argument stems from the assumption that markets for energy (including oil, natural gas and coal) are inextricably linked such that conservation in any one market that leads to increased efficiency in our use of energy sources will ultimately decrease our dependence on foreign sources and hence decrease our vulnerability to outside pressures (economically) and threats (geopolitically). His calculations result in a national security adder of 0.57¢ to 1.14¢ per kWh.

9.3 Summary

If a utility or regulatory commission wishes to incorporate into its benefit-cost analysis the externality benefits from reduced energy consumption resulting from demand response and conservation, it needs to first determine the appropriate adder and then apply it to the kWh saved as a result of the program being implemented. Relating externality benefits to demand response and conservation activities enabled by Smart Metering can be tricky. If demand response results in shifts in load from peak to off-peak times of the day, a production trade off may result where more generation comes from older, less efficient base load coal plants that emit more pollutants. This possibility needs to be carefully considered in the estimation of these benefits.

[75] Cicchetti in the working paper, "A Primer for Energy Efficiency,". draws from Leiby, P., Jones, D., Curlee, R. Lee, R. November 1, 1997. Oil Imports; An Assessment of Benefits and Costs. Oak Ridge National Laboratory. ORLN-6851.

10
SUMMARY

Smart Metering can expand the value consumers realize from investments in conventional electricity infrastructure assets in a number of ways. In addition to the cost savings that the utility realizes, additional benefits may accrue to consumers, which are called societal benefits because by their nature some of them may accrue to all consumers to the general benefit of society.

The installation of Smart Metering technology by itself does not produce societal benefits. Rather, Smart Metering serves an enabling role when combined with other initiatives, such as the implementation of demand response programs, the revision of outage restoration practices, and the adoption of devices that communicate consumption and price/event information to consumers. Additional benefits are attributable to the energy and demand changes that result from change in consumption behavior, including lower environmental impacts and improvements in employment and wages in the local economy. Quantifying societal benefits requires sorting these streams of benefits in a way that characterizes them by the source so that proper value transformation function can be applied. If this is accomplished, then benefits arising from different sources may be monetized and accumulated to provide an overall measurement of benefits.

Figure 10.1 provides a summary of the processes by which these benefits are generated and to who they accrue. Because the primary benefits in some cases are measured in different ways, methods and protocols are needed to transform the physical manifestation into monetary terms. As the figure illustrates, there are four sources of directly attributable benefits and two forms of spillover benefits.

Quantifying the Societal Benefits Attributable to Smart Metering

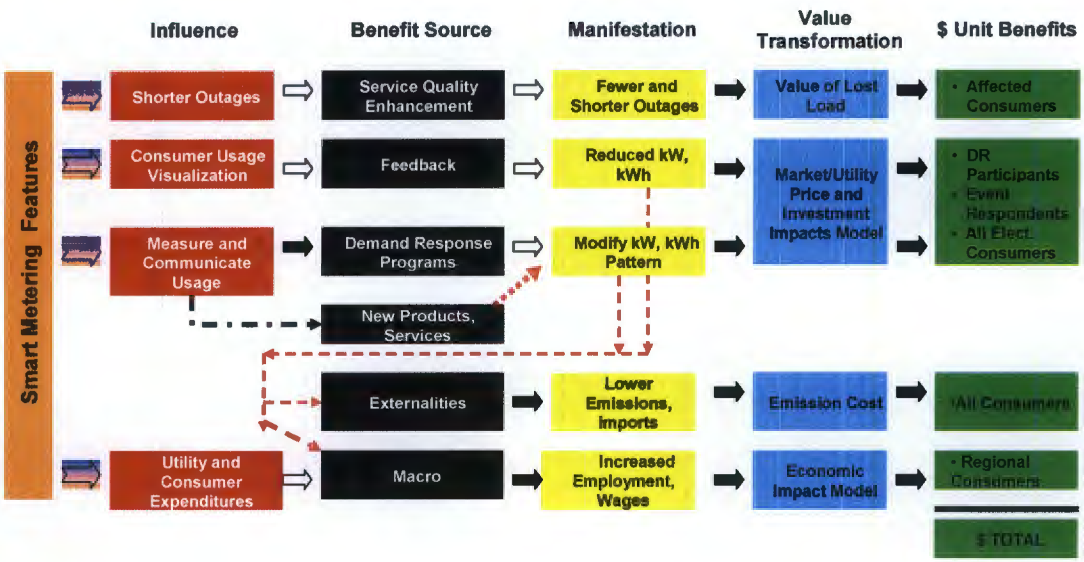

Figure 10-1
Source and Measurement of Societal Benefits

The direct benefits are as follows:

- **Service Enhancement**. Smart Metering includes features that are the enabling factors, labeled as influences in the figure. By providing the utility with better information about the nature and extent of outages, Smart Metering influences the duration of outages. This benefit is manifested as improved service quality, i.e., shorter outages. One way to monetize these benefits is to use the value of lost load (VOLL) which equals the benefits (measured as kWhs of restored energy) times a measure of the value ($/kWh) consumer realize. Those affected by an outage are the direct beneficiaries. However, since every consumer is potentially exposed to an outage, these benefits may be treated as accruing to all electricity consumers since they all are presumably exposed to outages and the associated undesirable consequences.
- **Feedback**. Metering load at a very fine level of granularity (over hourly or shorter intervals) and making those readings available quickly and conveniently to consumers (direct feedback), may cause some of them to reevaluate how they use electricity and result in lower electricity usage. The benefits of this outcome accrue to those participants that reduce usage, but the benefits may also inure to all other electricity consumers.
- **Demand Response**. More precise metering and meter reading enables an increased scope and scale for demand response programs, which is manifested as load profile modifications measured as energy and demand changes. Like feedback, these modifications can trigger market adjustments that end up benefiting demand response participants and consumers in general.

- **New Products and Services**. Smart Metering can expand the scale and scope of the series that are provided by an electric utility creating, thus enhancing customer service and satisfaction and possibly resulting in additional revenues.

Other benefits are not realized directly, but are spillovers benefits, as indicated by the dashed lines in the figure. In those cases where energy and demand usage is modified, there are two additional potential streams of benefits:

- **Externalities.** Changes in energy and demand attributable to feedback and demand response, themselves enabled by Smart Metering, affect the sources of generation used to serve electricity demand and, to the extent that emissions are lowered or oil imports are reduced, possibly resulting in societal gains that all consumer enjoy, again demonstrating a collateral impact that affects sectors other than electricity.
- **Macroeconomic Impacts**. Behavioral changes enabled by Smart Metering can lead to macroeconomic impacts, including local economic activity such as changes in employment and wages that can potentially benefit all regional consumers.

The value transformation function associated with each benefit stream converts the physical changes in the level of electric service or the nature of economic activity into monetary terms. The nature of that function and the parameters used are critical elements of the valuation process. As portrayed in Figure 10.1 and demonstrated in Section 4.5, a chain of linked assumptions is required to get to that point. These assumptions are subject to considerable subjectivity in the process of parameterization and measurement and further widen the range of values that characterizes the final monetized level of benefits This ambiguity and uncertainty are part of the landscape. As more experience is gained in characterizing behavior, the range of attributed benefits will narrow. For now, the analyst is left with determining how to convey to decision makers the inherent uncertainty.

