanikio, WD Flanders, HL Howe and JL Wilhelm, *Heat-related deaths during the July 1995 heat wave in Chicago,* Am J Prev Med. 1999 May;16(4):269-77; Eur J Public Health. 2006 Dec; 16(6):583-91.

5. How persistent, year over year, are the voluntary load shifts or reductions resulting from price signals, with or without smart meters?

With the exception of the Illinois ESPP, which operated for three successive years, none of the recent real-time pricing pilots operated for more than one or two summers. In the California SPP pilot, time of use prices began July 1, 2003; the pilot was over by end of summer 2005.[175] The Ontario pilot was even shorter: August 1, 2006 to February 28, 2007. The lack of a track record of persistent demand responses over a number of years casts doubt on the reliability of the findings from these pilots.

Although it lasted three years, the Illinois ESPP did not provide a full opportunity to study consumer reaction to numerous permutations of weather and price. The pilot did not begin until August 2003. And, as Summit Blue candidly stated in its evaluations of the ESPP pilot, the two first summers unusually low temperatures meant that firm conclusions about residential customers' response to RTP would have to await experience during a more normal (i.e., hot) summer.[176]

The third summer of the ESPP was much warmer than normal; record high gas prices were driving up electricity prices.[177] Certainly, the 2005 ESPP pilot was a better test than the 2003 and 2004 pilots of residential responses to typical critical peak prices, because participants in the hot summer of 2005 faced the unpleasant choice between persistent sweltering heat and expensive peak electricity. Even the 2005 data cannot answer the ultimate question of whether observed effects will persist over time.[178] In particular, it would be valuable to see how residential customers respond to real time pricing (and even to direct load control) if they are subjected to high peak prices summer after summer, and face the need to pay higher bills or cut back on air conditioning and other end use comforts every hot summer.

The recent experience of Puget Sound Energy (PSE) with time of use pricing suggests that public acceptance may still be a difficult hurdle for pricing initiatives, at least those that do not produce bill savings for those on the rate. After a pilot phase, PSE put all 300,000 of its residential customers on its Personal Energy Management (PEM) program in 2000, on an opt-out basis, in response to the crisis in the Western markets. For almost a year, PSE's program received positive response from customers. Under the program, customers were charged an on-

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[175] There are some data on responses of customers on CA SPP rates after the end of the pilot, but no there is published report on such data of which this author is aware.

[176] Customers who participated in ESPP in 2003 showed no decline in response in 2004.

[177] 2005 ESPP Evaluation, at ES-1.

[178] In addition, the costs of AMI will have to be recovered from consumers regardless of whether the weather (and related peak demands) is warm enough (or cold enough, as the case may be) to drive the system towards the levels of peak demand, and associated resource costs, that were assumed in developing a cost-benefit justification for the AMI investment.

peak summer rate 6.25 cents per kWh and an off-peak rate of 4.7 cents, plus a $1 incremental monthly charge to be on the rate.

Few customers chose to opt out of the PSE program at first, and participants reported high levels of satisfaction. However, once they began receiving comparison bills in late 2002, opt-outs increased rapidly.[179] After a public outcry in protest against the rates, customers rapidly abandoned the program. As Kiesling explains, the issue for customers was that, "for most of them, even though they had shifted their use of electricity, their bills had either not gone down, or had actually gone up compared to what they would have paid under the old rate."[180]

The Puget Sound Energy experience is consistent with the reports by customers in the three pilots reviewed here that reducing their bills was a key driver in their participation in the demand response programs. To the extent this short-term bill impact focus remains a dominant source of demand response, the success of any program will be vulnerable to the bill impact experience of participants. AMI and associated demand-response pricing options may fare better in those areas of the country where the alternative would be increasingly sharp cost increases for generation, at marginal prices well above the Puget Sound 6.25 cent on-peak rate.

Concern about persistence of results also stems from the observation that much of the pilots' demand response can be attributed to a minority of participants. All three pilot evaluations noted that the average reductions were made up of large decreases from some participants, with more modest reductions by some participants, and no reductions from many on the tariff (if not also increased usage from some). The more "average responses" are driven by extraordinary reductions by a small number of customers, the more reason there is to question whether such customers can achieve the pilot levels of load reduction year after year, at least at pilot levels.

Looking at the self-reported changes made by CA SPP participants as they responded to price signals,[181] there is further reason to wonder if lifestyle changes made in a pilot setting will persist once the novelty wears off. Customers in California reported little in the way of self-perpetuating demand response. Fewer than 10 percent of participants stated that they turned their air conditioner thermostat up; and only a little over 10 percent stated that they turned off their air conditioning or used it less to reduce peak usage. For all pilot pricing groups, the largest single change reported in usage was shifting clothes laundering to off peak hours (between 30 percent and a little over 40 percent of participants mentioned this technique for peak load reduction). Without minimizing the contribution of a number of small-impact changes

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[179] Kiesling, *Prospects and Challenges*, at 33.

[180] *Ibid.* It might also be that the easing of the Western market difficulties (and low hydropower water problems) by late 2002 reduced the sense of public crisis that led consumers to accept new ideas for addressing electricity costs in Washington State.

[181] Momentum Market Intelligence, *SPP End of Summer Survey Report (Draft*), January 21, 2004, p. 31.

customers reported making (such as turning off lights and using appliances less during peaks), it is safe to ask whether the high-yield responses will persist year after year.[182]

Utilities that promoted residential real time pricing in the 1980s saw that participation in voluntary time-sensitive tariffs eroded over time. Ralph Abbott, now President of Plexus Research, Inc.,[183] has worked on utility time-of-use programs for residential customers since the mid-1970s. In 2005, he sounded a cautionary note about TOU pricing for residential customers, stemming from his experience with the promotion of TOU rates during that earlier period.[184] He cited research performed for the Electric Power Research Institute (EPRI) to the effect that acceptance of TOU by residential customers was extremely limited.

For example, the cited EPRI survey from 1985 found that most utilities offering voluntary residential TOU rates had participation rates of less than 1 percent. A 1991 EPRI report produced similar results. While about 78 percent of the utilities surveyed offered some type of voluntary residential time-of-use price, only 1.4 percent of the residential customers of reporting utilities were served on such rates in 1990.[185]

Abbott states that many major utilities had more customers on TOU rates in 1984 or 1991 than they did in 2004. He cites the experience of a large Northeast utility that had more than 26,500 residential customers voluntarily taking service under TOU rates in the mid-1980s, but by 2004, only 11 customers remained on these rates.[186]

Abbott argues that there are a number of reasons for this erosion of participation:

1. Optional TOU rates were not well-promoted.
2. Peak periods were so long that a majority of the customers' usage would occur on peak, and be subject to the higher prices.