A
APPENDIX A – FUNDAMENTALS OF THE PRICE ELASTICITY OF ELECTRICITY DEMAND

To develop a synthesis of price elasticity that provides actionable results, the only EPRI studies considered were those that provide estimates of price elasticity employing models or methods that are consistent with economic theory and that used observed (not simulated or synthesized) price response from pilots and experiments to estimate the demand for electricity. This screening resulted in nine residential own-price elasticity studies and 18 time-differentiated pricing studies, eight of which involved residential consumers and the remainder either commercial and industrial consumers, or both.

The discussion that follows focuses on the results of these chosen studies because they constitute values that would likely be received as credible and representative of what can be expected under today's consumer and market circumstances if used in a Smart Metering business cases to quantify demand response impacts. For the most part, the studies reflect the actions consumers undertake using available technology. For this reason, these behavioral representations may underestimate what could be achieved if consumers were provided with better technology and information to assist responding to price changes. In fact, the results of some recent pilots suggest that such technology could have a large impact on how consumers respond to price changes.

The EPRI study reviews both own-price and substitution elasticity estimates. Smart Metering technology is expected to enable the widespread introduction of time-varying rates that induce customers to change their electricity consumption in ways that benefit them and others. The following review of price elasticity estimates therefore focuses on estimates that are associated with demand response programs that feature time-varying prices or other inducements to adjust consumption.

A.1 Household Shifting Price Elasticities

Estimates of the elasticity of substitution for the residential sector vary widely, with variation mainly attributable to differences in appliance holdings (Caves, et al., 1984; Caves, et al., 1989). For instance, the five residential TOU pilots funded by the U.S. DOE during 1977-1980 found that the typical within-day elasticity of substitution was 0.14, but that it varied by 50% in either direction (from 0.07 to 0.21) based on household appliance holdings (Caves et al., 1984).

The residential TOU program deployed by Midwest Power Systems from 1991-1992 found that households with all major appliances had a within-day elasticity of substitution 0.39,[76] while those with no major appliances exhibited no shifting, resulting in an estimated elasticity of substitution value of zero (Baladi and Herriges, 1993). The recent large scale residential CPP-Fixed experiments in California Statewide Pricing Pilot (SPP) reported a statistically-significant elasticity of substitution of 0.11 for households with central air conditioning, but a value of only 0.04 for those without (Charles River Associates, 2005).

A.2 Businesses Shifting Price Elasticities

TO judge from the selected studies summarized in this synthesis, commercial and industrial (C&I) consumers exhibit considerable heterogeneity in electricity price elasticity. The differences are associated with variations in customer circumstances, such as business activity, peak and overall consumption level, and the availability of on-site generation equipment. For example, the RTP pilot of the Niagara Mohawk Power Company (NMPC) in 1985-7, which involved large (over 2 MW) industrial consumers, found that the average elasticity of substation was to 0.09; but there was considerable variation among participating firms, from zero to over 0.16. Moreover, 10% of the firms provided most of the response (Herriges, et al., 1993), and an equal percentage was non-responsive.

Goldman, et al. (2005) revisited the NMPC market 20 years later to assess how these firms (over 2 MW) had adjusted to RTP as the default service rate. They report that while the portfolio (all participants) average elasticity of substitution was 0.11, there was significant variation among business category: 0.16 for manufacturing, 0.10 for government/education, 0.06 for commercial/retail, 0.04 for healthcare, and 0.02 for public works. Moreover, they reported that 15~20% of consumers accounted for 80%of the usage reduction. Duke Power's RTP pilot of larger C&I firms confirmed both of these findings: the study reported an average hourly own-price elasticity of 0.21 for textiles firms, but the portfolio of over 100 consumers exhibited a substitution elasticity almost 33% lower (0.15). Firms with an on-site generator or arc furnace, however, exhibited a substitution of elasticity 0.26 while those without exhibited 0.02 (Taylor, et al., 2005).[77] These results are yet another confirmation of the inherent heterogeneity among the price responsiveness of firms.

Size-related heterogeneity is supported by the CPP-Variable experiments for small C&I sectors that were conducted in the California Statewide Pricing Pilot (SPP). From the CPP-Variable experiment, Charles Rive Associates (2005) found that the firms with peak demands between 20kW and 200kW showed an average elasticity of substitution of 0.07 and those with peak demands less than 20kW the estimated elasticity was almost identical (0.06). However, elasticity

[76] Note that this estimate is much higher than the others. This may be because the study was restricted to a single market with the same price change so that extraneous factors that affect electricity usage were not very different across consumers. Studies that aggregate data from several time periods and jurisdictions tend to exhibit lower estimates because it is difficult to sort out the price effect from all of the other systematic variations being correlated with the price effect.

[77] Substitution elasticities are reporter here as positive values, although some researchers report them as negative values.

increased with the average daily usage of the latter group consumers—large usage customer were more price responsive but not nearly so much in the case of former group.

Ownership of energy substitutes was found to have a significant impact on price response in some studies. The aforementioned Duke Power RTP pilot found that the average hourly own-price elasticity was significantly higher when the firm operated an on-site generator (Taylor, et al., 2005). Moreover, firms with on-site generation exhibited significantly high estimates of within-day elasticity of substitution, ranging from 0.26 to 0.32, while those without it exhibited very little substitution capability (Schwarz, et al., 2002). Goldman, et al., (2005) also found, based on the NMPC's RTP program, that consumers with on-site generation exhibited higher exhibited price elasticities, in some cases twice as high. O'Sheasy (1997) reported that larger firms served under RTP at Georgia Power that had on-site generation exhibited a higher level of price response.

A.2.1 Impact of Enabling Technologies on Price Elasticity

Recent analyses of pilot results provide indications of the extent to which enabling technologies enhance electricity price elasticities. GPU's residential CPP-Fixed program included a treatment involving the installation of interactive controllable thermostats. The estimated elasticity of substitution for the treatment group was approximately 0.38, 2-3 times higher than that of the TOU-only treatment (Braithwait, 2000).

Analysis of the CPP-Fixed and CPP-Variable programs that were implemented as part of the California SPP found that peak reduction impacts were significantly higher with smart thermostats than those without the technology. In one instance, Charles River Associates (2005) attributed about two-thirds of the peak reduction to the enabling technology and the remainder to price-induced behavioral response. American Electric Power (1992) reported large load shifts with the aid of an interactive communication technology called TransText (Faruqui and George, 2002). Both of these pilots involved relatively few participants and produced results whose elasticity estimates are characterized by low statistical significance. They offer enticing, but as yet unestablished evidence of the role of available enabling technologies in the short run.

Faruqui et al. recently compared the results of recent pilot studies to illustrate differences between demand response program designs and the impact associated with providing participants with some form of technology to make response easier. Figure A.1 represents the results. Clearly, the response, measured in terms of the average percentage reduction in residential participants' usage during events, suggests that technology makes a difference. A latter section of the report addresses the challenges in employing percentage changes for individual studies unadjusted for price and program features differences as a means for quantify demand response program. However, even controlling for design difference, it appears that enabling technology makes a difference: it augments the intensity of the price response. This result is to be expected. In many cases, the technology provided to the participant is a thermostat that allows the consumer to save energy by timing air conditioning services with household occupancy; and in some cases it is configured so that the program implementer can manage the operation of the AC unit during events by turning equipment off during an event or cycling it on and off. If the external control aspect can not be overridden, then a response is assured.

Figure 2. Estimated Demand Response Impacts by Experiment (from Faruqui et al, 2008)

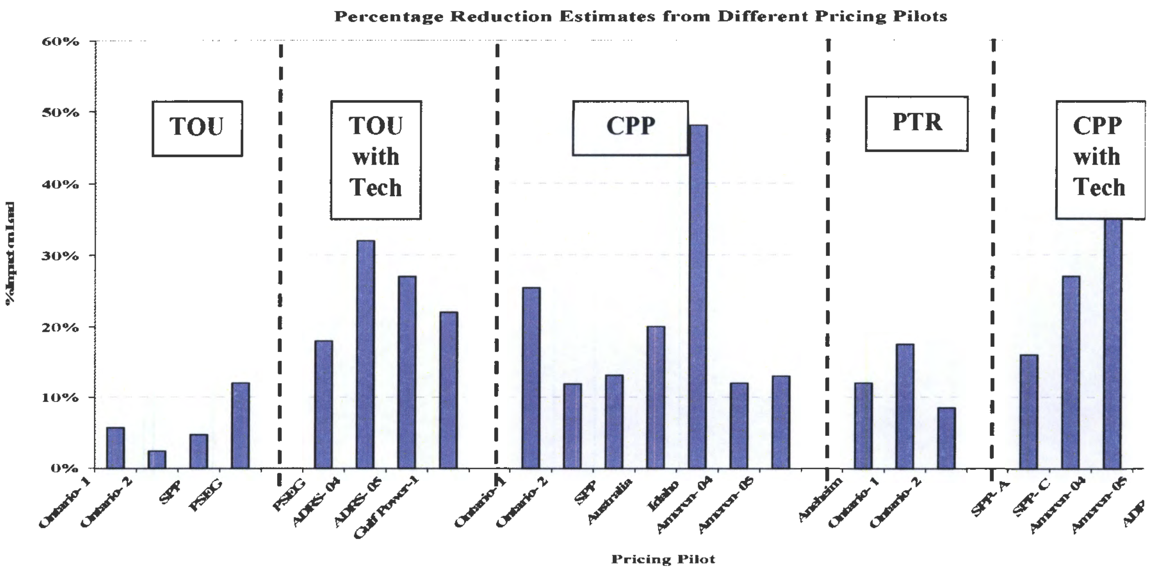

Figure A-1
Estimated Demand Response Impacts by Experiments (from Faruqui et al, 2008)

A.2.2 The Effects of Learning and Experience on Price Elasticities

A few studies have examined how the price elasticities for time-varying rates would change with experience. Taylor and Schwarz (1990), basing their work on the analysis of time-series data from Duke Power's residential TOU rate, which involved both energy and demand charges, found that over time participants exhibited an increase in the own-price elasticity of maximum demand, in the cross-price elasticity of peak energy with respect to the demand charge, and in the substitution of off-peak for peak energy. Schwarz et al. (2002), basing their work on Duke Power's eight years of RTP experience, reported that the firms with an hourly elasticity of substitution just under 0.2 in 1995 exhibited an increase to 0.25 by 1999, which they attribute to learning.

Price elasticities of electricity consumers on rate programs may change as the institutional context of the programs changes over time. An aggregated-level analysis for U.S. households on non-TOU rates revealed that long-run own-price elasticity for electricity demand had declined steadily from -2.1 to -1.2 during the period 1950-87 (Chang and Hsing, 1991). This decline in price response may reflect a growing dependency of households on electric devices that provide convenience and entertainment, devices for which there are few direct substitutes. However, a more comprehensive study is needed to clarify how long-run adjustments to prices and other factors affect short-run price response.

Faruqui and George (2005) note that current level of price elasticity in California is lower than what was reported for California about a quarter century ago. The reduction in price elasticities over time may be attributable to California's aggressive promotion of energy efficiency measures, conservation programs, and load control programs, which have lowered consumer capability for price response. However, resolution of the issue of whether in the long run the elasticity is lower or higher waits a more comprehensive study.

A.2.3 Impact of the Price Level on Price Elasticity

Many demand analyses employ a functional representation of electricity demand that imposes on the statistical estimation process the presumption that electricity usage changes are due solely to a change in the price ratio and not to changes in the nominal level of price. This assumption implies that the price response to off peak prices of $.10/kWh and peak $.30/kWh is the same as the response to prices of $.20/kWh off-peak and $.60 peak/kWh, because the price ratio in both cases is identical, i.e., 1:3.

Recent developments in the measurement of price elasticity suggest that price elasticity values may vary with the level of electricity prices or be subject to price and quantity thresholds. This phenomenon may result because electricity consumers are only managing in response to price changes a limited set of electricity-using devices those that are deemed to be discretionary. As discussed previously, this situation is analogous to a kink in the demand curve that results in constrained price response. If this case, it is important to understand how the constraint is manifest in order to predict how consumers respond to price changes over the full range of prices.

Gupta and Danielson (1998) found that consumers with on-site generation responded significantly to RTP rates but only above a specified price threshold. This threshold effect was also investigated by Schwarz, et al. (2002) in connection with Duke Power's RTP program. They found that consumers with on-site generation started to respond to price only when the nominal level reached $0.05/kWh, which resulted in estimated substitution elasticities of zero below $.05/kWh and a substitution elasticity of 0.25 at prices in excess of that amount. Goldman, et al. (2005) found that a few (about 10%) consumers exhibit higher price response at higher nominal prices, but the difference was only 15% or less.

B

APPENDIX B - THE STRUCTURE OF AN INPUT-OUTPUT MODEL OF AN ECONOMY

The purpose of this section is to describe the methods that could be used to estimate macroeconomic impacts that stem from the installation of Smart Metering by electric utilities. These macroeconomic impacts refer to the *direct*, *indirect*, and *induced* changes in employment, state-level income, and value added that result from: 1) direct investment expenditures on Smart Metering; 2) reallocation of cost savings by the utility; and 3) changes in the final consumption of goods and services by customers from the bill savings from new products made possible by the investment in Smart Metering, such as conservation and demand response programs.

Since such an analysis would require an input-output (I-O) model of the entire State's economy, this discussion provides a brief introduction to the typical modeling software and databases from which such an I-O model could be constructed. As discussed below, the distribution of economic impacts is often as important as their magnitude. To appreciate this fact, it is important to understand what is involved in deriving these types of macroeconomic impacts. This issue is discussed next.

B.1 Methods for a Macroeconomic Impact Analysis for Investments in Smart Metering

Input-output (I-O) analysis, developed in the late 1930s and early 1940s by W. Leontief, has since proven to be an effective way to assess the economic effects from expenditures made as part of economic development and public policy initiatives at the national, state, and local levels. In contrast to more aggregate analyses, I-O analysis has the ability to differentiate the effects of policy initiatives by important economic sectors.[78]

B.1.1 Accounting for the Total Economic Effects

The I-O model provides an insightful way to depict and investigate the underlying processes that bind an economy together. Its strengths lie in a detailed representation of: 1) production (primary

[78] As is the case with more conventional macroeconomics, I-O models are a special form of general equilibrium analysis; but they differ in at least one important respect. Conventional macroeconomic models trace changes in aggregate economic indicators such as national income, gross national product employment, and investment due to changes in taxes, and spending. However, these models do not address the composition of these changes by production sector, nor do they trace the resultant effects throughout the economy. Since there is no reason to believe that the effects of the investments in AMI and associated demand response programs are distributed evenly throughout the economy, an I-O analysis is needed to trace these changes throughout the various sectors of the economy.

and intermediate input requirements), 2) distribution (sales) of individual industries in an economy, and 3) the interrelationships among these industries and other economic sectors of an economy. The methodology's analytical capacity lies in its ability to estimate the *indirect* and *induced* economic effects stemming from the changes in *direct* investment or policy expenditures that lead to additional *indirect* and *induced* purchases by final users in an economy.