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[182] McDonough and Kraus argue that energy efficiency initiatives, such as the replacement of incandescent bulbs with compact fluorescents, produce load reductions that are more persistent over time than those achieved through time-varying pricing. Catherine McDonough and Robert Kraus, "Does Dynamic Pricing Make Sense for Mass Market Customers," *Electricity Journal*, Vol. 20, Issue 7 (August/September 2007).

[183] *Deciding on "Smart" Meters: The Technology Implications of Section 1252 of the Energy Policy Act of 2005,* prepared for the Edison Electric Institute, September 2006.

[184] Ralph E. Abbott, "Time-of-Use Rates: Sideburns and Bellbottoms?" *Energy Markets*, July/August 2005, pp. 6-8.

[185] *Ibid.* The EPRI study also calculated that each such customer used, on average, 1374 kWh per month, a very high amount for residential customers, and (if the mean and median were close) probably indicative of the use of central air conditioning and/or electric space heat.

[186] *Ibid.*, p. 8.

3. The ratio of peak to off-peak prices made the rate a “no-win” for consumers – the cost to the consumer (in dollars, convenience, lost opportunities or otherwise) of shifting load off-peak was not compensated by avoiding sufficiently high peak prices.
4. The charge for incremental metering costs ate up the savings potential.

Abbott concludes with his impression that consumers who chose the TOU rate simply wore out and lost interest after a few years.[187] Based on these observations, Abbott questioned whether time-sensitive pricing for residential customers is no more than a fad that is bound to fade over time, as the earlier implementation of such rates did. In this article, Abbott did not address the potential impacts of (1) reduced metering costs, (2) offsetting operational savings, (3) improved capability to target demand-response pricing to critical peaks, and thereby (4) reduce the extent of inconvenience to customers taking service under such pricing and (5) increase the differential between off-peak and peak pricing. These factors, as he has noted,[188] would tend to improve the chances that today’s demand-response pricing options will achieve acceptance among consumers, and lead to persistent demand responses.

There are additional reasons to have reason to believe that customer response to dynamic pricing will be stronger today, and last longer, than was the case with TOU pricing from the 1980s and earlier.[189] The increases in residential peak usage today are driven by increased penetration and use of air conditioning, which can now be cycled off conveniently using fairly inexpensive control technology, without, it appears, producing great discomfort. In this author’s opinion, the most hopeful development is the narrowing of the period of very high prices to a relatively few hours in the year, thus minimizing discomfort, as well as the penalty of paying such prices if the customer cannot or will not reduce load.

Critical peak pricing, made possible by technological advances in metering and communications systems (albeit not requiring AMI), allows the utility to limit the number of high-priced hours during which customers would face price signals intended to stimulate load shifting. Critical peak pricing simultaneously heightens the differential between this focused critical peak price and non-CPP prices (thus making avoiding the critical peak more beneficial to the customer). Also, among the public there is a renewed concern about rising energy costs and looming environmental consequences of energy use that has prompted many regulators to explore new options for load reduction. A variety of factors make it likely that, despite occasional dips in resource costs, the trend in system costs will continue up, and electricity costs will not drop sharply as they did in the 1990s. For this reason, the economic benefits of demand response will likely continue at a high enough level to justify price time-of-use price differentials sufficient to incent at least some demand response.

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[187] *Ibid.*

[188] Email to the author, January 30, 2008.

[189] Roger Levy notes that TOU rates offered by utilities in Arizona have attracted “upwards of 30 percent customer participation.” Email to the author, January 30, 2008.

6. If taking service under time-varying tariffs is voluntary, what portion of residential customers is likely to choose such pricing?

In order to estimate the demand response savings likely to flow from implementation of AMI and time-varying pricing facilitated by AMI, it is necessary to estimate the numbers of customers likely to take service under such rates.[190] There are essentially three ways in which time-varying pricing can be presented to customers.[191] First, all customers of a given class can be placed on such rates on a mandatory basis. Second, customers can be placed on the rate, but given the opportunity (perhaps with certain conditions such as a minimum time on the rate) to opt out of being on the rate. Finally, customers can be given the choice to opt in to the rate.

If the time-varying tariffs are mandatory, the calculation of the portion of customers in a given class taking the rate is simple: 100 percent. What remains is the estimation of the average response of the entire group of customers. The estimation of the portion of customers that will take the rate over time is more complicated where the customer has a choice about whether to go on the rate.

Leading analysts estimating the resource value of AMI-facilitated time-varying pricing argue that over time, 80 percent of customers placed on opt-out time-varying tariffs will remain on the rates, and 20 percent of customers who must affirmatively opt to take service on such rates will do so.[192] The authors give no evidence that supports such estimates. As discussed above in Section III, no pilot has operated for long enough to provide a basis for projecting long-term participation rates. Time-of-Use rate experience from the 1980s and 1990s cannot provide encouragement to plans that rely on large minorities of residential customers opting in to demand-response rates, even though there are important differences between such TOU rates and the needle-peak approach of critical peak pricing. The difficulty that California utilities experienced in attracting potential participants into the CA SPP also suggests that opt-in tariffs may not attract large groups of customers.

Some cite the experience of Puget Sound Electric, which offered an opt-out time-varying price during the western market crisis in 2001. Initially, 90 percent of customers remained on this rate.[193] By November 2002, however, the utility asked the regulator for permission to scrap the entire tariff as the result of public pressure from customers complaining that their bills were

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[190] Utilities and regulators will also need to know the likely demand response patterns of customers who will voluntarily choose to stay on the rate or opt for the rate, if taking service under the rate is not mandatory. This report does not address the issues involved in estimating these values.

[191] For present purposes, it is not important to determine who would present the pricing to the customers, regulators, utilities, both, or others.

[192] See, e.g., Ahmad Faruqui and Stephen George, *Quantifying Customer Response to Dynamic Pricing*, and Ahmad Faruqui et al,, *The Power of 5 Percent*.

[193] Lynne Kiesling, *Prospects and Challenges*, at 2.

slightly higher on the time-varying tariff than the standard rate (bills averaged 80 cents per month higher on the TOU rate.) Customers thus "opted out" en masse, rather than customer by customer.

7. What are the likely bill impacts from dynamic pricing, on average and for various subgroups of residential customers?

It is not possible to read any of the evaluations of the three pilots discussed here and come away with an understanding of the likely bill impacts of the tariffs and AMI implementation. This inconclusivity is a serious flaw in all the analyses, undermining their usefulness as guides to regulators in other states. A regulator may, of course, determine that an investment is cost-effective overall, and that the resulting tariffs fairly allocate the costs and benefits of the investment, even though there are winners and losers among the customers depending on their ability (or willingness) to take advantage of opportunities to avoid high-price periods. Regulators will want to understand the bill impacts on classes of customers and subgroups within each class, however, if for no other reason than to gauge the likely public response to approving (or mandating) the investment and related tariffs.[194]

One cannot simply look at the levels and percentages of demand response by customer group, and infer that bill impacts will correspond. The entire design of a tariff, and the usage patterns of different customer groups, have as much if not more to do with bill impacts as the customers' different responses to critical peak events.

In addition, not all the evaluations even attempted to estimate bill impacts.[195] Where evaluators did estimate bill impacts, they simply ignored the incremental cost of the meters (not to mention the additional costs that a full AMI installation would entail). Given that total meter costs can run as much as $7 per month (depending on the AMI configuration and the extent of back-office software revisions), and that operational benefits may not even cover 50 percent of such costs in some service areas,[196] ignoring meter costs is bound to skew the results of any bill

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[194] Strength of character is essential for a regulator, who must from time to time take positions that are unpopular but that advance principles such as efficiency. At the same time, regulators must manage their "political capital" well, in order to be successful in achieving policies consistent with such principles. In addition, regulatory principles have long included considerations of price stability and public acceptance. See James C. Bonbright, *Principles of Public Utility Rates* (New York: Columbia University Press, 1961), at 291; republished on the web (July 2005): http://www.terry.uga.edu/bonbright/publications.

Further, even where legislators have not required explicit consideration of affordability or universal access to service, regulators in a number of jurisdictions take care to limit the burdens of regulatory policy on vulnerable customers where they can.

[195] There are no bill impact analyses in the ESPP evaluations.

[196] As where a utility already installed automated meter reading (AMR), or where labor costs for meter reading are especially low, for example.

impact analysis. Further, even without accounting for metering and incremental AMI costs, the bill impact analyses presented in evaluations of the various pilots showed that some customers would see bill increases as a result of the institution of (mandatory) time-varying pricing.

Evaluations of the California pilot show that, not counting AMI costs, low-use customers of all income brackets studied enjoyed bill reductions as a result of the dynamic pricing offered to participants. Indeed, while they did not reduce their demand as sharply as did high-use participants, they enjoyed larger bill reduction benefits, again not counting AMI costs. These results bear out the advice of some AMI/dynamic pricing proponents, who note that because low-use customers have a higher load factor, they will benefit from the lower off-peak prices accompanying CPP, even if they cannot avoid as much usage on the peak as higher usage customers.[197]

Most high-use customers also enjoyed bill reductions in the CA SPP. However, one group actually saw bill increases overall. As can be seen in the chart below, lower-income/high use participants on average experienced bill increases, even though they reduced demand on average. The fact that this group included lower-income customers is reason for some concern. Further, the bill reductions experienced by the two lowest income groups of the high-use participants were effectively zero, even without counting the incremental costs of AMI investments, according to the Herter analysis.[198]

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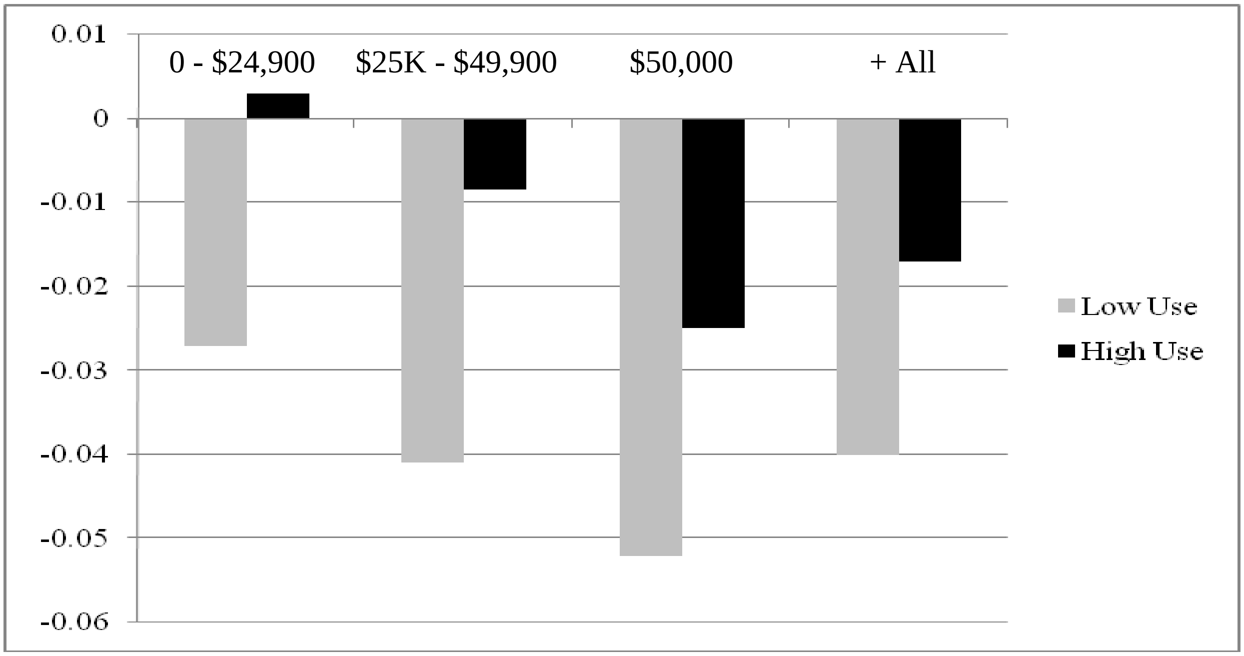
[197] *See, e.g.,* Roger Levy, *Demand Response: Tariffs, Rates and Incentives,* a presentation to the ACEEE Summit on Emerging Technologies in Energy Efficiency. October 27, 2006. Note, however, that in California, this relationship did not hold, because under the standard five-tier inverted block rate, very low-use customers enjoyed very low prices for their usage. SPP TOU and critical peak pricing eroded these price benefits. See, e.g., *PG&E AMI Final Opinion,* CA PUC Decision 06-07-027, July 20, 2006, at 46.

[198] *Residential Implications,* 2127-2128. Statistically, the bill differences observed for these participants were not significantly different from zero.