These *indirect* and *induced* changes in economic activity result from what are now commonly known as "multiplier" or "ripple" effects throughout the various sectors in the economy. An initial expenditure of one dollar in one sector sets in motion a cascading set of impacts in the form of additional expenditures in other sectors by each business whose sales have increased; it is the cumulative impact across all affected businesses or industries that are of most interest. Depending on the nature of the change in initial direct expenditures, these *indirect* impacts could be in the form of additional purchases of a variety of goods and services, for example: 1) raw materials and primary factors of production, 2) semi-finished or intermediate goods, or, 3) capital equipment. Moreover, the initial changes in investment or program related *direct* spending and resultant *indirect* increases in business spending are associated with changes in output or sales, changes in employment and income, and changes in payments to land, capital, and other primary factors of production.

Part of these *direct* and *indirect* effects is in the form of the increased labor income generated in the economy due to the increased economic activity. To the extent that part or all of this additional income is spent within the economy, there are some additional "ripple" effects that are now commonly referred to as *induced* impacts; and they also can be estimated using the I-O methodology. The magnitudes of both the *indirect* and *induced* effects differ by economic sector.

At the most basic level, input-output models require that the *direct* changes in purchases or expenditures must be specified in the form of additional purchases by final users of products. However, in some impact analyses, some of these *direct* effects may also be in the form of intermediate purchases by production sectors of the economy or changes in consumption patterns by households or input use by firms, particularly of energy. Rather than being reflected in changes in sales to final users, these types of *direct* effects potentially change the structure of the input requirements for some sectors of the economy.[79] A bit more is said about these effects below.

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[79] Batista, et al. (1982) addressed similar issues in restructuring a model of the State's economy in an earlier study for NYSERDA to assess the economic impacts from potentially new biomass energy production industries. The study involved estimating the direct, indirect, and induced employment impacts from introducing an entirely new sector into the economy whose technology and input structure were estimated from detailed engineering plant designs. The economic impacts clearly differed by region: they depended on the size of the plants, as well as the extent to which the biomass feedstock could be grown locally or had to be imported from other states. In yet another study, Blandford and Boisvert (1982) were concerned with isolating the direct and indirect employment implications that result from exporting agricultural commodities in processed versus raw form. This analysis involved examining individual coefficients of the I-O model to identify the raw agricultural commodity component of various processed agricultural commodities so that the direct and indirect impacts for both sectors could be put on a comparable basis. It is clear that the additional employment due to processing differed by region of the country based on where the raw products were grown and where the processing was done.

B.1.2 Identifying the Total Economic Impacts of Investments Smart Metering and DR Programs

Through the use of a couple of well-designed flow charts, it is quite easy to describe the process by which one can estimate the total economic impacts from investments in Smart Metering and the associated DR programs. Three things must be emphasized at the outset. First, while the social benefits are critical to any comprehensive evaluation of these kinds of initiatives, it is the private benefits and costs—those that translate into specific financial gains or losses—that lead to macroeconomic impacts. Second, in order to evaluate the economic effects, a Base Scenario that represents the situation without the Smart Metering investment and DR programs must also be identified. Finally, to identify the macroeconomic impacts, it is helpful to think of the introduction of Smart Metering as a process that consists of two distinct phases.[80]

The first is the installation phase in which the central hardware and software are purchased and installed, along with the smart meters for customers. The second phase occurs once the demand response programs and other new products have been implemented. In reality, these two phases are not absolutely distinct, particularly if some customer classes or regions are given priority for meter installation and DR program implementation. However, the important point is that investment costs and the costs associated with meter installation are one-time expenditures, and the impacts of these expenditures will be short lived. In contrast, the operational savings to the utility once the system is installed and the bill savings to the customers from DR programs will persist into the future. Thus, the macroeconomic effects are modeled separately, and an appropriate Base Scenario is developed for each.

Phase I: The Installation. This first phase is depicted in Figure B.1, where the top panel represents the installation phase, while the bottom panel is for the Base Scenario without the investment. The two critical activities in Phase I are the installation of Smart Metering hardware and software at the utility and the installation of customers' meters. These activities are represented in the boxes at the far left of Figure B.1. The process by which the macroeconomic impacts come about can be understood by following the arrows. Smart Metering installation leads to direct increases in purchases of equipment, engineering services, technical assistance, as well as the purchases of meters and the labor and other inputs needed for meter installation. These direct purchases are made from various sectors of the economy. Once they are distributed among the sectors, one can use the analytical capacity of the I-O model to calculate the additional indirect and induced "multiplier effects" from such one-time increased spending. Then, it becomes possible to calculate the total increased effects on sales, income, value added and employment resulting from the initial direct expenditures.

Depending on the extent to which the cost of the smart meters is totally or partly passed on to the customers at this stage, customers' bills may increase, although electricity usage will remain the same. Although the costs of smart meters may be borne over a period of years, they are one time costs, and it is assumed any cost to the customer results in a one time increase in the utility bill—altering this assumption would only complicate this conceptual model. As shown by following the arrows, increased utility bills will lead to reductions in direct consumption spending by

[80] This is also the strategy used by Batista, et al. (1982) where there were separate economic assessments of the construction phase and operations phases.

customers. This reduced spending is distributed appropriately across sectors in the economy as reduced spending on food, a variety of services, fuel, housing, and other products and services. Then, through the analytical capacity of the model, it is possible to calculate the reduced indirect and induced "multiplier effects" that stem from the direct reductions in consumption expenditures. Next, the resulting total reduced effects on sales, income, value added and employment are calculated. Finally, the *net* macro economic effects from Phase I are calculated by subtracting these reduced effects due to increased bills from the total effects due to new direct spending by the utility.

Since this investment phase involves some new direct spending on equipment and other items and an increase in customer's bills only if part of the cost is shifted from the utility to them, defining a Base Scenario against which to compare these macroeconomic effects is rather straightforward. The Base Scenario is illustrated in the bottom panel of Figure B.1, where customers' bills as well as electricity purchases are simply at their original levels. The total economic impacts simply result from the initial direct consumption expenditures of the customers relative to what they would have been had the utility not shifted part of the cost of the meters.