Figure XXVI: Mean Annual Change in Bills by Usage and Income (Without AMI Costs)



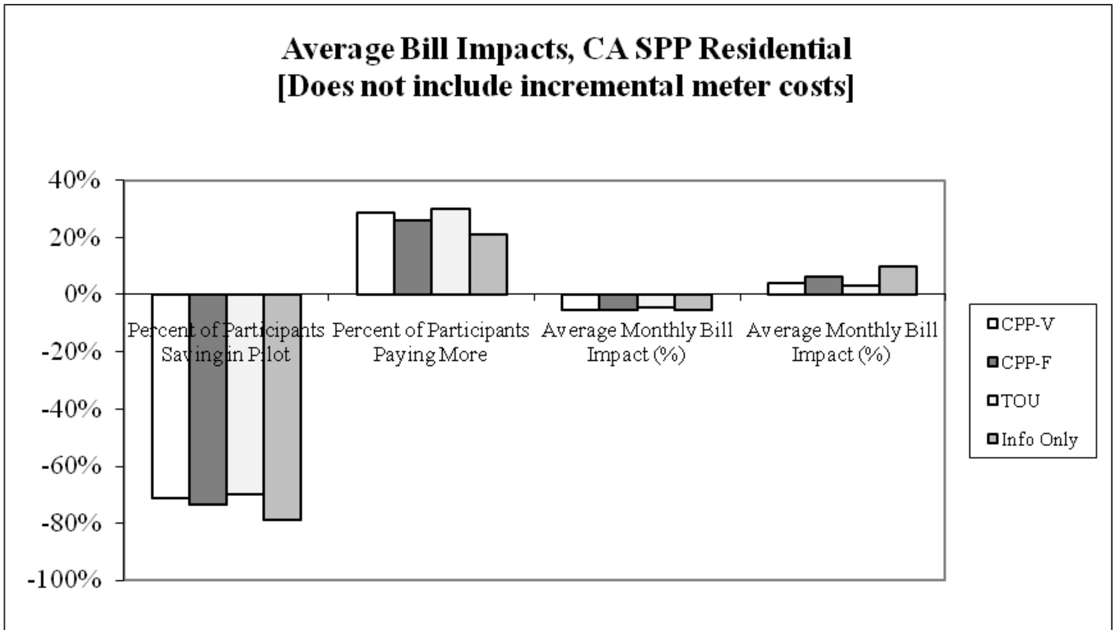
Source: Herter, *Residential Implementation*, Figure 5

Herter suggests that, given these findings, those considering a full-scale CPP implementation "might focus efficiency and education efforts on high-use, low-income customers."[199]

Twenty percent or more of the participants in all CA SPP pilot groups saw bill increases, even without counting incremental AMI costs. These results suggest that, at least in the absence of a CPR/PTR rebate option, there will be some net losers on time-varying rates.

[199] Ibid. Roger Levy also suggests collecting incremental metering costs on a volumetric basis, *Demand Response.*

Figure XXVII: CA SPP Bill Impacts by Tariff Type



The Ontario evaluators did not break out bill impacts by income or other participant characteristics. As in the California case, they ignored meter costs.[200] Without considering meter costs or conservation effects,[201] over the course of the experiment 75 percent of the participants paid less than they would have on the ordinary non-pilot prices. In August, however, the average bill impact across all three price-groups was an increase relative to what their bills would have been without the pilot pricing. It was also in August that the largest number of OSPP participants experienced a significant increase.

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[200] As noted above, in Section III, the utility was already recovering the costs of interval meters in rates as part of a government-mandated initiative to install such meters in every customer's premise. In August, Hydro Ottawa filed its Application for cost recovery of its advanced metering program with the Ontario Energy Board. The Application reflected the decisions of the Energy Board in December 2006 and the January 29, 2007 "Addendum For Smart Meter Rates" on allowed cost recovery of advanced metering required by the government policy. These orders prescribed a formula for calculating the cost of the advanced metering system, and required recovery of allowed costs through a uniform adder to the customer charge for all customers of a given utility. The Application reflected an increase from the 2006 rates (C$0.41/mo. for all residential customers and C$0.83/mo. for non-residential customers) to a uniform C$1.74/mo. for all customers. The U.S. and Canadian dollars are presently near parity. The Application is available at: https://www.hydroottawa.com/PDFs/HydroOttawa_APPL_20070208.pdf.

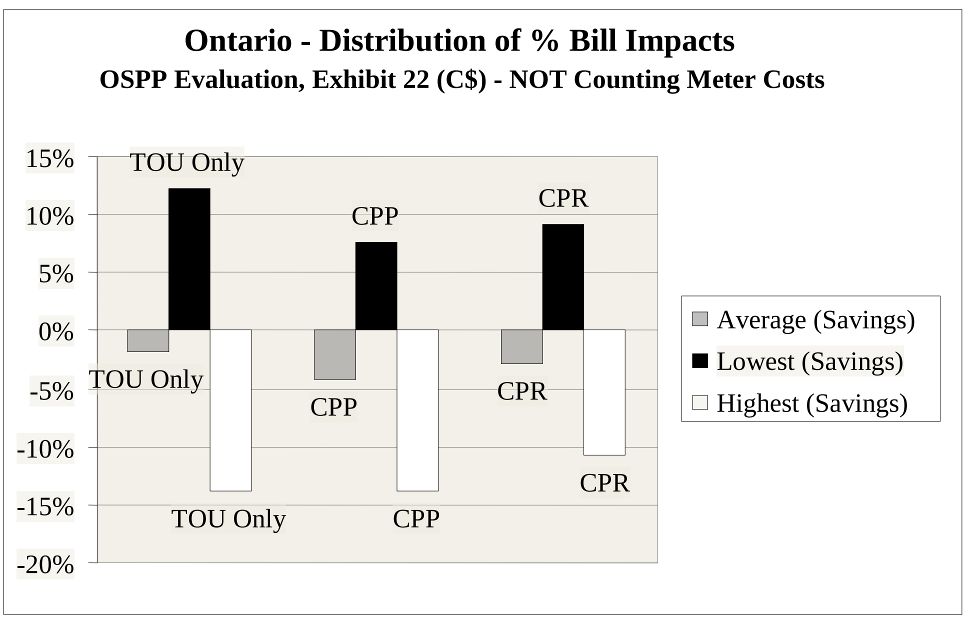
[201] But also not including the metering costs (which were considered sunk costs).

Such increases reflect the fact that for these Ontario participants, the higher pilot tariff peak prices did not encourage demand response. These August cost impacts were outliers, according to the Ontario program evaluators. Of the approximately 2625 statements issued over the course of the pilot, only 5 percent showed savings greater than C$8.84. Similarly, only 5 percent of statements reflected bill increases greater than C$3.46. Over the year, one participant experienced an increase as high as C$12.81, while some participants saw savings as great as C$35.55.

Assuming a 6.0 percent reduction in usage based solely on the conservation effect, and with an average price of C5.9¢/kWh, the evaluators estimated that conservation savings ranged from a few cents for the lowest volume user to over C$6 per month for the largest user.

The distribution of bill impacts reported for the Ontario pilot is shown in the chart below. As can be seen, on average over the entire pilot period, but again not including metering/AMI costs, participants saved on their bills. This was generally true whether they were on the TOU rate, CPP, or CPR. However, in each group, there were participants who experienced very large bill increases:

Figure XXVIII: Ontario SPP - Distribution of Bill Impacts (Excluding Meter Costs)



For the reasons discussed above, it is necessary to take the findings of pilot participant bill reduction with a grain of salt.[202] Failure to consider incremental metering costs calls into question whether these pilot results shed any useful light on the bill impacts of AMI in the case

[202] The OSPP finding of bill increases associated with peak usage increases is likely robust, however.

where a utility has no advanced metering in place. Even without correcting for this major defect in the analysis, it appears likely that in these analyses, participant bill savings are overstated, and that bill increases to at least some participants are understated. The evaluations also show that some customers, while perhaps a minority, will face sharp bill increases if dynamic pricing is introduced.

Further, assuming that the bill impacts observed in the pilots are representative of the impacts of a real implementation of AMI and related pricing, the question remains whether such results are consistent with sound or sustainable regulatory policy. Do these bill increases reflect the efficient allocation of costs to cost-drivers? If so, does equity (or long-term rate acceptability) require some mitigation of AMI-driven bill increases? It is not possible to answer this question in the abstract. Attempting the estimation of corrections to the bill impact analyses available deserves further research.

E. If past is prologue, critical peak and other time-varying pricing will produce "winners" and "losers."

As discussed above, not all participants reduced load, and in some cases participants' critical peak load went up during the pilot. For example, some ESPP participants did not show any load response at all to the pilot pricing option. As with the Track B (low-income San Francisco neighborhood) results in California, in the ESPP a small number of customers with large load responses drove up the average response rate.

We can view this fact as a glass half full, or a glass half empty. On the positive side, this experience suggests system-wide benefits do not depend on getting all or even most customers to respond to price signals; the strong response of a small number of customers can drive benefits for the entire system. On the negative side, system benefits are vulnerable to changes in the response of the few "star" responders.

Further, if it is necessary to provide potential star responders all the system benefits associated with their demand response in order to induce that very demand response, then non-responding customers will see higher bills (from any incremental AMI costs not covered by operational savings), but may be unable to create (and receive their share of) system resource benefits. Regulators must understand how likely it is that the utility will have to flow all system benefits back to demand responders, as opposed to setting critical peak prices (or rebates, as the case may be) at a lower level, thus allowing some of the system benefits of responders' demand reductions to flow to other customers and offset incremental AMI costs.

If there are groups of customers who cannot take advantage of demand response opportunities, but there are no system benefits to share with them because all such benefits must go to potential responders, then it will be more difficult to gain public acceptance for AMI. The pilots do not answer the question whether it is necessary to set critical peak prices equal to the avoided costs of critical peak usage.

The utilities in California set the critical peak prices in their respective service territories to meet three Commission goals, none of which included matching of the critical peak price with marginal cost at critical peak periods.[203] In Ontario, the critical peak price was set at a level intended to approximate the avoided costs of such usage. The C30¢ critical peak price was calculated as the average of the costs of the highest 93 hours of the previous year.[204] In Chicago, the Cooperative and ComEd designed the critical peak tariff to vary with day-ahead forecasts of system costs, up to a rate cap implemented to prevent extraordinarily high bill impacts.[205]

In the Central Maine Power alternative regulation case now pending, Dr. George testified that the full value of demand reductions would be $1.25 per kwh, whereas the utility proposed to set the critical peak rebate at 75 cents/kWh (implicitly leaving 40 percent of the avoided capacity benefit of their load reductions on the table for other customers). He further stated that a utility should be willing to provide 100% of avoided cost benefits to those who make them possible (here, by demand reductions).[206] But that argument presumes that it is both fair and feasible to ask all customers to pay for an infrastructure that only some will be able to use.

On the other hand, even low-income customers who have little load to shift may emerge no worse off from implementation of AMI, and taking service under a critical peak pricing tariff, than they were without such pricing. Such could be the result if (1) operational savings are a high proportion (e.g. 75 percent or more) of the total savings needed to justify AMI investment, (2) such customers have the typically flat load profile of low-use customers, and (3) not all such savings are needed as incentives to those who can shift. In such a case, bill increases from the incremental AMI costs may be offset by bill decreases for superior load profiles plus a share in

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[203] Consistent with PUC requirements, the utilities observed three key criteria in setting the critical peak rates: (1) maintain revenue neutrality for the average usage customer, (2) minimize bill impacts due to a change from existing rates to the pilot rate, and (3) provide a meaningful incentive for customers to reduce load. Interim Opinion in Phase 1 Adopting Pilot Program For Residential And Small Commercial Customers, *Order Instituting Rulemaking on Policies and Practices For Advanced Metering, Demand Response and Dynamic Pricing*, California PUC Rulemaking 02-06-001, June 6, 2002, available at: http://docs.cpuc.ca.gov/published/Final_decision/24435-03.htm.

[204] In the Pacific Northwest GridWise™ pilot, program managers set RTP customers' programmable thermostats to respond to price offers that changed every 5 minutes with changing system costs, according to a schedule of "comfort settings" that specified when the customer would reject the program price offer. If the price offer was too low to merit loss of the controlled end-use (water heating or space heating/cooling) according to the customer's comfort setting, the thermostat would "reject" the offer, and override the control. *PNNL Final Report*, at vii. Such a market approach could allow customers to shift load off peak at less than marginal costs. Determining whether this result occurred in the Olympic peninsula pilot is beyond the scope of this report.

[205] 2004 ESPP Evaluation Final Report, at ES-5.

[206] Stephen S. George, *Rebuttal Testimony on Behalf of Central Maine Power Company*, Docket 2007-215, Appendix A, p. 9.

the benefits of other customers' demand response. In a particular circumstance, the result could be no bill changes for low-use customers, or even decreases.[207]

Conversely, those who can shift large amounts will be winners. This result is likely to hold even if incremental AMI costs per customer are at the high end. The combination of high-use customers' share of operational savings, and the flow-through to them of at least a large share of the system resource cost savings their demand response creates, will likely more than offset their allocated AMI costs.