. Economic Impacts for AMI and Resulting Demand Reduction Programs

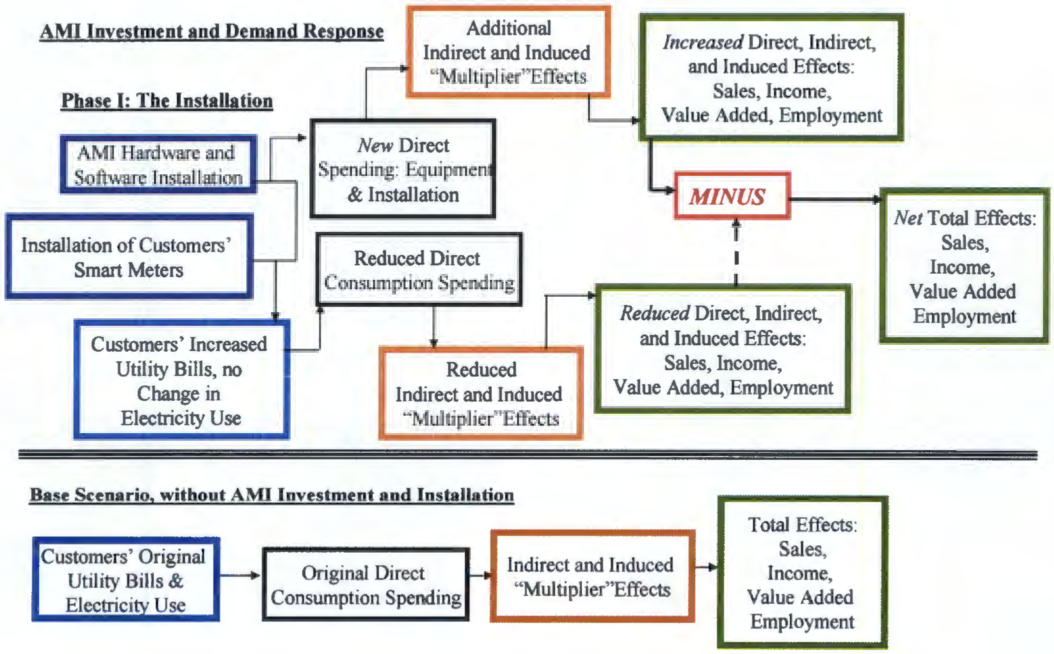

Figure B-1
Economic Impacts for AMI and Resulting Demand Reduction Programs, AMI Investment and Demand Response, Phase I, the Installation

For this reason, the net macroeconomic effects of the installation phase amount to the increased total effects from the increased direct spending by the utility. This is characterized by the top right side green box in the first Panel of Figure B.1. Since the effects on customer spending just cancel, the macroeconomic effects of this installation phase are independent of the share of the cost of the meters borne by the customers. However, it is true that the distribution of these macroeconomic effects is affected by the extent to which the cost of meters is borne by customers. And, if the cost of the installation and meters cannot be recovered from operational cost savings once the system is in place, then customers may see this reflected in future bills.

Phase II: Implementation of Demand Response Programs. This second phase is depicted in Figure B.2, where the top panel represents the changes in economic activity after the implementation of demand response programs facilitated through the Smart Metering investment. The bottom panel represents the Base Scenario without the investment or the demand response programs. The series of direct effects that leads to the macroeconomic impacts of this second phase are more complex than for Phase I, but the process by which the macroeconomic impacts come about can be clearly seen by following the arrows beginning with the boxes at the far right in the top panel of Figure B.2.

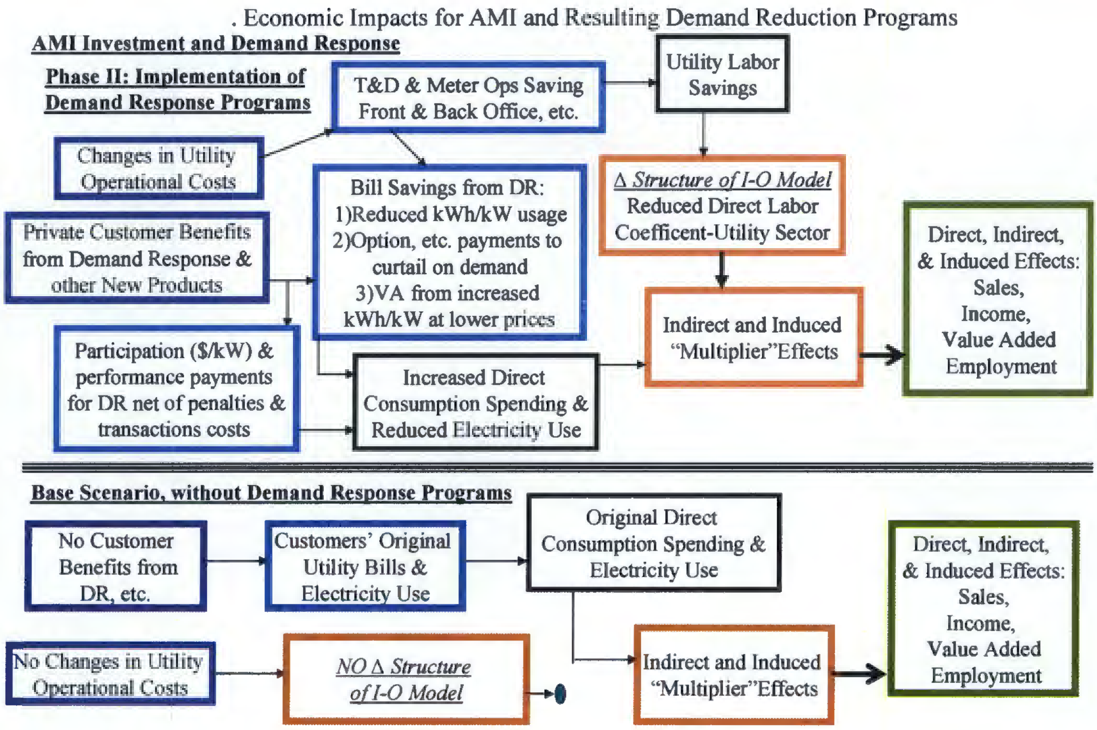

Figure B-2
Economic Impacts for AMI and Resulting Demand Reduction Programs, AMI Investment and Demand Response, Phase II, Implementation of Demand Response Programs

From the utility's standpoint, the direct implications at this phase are the realizations of reductions in operational costs. If the present value of these cost savings, over some appropriate period of time, were sufficient to cover the investment cost, then the financial implications from this Phase II exactly offset the costs in Phase I. It is anticipated that these operational cost savings may be due to such economies as a reduction in labor for reading meters, although there may be some increased demand for highly skilled labor to run and maintain the Smart Metering system. However, it is likely that there would be some overall labor savings. If these savings were indeed realized, then the *input structure* for the utility sector of the I-O model would have to be altered. An appropriate reduction in the labor input coefficient for the utility sector in the model would effectively mean that the industry would become slightly more capital intensive. Such a change would alter the I-O matrix. This, in turn, would affect the size of indirect and induced effects across all sectors resulting from direct changes in consumption spending and electricity purchases by customers, albeit the size of the effect in this case may be quite small.

Once the demand response programs are in place, the customers who participate in the programs are likely to see bill savings from reduced kWh/kW usage, option, and other payments to curtail on demand and value added from increased kWh/kW at lower prices. There may also be payment for participation and performance. Therefore, there will be both an increase in consumption purchases, as well as reduced electricity purchases. Obviously, the aggregate magnitude of these changes will depend on the number of customers that participate and the levels of participation. If the operational savings are sufficiently large, the utility may also pass along some of the savings to customers.

Regardless of the source, these bill savings and payments would be available to customers and would lead to increased direct consumption spending. As in Phase I, once these direct increases in consumption spending are allocated to the various sectors of the economy, the indirect and induced multiplier effects can be easily calculated. However, in contrast to Phase I, there is also some reduction in electricity purchases. Therefore, the combined total effects from these two types of changes on sales, income, value added, and employment must be calculated. From an analytical perspective, these total changes (in the green box in the first panel of Figure B.2) are calculated based on the revised I-O matrix that results from taking into account the reduced labor requirements by the utility.