The California pilot results suggest that the customers in greatest danger of experiencing bill increases are low-income, high-use customers.[208] Pilot participants in this group, for reasons the pilot evaluations do not make clear, did not or could not shift enough usage off the critical peaks to avoid bill increases from the switch to a critical peak price.

The regulator may ignore the complaints of those who can shift without discomfort or danger, and choose not to do so.[209] The regulator will face a tougher set of choices if there are a number of customers who simply cannot shift their load, at least without serious discomfort, and whose load profiles mean they will see increased bills upon introduction of TOU or critical peak pricing.

Also, as is discussed above, these pilot results do not constitute conclusive proof that dynamic pricing and load control tariffs will bring forth similar levels of demand response, in other settings, with other customers, or over a longer period of time. A regulator will have to look behind the averages to the experience of subsets of customers, and look for data of response persistence, to understand whether such pricing will be valuable in other states.

F. Miscellaneous Additional Issues

As noted in Section I, above, this report has not attempted to address all the issues that a regulator will face when considering whether to approve AMI investments. Regulators may not find some of these issues readily resolvable, but nonetheless they will play a major role in determining the relative costs and benefits of AMI, and the public acceptability of the time-varying prices initiated using AMI technology. We merely list them below.

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[207] Such a result begs the question of whether such pricing could be achieved, with these felicitous results for small customers, without the entire AMI investment.

[208] This inference is not inconsistent with the ESPP observation that customers in multi-family units and customers without central air conditioning showed the largest response to critical peak price signals. Evaluator Summit Blue did not identify a group of low-income, high-use customers in this Chicago-area pilot.

[209] That is not to say that such customers will be powerless to exert political pressure on the regulator in any given instance.

1) What is the useful life of an AMI system installed today? What is its economic life? AMI technologies are new and evolving. How can we be sure of the length of their useful lives? If cost savings over years, if not decades, are necessary to justify the investment, is it prudent to go forward with the investment in the current state of technological development?

    a. To what extent should the Commission attempt to direct the selection of technologies, and associated functionalities? Should a regulator specify, for example, that the utility shall use a particular network architecture for the interactive communications component of a utility's AMI?

    b. Should a Commission encourage or require the system be open to use by non-utility parties?

2) What is the energy usage effect of dynamic pricing? What are the implications of such usage effects for generation fuel costs? For environmental compliance?

3) How do consumers get the benefit of energy and capacity avoidance, in states where most customers' power is procured through all-requirements contracts (such as are used in most restructured states with default service procurements)?

4) How should basic service procurement processes and contracts be revised to reflect allocation of the benefits of anticipated demand reduction?

5) How does demand reduction facilitated by AMI get credit, if at all, in regional power pools and markets?

6) Where a utility in a retail competition jurisdiction provides its non-shopping customers with monthly prices, rather than annual flat rates over 6 months or more, does it make sense to install a major new metering, data management, and communications infrastructure, when most of the benefits shown in at least one pilot came from avoiding the hedging premium that competitive suppliers add to bids for default service in that competition state?[210]

[210] Catherine McDonough and Robert Kraus, in their article "Does Dynamic Pricing Make Sense for Mass Market Customers?" *Electricity Journal*, Vol. 20, Issue 7 (August/September 2007), n. 22 and accompanying text, citing the *Direct Testimony of Bernie Neenan on Behalf of Citizens Utility Board and the City of Chicago*, ICC Docket No. 06-0617, October 2006, 21, to the effect that 83 percent of the benefits achieved via demand reductions in the ESPP pilot were attributable to avoiding the wholesale suppliers' risk premiums for flat rate default service.

7) To the extent that demand response is a means of hedging against premiums charged in the market by suppliers for flat rate service, are there better ways of reducing those market premiums?[211]

8) By what rate design should incremental metering costs be recovered?

   a. Flat rate per customer, as is now common for metering costs, or
   b. On a volumetric basis, to protect low-use customers?

9) How should ratepayers be assured of the benefits of reduced operating costs?

10) What limitations, if any, should be applied to a utility's use of remote termination and reconnection?

11) How should the critical peak price or the critical peak rebate be developed?

   a. Should it be set to flow the entire benefit of avoiding capacity to the demand-shifting customer, or should it be based on some other consideration?

   b. For example, should it be set only as high as needed to secure a desired level of demand response, with the balance of the avoided cost shared with the ratepayers generally? Used to hold vulnerable customer harmless? Shared with the utility or supplier as an incentive to foster demand response?

   c. How should the utility estimate the value of the resource costs avoided by the load shifting?

12) What is the extent of undepreciated meter, data management, communications, and other investments that would be rendered obsolete by the investment in AMI?

   a. Who should pay these costs? Ratepayers? Shareholders? Both, via some sharing, as is typical in the case of canceled plant? Should the answer to the question depend to any extent on whether the utility has demonstrated that the investment is cost-effective?

   b. Over what amount of time should abandoned meter and related costs be amortized?

13) How can analysts be encouraged to present data in a way that makes it possible to make comparisons between utility AMI implementations? For example, which manner of presentation of demand response results should analysts use: elasticities or percent load?

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[211] David Boonin, then-President of TBG Consulting, testified before the Pennsylvania Public Utilities Commission that the supplier premiums for hedging the variation in costs as they provide flat rate service to basic service customers are overstated by as much as 15 percent. *Comments on Mitigating Electric Price Increases*, Pennsylvania Public Utility Commission, M-00061957, June 2006. Mr. Boonin has since joined NRRI as the Chief of the Electricity division.

14) Should utilities be allowed pre-approval of AMI investments? If so, should regulators require an explicit sharing of the risk that costs will be higher than estimated by the utility, and benefits lower?

IV. Conclusions and Recommendations

A. What answers have we found to our key questions?

At the start of this report, we listed a number of key areas of uncertainty regarding time-varying pricing (offered using AMI) and residential customers:

1. To what extent did residential customers, on average, reduce load in response to time-varying pricing and direct load control in the pilots?

2. To what extent were the participants in the three pilots representative of residential customers, including particular subsets of such customers?

3. Did low-use or low-income customers respond to time-varying pricing differently from other customers?

4. How persistent, year over year, are the voluntary load shifts or reductions resulting from price signals, with or without smart meters?

5. If time-varying tariffs are voluntary, what portion of residential customers is likely to choose such pricing?

6. What are the likely bill impacts from time-varying pricing, on average and for various subgroups of residential customers?