In contrast to the case for Phase I, the Base Scenario without DR programs is based not only on the original direct customer consumption spending, but also on the original electricity purchases (lower panel, Figure B.2). The total economic effects are in the green box in the lower panel of Figure B.2. Therefore, unlike the situation in Phase I, the total effects of changes in purchasing patterns between the implementation phase and the base case will not will not be identically offsetting. The total economic impact of the changes in customer behavior under program implementation relative to the base case will depend on both: 1) the size of the increased consumption sending relative to the reduction in electricity purchases and 2) the differential total effects of a dollar of direct consumption spending versus a dollar spent on electricity. The relative size of the effect will also differ because, in the implementation phase, the effects will be evaluated based on a revised I-O matrix resulting from the reduced labor requirements by the utility in the implementation phase.

B.2 Summary

There is little doubt that there will be some macroeconomic effects from the investment in Smart Metering and the associated demand response programs that can be implemented as a result of the investment. However, without some initial estimates of the extent of customer participation and the level of participation, it is difficult to know the significance of such a macroeconomic assessment to an overall evaluation of the Smart Metering investment. Fortunately, the cost of conducting such a study, while not insignificant, would not be prohibitive. Nearly any economics consulting firm with access to state-of-the art I-O software, such as IMPLAN[81], and the data

[81] IMPLAN a software package and database for estimating local economic impacts, which is available from Minnesota IMPLAN Group, Inc. (Users Guide , IMPLAN Professional Version 2.0. Minnesota IMPLAN Group,

available from IMPLAN, Inc. needed to construct a state I-O table could conduct such a study. The only other additional data needed would be estimates of the investment and installation costs of the Smart Metering and the meters and estimates of DR participation and potential demand response and bill savings. Estimates of these quantities could be easily constructed from data available to the utility.

B.3 References

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Electricity Delivery
& Energy Reliability

American Recovery and
Reinvestment Act of 2009

Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies

Smart Grid Investment
Grant Program

November 2016

Table of Contents

Executive Summary

SGIG Consumer Behavior Studies (CBS)

Ten SGIG CBS utilities conducted 11 consumer behavior studies in accordance with research protocols established by DOE. These studies were intended to answer key questions facing decision makers on customer acceptance, retention, and response and address the cost-effectiveness of using time-based rates to achieve utility, customer, and societal objectives. Further information can be found on Smartgrid.gov.

Time-based rate programs[1], enabled by utility investments in advanced metering infrastructure (AMI), are increasingly being considered by utilities as tools to reduce peak demand and enable customers to better manage consumption and costs.

There are several customer systems that are relatively new to the marketplace and have the potential for improving the effectiveness of these programs, including in-home displays (IHDs), programmable communicating thermostats (PCTs), and web portals. Policy and decision makers are interested in more information about customer acceptance, retention, and response before moving forward with expanded deployments of AMI-enabled new rates and technologies.

Under the Smart Grid Investment Grant Program (SGIG), the U.S. Department of Energy (DOE) partnered with several electric utilities to conduct consumer behavior studies (CBS). The goals involved applying randomized and controlled experimental designs for estimating customer responses more precisely and credibly to advance understanding of time-based rates and customer systems, and provide new information for improving program designs, implementation strategies, and evaluations. The intent was to produce more robust and credible analysis of impacts, costs, benefits, and lessons learned and assist utility and regulatory decision makers in evaluating investment opportunities involving time-based rates.

To help achieve these goals, DOE developed technical guidelines to help the CBS utilities implement experimental designs that would provide more accurate estimates of customer acceptance, retention, and response. The guidelines were also intended to help the utilities identify the key drivers motivating customers to join programs and take actions to change their

[1] Time-based rates are electricity prices that vary with time and are intended to provide consumers with price signals that better reflect the time-varying costs of producing and delivering electricity.

electricity consumption behaviors. In addition, DOE provided a team of technical experts to help each utility focus their study efforts to better address long-term objectives.

There were ten CBS utilities conducting eleven studies. They comprised a generally representative group of utility types, sizes, and regions of the country. As shown in Table ES-1, each of the CBS utilities evaluated at least one of four types of time-based rate programs: critical peak pricing (CPP), critical peak rebates (CPR), time-of-use (TOU) pricing, and variable peak pricing (VPP).[2] In addition to rates, the CBS utilities also evaluated a variety of non-rate elements in their studies including information and automated control technologies as well as education. Lastly, all the CBS utilities employed an opt-in (voluntary) recruitment approach to their studies, while two augmented that effort with a separate opt-out approach (where customers are automatically defaulted on time-based rates).

Table ES-1. Scope of the Consumer Behavior Studies

	CEIC	DTE	GMP	LE	MMLD	MP	NVE	OG&E	SMUD	VEC
Rate Treatments										
CPP		●	●		●	●	●	●	●	
TOU		●		●		●	●	●	●	
VPP								●		●
CPR	●		●							
Non-Rate Treatments										
IHD	●	●	●					●	●	
PCT	●	●					●	●		
Education							●			
Recruitment Approaches										
Opt-In	●	●	●	●	●	●	●	●	●	●
Opt-Out				●					●	
Utility Abbreviations: Cleveland Electric Illuminating Company (CEIC), DTE Energy (DTE), Green Mountain Power (GMP), Lakeland Electric (LE), Marblehead Municipal Light Department (MMLD), Minnesota Power (MP), NV Energy (NVE), Oklahoma Gas and Electric (OG&E), Sacramento Municipal Utility District (SMUD), Vermont Electric Cooperative (VEC)										

[2] Technically, CPR is not a time-based rate; it is an incentive-based program. For presentation purposes it is classified with the other time-based rate programs.

All of the studies are complete. This report presents results from the interim and final evaluations for all 10 of the CBS utilities.[3]

Major Findings

There are five areas that results from the CBS utilities can be grouped into:

(1) Recruitment approaches – effects of opt-in and opt-out;
(2) Pricing versus rebates – effects of CPP and CPR;
(3) Customer information technologies – effects of IHDs;
(4) Customer control technologies – effects of PCTs; and
(5) Customer response to prices – effects of TOU.

Each is discussed in turn below and summarized in Table ES-2.

Recruitment Approaches – Effects of Opt-in and Opt-out

Social scientists have long recognized a behavioral phenomenon called the “default effect” or “status quo bias” – when facing choices that include default options, people are predisposed to remain on a pre-selected (i.e., default) option rather than choose alternative options. If the status quo bias holds true, then opt-out recruitment efforts for time-based rates would result in much higher enrollment levels than opt-in approaches. On the other hand, utilities and others generally expect customers to drop out at higher rates, and peak demand reductions to be lower, under default opt-out approaches than those recruited voluntarily under opt-in.

Results from the CBS utilities show that under opt-out recruitment approaches enrollment rates were indeed much higher (92% vs. 15%) and peak demand reductions were generally lower (6% vs. 12% for TOU and 13% vs. 23% for CPP) than under voluntary enrollment methods. However, retention rates were about the same for both (90% vs. 87%). From these results, one would expect larger aggregate peak demand reductions from comparably sized populations of customers solicited for TOU or CPP using opt-out versus opt-in approaches. Also, the overall cost-benefit advantages are expected to be greater for opt-out approaches than opt-in approaches since efforts to default customers on rates require less effort than enrolling

[3] All of the CBS utilities’ evaluation reports can be accessed from the Consumer Behavior Study section of smartgrid.gov. In addition, a number of other CBS related documents relating to guidance provided to the CBS utilities as well as additional evaluation results can be found.

volunteers. We observed benefit-cost ratios greater than 2.0 for opt-out and between 0.7 and 2.0 for opt-in, depending on rate and technology combination.[4]

Prices versus Rebates – Effects of CPP and CPR

The behavioral science theory of loss aversion states that when people are presented with a choice that involves the potential of either avoiding a loss or acquiring a gain, the strong preference is to avoid the loss rather than to acquire the gain. As a result, one would expect that customers would be more likely to enroll in and remain on CPR than CPP. The perceived risk of receiving higher bills from under performance during critical events under CPP is greater than under CPR, and this could be a motivating factor that decreases enrollment and retention for CPP. However, once customers are on a rate, because the risk of potential loss from CPP is more salient than the potential gain from CPR, customers are expected to respond more to CPP.

Results from the CBS utilities support this theory as retention rates were higher for CPR (89%) than for CPP (80%) and demand reductions were generally higher for CPP (21%) than for CPR (11%), whereas the variability in average demand reductions across events was less for CPP than it was for CPR. However, when PCTs were available as an automated control strategy, the differences in average peak demand reductions between CPP and CPR were largely eliminated. This suggests that regardless of the financial incentive to respond (i.e., acquiring a gain via a rebate or avoiding a loss via pricing), PCTs can be an effective tool to mitigate a customer's loss aversion by allowing them to automate their response during the critical peak events.

[4] The SMUD benefit-cost results are based on a ten year net present value analysis. The benefits were based on the deferral value of capacity additions and avoided wholesale energy costs due to reduced loads during high cost periods or shifting usage from higher to lower cost periods. The costs were based on marketing, program administration and technology expenses. See Section 10.1 "SmartPricing Options – Final Evaluation" SMUD, September 5, 2014.

Table ES-2. Summary of Major Findings	
Area	**Major Findings – Demand Reductions & Enrollment/Retention Rates**
Recruitment Approaches – Opt-in & Opt-out	• Opt-out enrollment rates were about 3.5 times higher than they were for opt-in (93% vs. 15%). • Retention rates for opt-out recruitment approaches (85.5% in year 1 and 88.5% in year 2) were about the same as they were for opt-in (89.7% in year 1 and 91.0% in year 2). • Peak period demand reductions for SMUD's opt-in TOU customers were about twice (13% in year 1 and 11% in year 2) as large as they were for opt-out customers (6% in year 1 and year 2). • Peak period demand reductions for SMUD's opt-in CPP customers were about 50% higher (24% in year 1 and 22% in year 2) than they were for opt-out customers (12% in year 1 and 14% in year 2). • SMUD's opt-out offers were more cost-effective for the utility than their opt-in offers in all cases. • Roughly two-thirds of those who were defaulted onto SMUD's TOU rates were expected to see bill impacts of +/- $20 for the entire 4 summer months the rates were in effect. • Based on survey responses, a majority of those defaulted onto SMUD's TOU rate were satisfied with the rate, regardless of the level of bill savings achieved, but those who saw the largest bill increases were generally less interested in continuing with the rate after the study ended.
Pricing Versus Rebates – CPP & CPR	• While opt-in enrollment rates for GMP were about the same for CPP (34%) and CPR (35%), retention rates were somewhat lower for CPP (80%) than they were for CPR (89%). • Average peak demand reductions for CPP (20%) were about 3.5 higher than they were for CPR (6%), but when automated controls (PCTs) were provided, they were about 30% larger (35% for CPP and 26% for CPR).
Customer Information Technologies - IHDs	• Enrollment and retention rates were generally unaffected by offers of IHDs. • SMUD's opt-in CPP customers with IHDs (26% in year 1 and 24% in year 2) had somewhat higher peak demand reductions than those without IHDs (22% in year 1 and 21% in year 2), but these differences can be explained by pre-treatment differences between the two groups. • SMUD's opt-in TOU customers with IHDs (13% in year 1 and 11% in year 2) had somewhat higher peak demand reductions than those without IHDs (10% in year 1 and 9% in year 2), but these differences can be explained by pre-treatment differences between the two groups. • SMUD's offerings without IHDs were more cost-effective for the utility in all cases than those with IHDs.
Customer Control Technologies - PCTs	• Enrollment and retention rates were generally unaffected by offers of PCTs. • Peak demand reductions are generally higher for CPP and CPR customer with PCTs (22% to 45%) than they were for customers without PCTs (-1% to 40%). • OG&E rate offers with PCTs were more cost-effective for the utility than those without PCTs.
Customer Response to Price - TOU	• Peak period demand reductions were far less, on average, for the lowest peak to off-peak price ratios (6% for treatments with a peak to off-peak price ratio less than 2:1) than for the highest price ratios (18% for treatments with a peak to off-peak price ratio greater than 4:1). • When a CPP/CPR was overlaid on the TOU rate, the average event peak demand reduction rose to 27% when averaged over all of the treatments • When PCTs were available, the differences in average peak period demand reductions were only affected at peak to off-peak price ratios in excess of 2:1 (21% vs. 10% for price ratios between 2:1 and 3:1 and 23% vs. 15% for price ratios in excess of 4:1).

Customer Information Technologies – Effects of IHDs

Customer information technologies such as IHDs and web portals provide ways of raising customer awareness about usage levels, consumption patterns, electricity prices, and costs. By raising awareness about prices and usage patterns, utilities create opportunities for customers to better understand how usage affects their bills. With this information, utilities expect customers will have better capabilities for understanding and responding to time-based rates. When IHDs are offered by utilities to customers for free (which is frequently done to bolster participation rates) implementation costs increase, so it is important to understand if the benefits outweigh the costs of the devices.

Results from the CBS utilities show that free IHD offers did not make a substantial difference for enrollment and retention rates (+/- 1-4 percentage points). Although SMUD's peak demand reduction estimates were larger with IHDs (2-3 percentage points), this result can be attributed to pre-treatment differences between the two groups so there was not a measured IHD effect on reductions of peak demand. As a result, because the cost of providing IHDs is non-negligible, the benefit-cost ratios of rate offerings were lower when they included offers of free IHDs relative to when they were absent (0.74 vs. 1.19 for TOU and 1.30 vs. 2.05 for CPP). In addition, many of the CBS utilities reported significant challenges with this relatively new technology. Problems included very low customer connectivity rates (e.g., less than 20% were connected all the time while between 42% and 65% were never connected at all), getting the IHDs to function properly (e.g., binding to the meter to receive data) and in one case the manufacturer decided to halt production and stop support in the middle of the study.

Customer Control Technologies – Effects of PCTs

Conceptually, automated control technologies such as PCTs lower the transactional effects associated with responding to prices and critical peak events by making it easier for customers to alter their electricity consumption at specified times. As with IHDs, utility offers of free PCTs cause implementation costs to increase, so it is important to understand if the value of the additional demand reductions outweighs the costs of the devices.