Based on the information we have reviewed, we offer the following answers:

Figure XXIX: Summary of Answers to Key Questions

Question	Summary Answer
1	Overall, residential customers displayed significant demand reduction in response to critical peak prices. Customers with direct load control devices (such as programmable communicating thermostats) responded at dramatically higher rates (up to 41 percent on critical peak days) than those without such automated control devices (between 10 percent and 15 percent on average). Response of residential customers on average to time-varying pricing varied from group to group, and time to time. In some cases, the mean response was higher than the median (some particularly strong responders pulled the average response up). It is likely that within the averages, individual customers and subsets of residential customers showed widely varying responses to critical peak pricing. Not all responses to time-

	varying prices were demand reductions. In at least one pilot, participants on average increased usage during certain critical peak periods, despite critical peak pricing and critical peak rebate pricing. In one pilot, half the participants showed no response at all. CPR customers responded to critical peak rebate opportunities, but showed a lower response to critical peak rebate opportunities than CPP customers showed to critical peak prices.
2	Participants in the time-varying pricing pilots were roughly representative of the customer base from which they were drawn, but it is not possible to rule out self-selection bias in the results. Participants were in some cases skewed towards higher-usage, higher-income customers.
3a	Lower-use customers in general reduced their load by lower percentages than higher-use customers. One analysis of California results showed that low-use customers did not reduce loads at all in response to critical peak pricing; another analysis of the same data showed low-use customer response, but not at the same level as for high-use customers. Results were mixed for residents of multifamily buildings, who tend to be among lower-usage households - in the ESPP and OSPP, such customers at times responded more strongly than those in single-family homes. In the California SPP, residents of multi-family homes responded to critical peak pricing, but at lower levels than residents in single-family homes. Low-use customers of all income groups had the highest bill reductions, not counting AMI costs.
3b	Lower-income customers in general reduced load by lower percentages than higher income customers. Results are not definitive about the impacts of CPP or PTR on low-income customers, because income bands in pilot evaluations were not well defined. In one pilot showing strong low-income response, practically all the response came from a handful of customers. In the CA SPP, lower-income/high-usage customers increased usage on critical peak days.
4	The pilots do not provide a basis for estimating how persistent the observed demand responses will be year over year. Past experience with time-varying rates is discouraging on this point, but perhaps not indicative of likely persistence of response over time, given today's less expensive metering and demand response technologies, the ability to isolate high peak prices to a narrow set of critical peak hours, and the ability to program end uses to respond to prices communicated by the utility.
5	Pilots to date provide no useful information regarding the likely participation rates of voluntary time-varying tariffs. Optimistic estimates of 20 percent migration to opt-in time-varying rates and 80 percent opt-out retention rates have no basis.
6	None of the pilots provides readily available information on likely bill impacts of AMI, in that none addresses the allocation of incremental customer costs and time-varying resource cost savings to participants and non-participants. This omission is a major gap in the research to date, and hampers regulators trying to anticipate how an overall positive cost-benefit calculation for AMI will translate to specific customer groups. Findings of

	lowered bills from time-varying pilot prices must be discounted by the fact that the cost side of the equation ignored AMI costs. Even without counting AMI costs, 20 percent or more of the CA SPP participants on all pilot rates saw higher bills. In the Ontario SPP, 25 percent of the participants had no bill decrease, or had bill increases, on the time-varying tariffs. Among customers with higher bills in the Ontario SPP, CPR customers had larger increases than CPP customers.

The results of several pilots, then, show that residential customers, on average, have responded strongly to various types of dynamic pricing. Critical peak pricing, in particular, has shown promise as a demand response tool for residential customers generally.[212] Also, customers with uses suitable for load control, such as central air conditioning, and who have smart thermostats installed to automate the demand response to price signals, responded much more strongly than other groups. However, not all pilot participants reduced load, not all groups reduced load on average in every circumstance analyzed, and in some cases participants' critical peak loads went up during the pilot.

Bill impact information is necessary if for no other reason than to gauge popular acceptance of more dynamic pricing. Here, the pilot data is virtually useless, because none of the pilots reflected those incremental AMI costs that would be counted against incremental demand response resource cost savings. Even without reflecting this added cost, some customers experienced high bill increases at certain points in the pilots. For a variety of reasons, low-income, high-use customers in at least one pilot experienced large bill increases, again without considering the bill increases associated with that portion of AMI not offset by operational savings.

Also, only time will tell whether the results observed in these pilots will persist into the future.

Because of (1) the uncertainties over persistence of demand response under critical peak pricing or rebates, (2) the lack of specific information from the pilot reports about the identity of possibly vulnerable customers (making it hard to determine whether and if so how to mitigate potential harm to such customers), (3) the relatively small portion of estimated AMI costs that can be covered by operational benefits in some cases, and (4) questions about the extent to which those responding to critical peak prices must receive the entire benefit of their load reductions, leaving no benefit for other customers, it is not possible to conclude that AMI makes sense in all circumstances.

Greater efforts to induce persistent critical peak demand reductions are necessary, as future costs of capacity and energy are on track to keep going up. Whether AMI makes sense as the tool to incent demand response is very much open to question. As one utility official put it:

[212] This report does not focus on time-of-use rates, as such rates did not call forth the strongest responses in the pilots, and also can readily be implemented without investing in a complete advanced metering infrastructure.

> The root question is whether the goal is to install AMI (thus the question that started this discussion) or reduce generation levels and system peaks through conservation and/or DSM practices? Fully integrated AMI is not required to enable time-of-use and CPP rates nor is it required for most DSM programs. Several DSM programs add significant energy savings through [other means].[213]

B. Recommendations

As this report shows, residential customers on average can and do respond to time-varying prices. This experience, coupled with the understanding that AMI can offer large operational savings to many utilities, gives reason to hope that AMI's costs can be offset by cost reductions. There remains a great deal of uncertainty, however, regarding the persistence of demand responses induced by time-varying pricing. There remains uncertainty about net bill impacts on residential customers as a group if Critical Peak Pricing or Peak Time Rebates are offered, and if AMI is installed in order to support such tariffs. Further, there remains uncertainty about the useful lives of AMI components, and thus the net present value of AMI costs.

We acknowledge the uncertainties facing a regulator in evaluating AMI and its alternatives. There are two ways a regulator can resolve these uncertainties and decide what action to take: go ahead with AMI approval, or wait until experience elsewhere answers some of the questions about AMI's useful life and the persistence of resource savings from demand response initiatives undertaken using AMI. Neither approach involves authorizing further pilots.

Conducting a pilot at this point would duplicate work that has already been done and is being done elsewhere, without adding appreciably to the understanding of the remaining issues. It would instead be useful to analyze in more detail the vast amounts of information developed by the three pilots reviewed here (and the others mentioned in passing). Perhaps some of the questions could be answered with additional analysis. For example, it may be possible to do a better job of isolating demand response of low-income households, or estimating bill impacts for all residential customers under different assumptions about AMI costs and cost-recovery approaches.

Regardless of whether a regulator goes ahead with AMI approval or decides to wait until the persistence issues are better resolved, it would be useful to identify the vulnerable customers, and consider how a utility might enable them to avert any unfair impacts of an AMI investment, or even just a time-varying rate structure. This work needs doing. Even if it is done, however, the question remains as to whether the effects observed in these pilots will persist. Only time will provide the answer to that question.

In determining the relative costs and benefits of AMI and associated demand response initiatives, one key difficulty facing the regulator is that the arguments pro and con require a

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[213] Douglas Marx, Pacificorp, posting to EEI AMI listserv, September 2007.

determination of so-called "legislative fact," rather than mere "adjudicative fact."[214] In other words, the arguments center around what costs of the AMI and related investments *will be*, what consumer reactions *will be* to various pricing designs, how long such demand responses *will last,* whether and to what extent such changes in usage *will or will not* reduce the costs of producing electricity, what the operational savings from substituting AMI technology for meter readers and other labor *will be,* and whether changes in operations (particularly remote disconnection) represent an advance or a retreat for consumer protection *as a policy matter*.

Most of these issues require answers about what the future will bring. With respect to forecasting likely residential customer behavior, the answers may be based on examples from the past, or on regulators' beliefs about how consumers act in response to different types of prices, or on any other information from which inferences can reasonably be drawn. But the determination of this and the other cost-benefit issues requires the commissioner to make predictions. Such predictions are legislative facts, and cannot be determined in advance with certainty.

What remains is a choice about whether to lead consumers in taking on the AMI risks that time-varying pricing will not succeed as a demand response tool and that AMI costs will prove greater over time than now forecast.

There are enormous challenges facing regulators, electric utilities competitive suppliers and ultimately electricity consumers today: high incremental generation construction costs, high fuel costs, high incremental transmission and distribution infrastructure costs, new and potentially quite expensive environmental constraints on generation, to mention only a few. Some of these pressures are not likely to abate, and will instead intensify over time. Against this background, it could make sense for a regulator to pay some public goodwill and political capital out in the form of leadership in the area of demand response and operations technology, taking the risk that the uncertainties about the costs and benefits of AMI will be resolved against AMI's cost-effectiveness.

It is not likely to require as much political skill to persuade utilities, consumers and other stakeholders to accept time-varying pricing as it has been historically. According to the pilot results, participants expressed satisfaction with pilot time-varying pricing by overwhelming

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[214] According to Kenneth Culp Davis, groundbreaking author on administrative procedures:

> Adjudicative facts usually answer the questions of who did what, where, when, how, why, with what motive or intent... Legislative facts do not usually concern the immediate parties but are general facts which help the tribunal decide questions of law and policy discretion.

Kenneth Culp Davis, Administrative Law Treatise (1st ed1958), § 12:3 at 413, cited in Richard M. Levin, *The Administrative Law Legacy of Kenneth Culp Davis*, Washington University in St. Louis, School of Law, Faculty Working Paper Series, Paper No. 04-06-02, June 15, 2004, at 5.

majorities. Some of the historic common sense arguments against time-varying pricing need to be re-examined. Contrary to common assumptions about who can take advantage of peak pricing signals, residential customers in more than one dynamic pricing pilot have successfully lowered demand in response to critical peak pricing. Even low-use and low-income customers have, on average, lowered usage significantly in some circumstances. Low-usage customers also benefit from a relatively flat load shape. It is, in principle, possible to identify and assist customers who are both low-income and high-usage, to prevent them from experiencing major bill increases as a result of an AMI investment and subsequent implementation of time-varying prices.

On the other hand, a regulator could look at the same data and conclude that, at least until some years pass (and demand response from California customers and those in other jurisdictions implementing time-varying pricing remains strong), demand response should not be counted towards the benefits of AMI. In the meanwhile, the regulator should encourage other forms of utility demand response activity.

For example, the dramatic results for customers with programmable communicating thermostats (producing demand responses 50 percent higher than prices alone) may well be achievable by direct load control, implemented without the interposition of AMI's advanced meters and sophisticated communications networks. Similarly, critical peak pricing and rebates could be offered on a targeted basis to customers most likely to respond strongly, using advanced meters but not the rest of the AMI technology. Especially where a utility already has harvested labor savings from automating the meter reading function, AMI may not be cost-effective, and these other alternatives should be pursued.

The best course will vary from service area to service area, from utility to utility, from time to time. Doing nothing about demand response is not an option, in light of the enormous costs that a small amount of peak load shaving can avert. This author tends to be cautious, and considers that utilities seeking approval to recover major investments in rates without a reliable cost-benefit justification should shoulder the risks associated with the uncertainties that remain. With this background in mind, the following are some recommendations that emerge from this review of issues surrounding AMI for residential customers:

Figure XXX: Recommendations

1. Where automated meter reading has already been installed, regulators should not authorize cost recovery of Advanced Metering Infrastructure until results from California and other states with widespread AMI and time-varying rate options demonstrate persistent and large resource savings from time-varying rates.
2. Regulators should require a full analysis of the merits of AMI whenever a utility requests cost recovery.
3. Where the analysis of costs and benefits of AMI leaves doubt about its net value, regulators should require utilities to take the risks associated with such uncertainty, if they wish to move ahead with AMI.
4. Regulators should not require further pilots before implementing or deciding not to implement AMI.

5. Regulators who have decided not to authorize expenditures on AMI at this time should require periodic updates from utilities concerning levels and persistence of demand responses among customers of utilities with ongoing pilots or full-scale implementation of AMI, and updated information available as to the impact of such AMI investments and any time-varying pricing plans implemented using such AMI on residential customers generally, and on especially vulnerable customers in particular.
6. Regulators should require utilities to develop and implement aggressive, cost-effective demand-response programs, including efficiency as well as Direct Load Control.
7. Regulators should seek access to underlying data on pilots that have been operated to date, and arrange for this data to be analyzed to develop reliable estimates of (a) bill impacts of AMI and time-varying pricing on different groups of residential customers, and (b) the extent to which customers reduced their demand by taking steps that would be difficult to take year after year.

Appendix: Further Reading

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