Although the studies were not designed and implemented in such a way as to measure the effect of PCTs on enrollment, results from the CBS utilities show that free PCT offers did not make a major difference for retention (91% with or without PCTs). However, peak demand reductions were substantially higher when a PCT was present (22-45% reduction with a PCT vs. -1 to 40% without one) while the variability of those reductions was less, which should increase the value of such demand reductions. Unlike with IHDs, benefit-cost ratios for PCT offers were favorable (i.e., greater than 1.0). In response, one utility (OG&E) decided to roll-out a time-based rate with an offer of a free PCT to its entire residential customer class with a recruitment goal of 120,000 customers within three years.

Customer Response to Prices – Effects of TOU

Economic theory suggests that people are generally willing to buy larger quantities of a good as its price goes down. Conversely, as the price increases, people are expected to buy less of that same good. This basic relationship can be used to explain what the CBS utilities expected to happen when they introduced a TOU rate into their study: electricity consumption would be reduced in the peak period when the peak period price of electricity was raised relative to the price of electricity in the off-peak period.

The estimated demand reductions during the peak period from customers exposed to a TOU rate ranged from a low of -1% (i.e., load increased for the average customer in this TOU treatment by 1%) to a high of 29%, with an average of 15%. On average, customers responded to a greater extent (i.e., reduced their peak demand to a greater extent) when exposed to higher rather than lower price ratios. Results indicate that customers reduced demand during the peak period by 6%, on average, when experiencing a peak to off-peak price ratio less than 2:1 compared to 18% when experiencing a price ratio greater than 4:1. However, when PCTs were available as an automated control strategy, the variability of peak period demand reductions was significantly reduced and greater reductions were observed for price ratios in excess of 2:1 (21% vs. 10% for price ratios between 2:1 and 3:1 and 23% vs. 15% for price ratios in excess of 4:1). This suggests that PCTs can be an effective tool in augmenting peak period demand reductions, but only if the price ratio is high enough. When CPP/CPR was overlaid on the TOU rate, the average event peak demand reduction was 27% when averaged over all of the treatments. However, when PCTs were available, the average event peak demand reduction was 34% vs. 24% when such automated control technology was not available.

Concluding Remarks

Rigorous experimental methods were applied in these consumer behavior studies with the belief that more credible and precise load impact estimates would help resolve some of the outstanding issues hindering broader industry adoption of time-based rates for residential customers. Since none of the CBS utilities had any experience with such experimental methods, each CBS utility was provided with a small team of industry experts who provided technical assistance in the design, implementation and evaluation of each study. Besides direct engagement with each CBS utility, these Technical Advisory Groups (TAGs) also produced a library of guidance documents for the CBS utilities (publicly available on smartgrid.gov) on such diverse topics as study plan documentation, experimental design, rate and non-rate treatments, and evaluation techniques. With the help of these TAGs and the reference material they produced, many of the concerns initially raised about the application of experimental methods (e.g., that withholding or deferring exposure to the rate after a customer had agreed to participate in the study would create customer relations problems) did not materialize. In addition, TAGs helped the utilities more narrowly focus their studies on a core set of objectives that would more directly inform the utilities on suitable pricing strategies. As such, the consumer behavior study program produced results that significantly contributed to our understanding of several critical issues, as described above.

Both utilities and participating customers learned a tremendous amount about themselves and their capabilities through these studies. Although not an explicit objective of the consumer behavior studies, successful recruitment into the pricing studies hinged on the ability of the CBS utilities to effectively engage customers – many of whom had very limited experience in this arena. As such, several CBS utilities recognized the importance of performing market research during the study design phase to ensure marketing material was as effective as possible to engage customers as participants in the studies. The most successful CBS utilities continued that engagement not just during recruitment but throughout the study period itself, which included the creation of a plethora of different materials using a number of different mediums (e.g., monthly newsletters, social media campaigns of tips and tricks) that constantly sought to keep customers engaged in the study. Such efforts seemed to be quite successful, as the vast majority of customers who started the studies also completed them, expressed a high level of satisfaction in their experiences with these new rates and to a lesser extent with the new technologies, and continued taking service under the rate after the study ended, provided such opportunities were available.

The results of the consumer behavior study effort has helped the participating utilities and others to advance the application of time-based rates. Three of the ten CBS utilities allowed participants to continue taking service under the rates after their study was completed. Four of the ten CBS utilities chose to extend an offer of the rates tested in their study to the broader population of residential customers. Specifically, OG&E has enrolled approximately 116,000 of their residential customers (representing approximately 18% of their residential population) on their SmartHours program, 100,000 (86%) of which are taking service on the variable peak pricing rate tested in its CBS, and are achieving 147 MW of peak demand reduction. This voluntary SmartHours program includes the offer of a free PCT, which 90% of customers have taken. SMUD chose to make the TOU rate it tested the default for all of its residential customers, starting in 2018. More broadly, the California Public Utility Commission ordered all of the state's investor-owned utilities to make TOU the default for residential customers, citing heavily the very positive results SMUD achieved as grounds for this decision. DOE hopes the experiences and results from the CBS effort will help the industry to effectively consider the application of time-based rates for residential customers.

1. Introduction

Time-based rates, enabled by utility investments in advanced metering infrastructure (AMI), are increasingly being considered by utilities and policy makers as tools to augment incentive-based programs for reducing peak demand and enabling customers to better manage consumption and costs. In addition, there are several customer systems that are relatively new to the marketplace that have potential for improving the effectiveness of these programs, including in-home displays (IHDs), programmable communicating thermostats (PCTs), web portals, and a host of new and novel software and data applications.[5]

The electric power industry is interested in more information about residential customer preferences for and responses to time-based rates and incentive-based programs as utilities and other stakeholders propose plans for expanded deployments. Under the U.S. Department of Energy's (DOE) Smart Grid Investment Grant Program (SGIG), several utilities took part in a Consumer Behavior Study (CBS) effort in order to develop information on preferences and responses to time-based rates and incentive-based programs, including impacts, benefits, and lessons-learned that could inform utilities' and policy makers' decisions about the design and implementation of new rate and technology offerings.

1.1 Background about Time-Based Rates and Advanced Metering Infrastructure

From the early days of the electric power industry, utilities, policy makers, and academics have shown interest in time-based rates for electricity.[6] When designed correctly, such rates allow the prices that customers pay to use electricity to correspond more closely to the actual costs of producing or procuring it. For most utilities, the cost of providing electricity changes over a variety of different time dimensions: minute, hour, day, month, and season. In general, as demand for electricity increases, higher-cost power plants must be brought online to accommodate the additional demand. Furthermore, the variable nature of certain types of renewable generation technologies likewise can cause power costs to fluctuate. Figure 1 shows how different types of time-based rates can reflect to varying degrees the marginal costs of producing electricity. Although not shown in the figure, real-time pricing (RTP), in its ideal form, can perfectly reflect these marginal costs. The alternative rates shown in the figure, critical peak pricing (CPP), variable peak pricing

[5] For example, the Green Button initiative which provides a standard protocol for customers to gain access to their interval meter data.

[6] Hausman, W. J. and J. L. Neufeld (1984). "Time-of-Day Pricing in the U.S. Electric Power Industry at the Turn of the Century." The Rand Journal of Economics 15(1): 116-126.

(VPP), and time-of-use (TOU), all seek to reflect at a more aggregate level the average of the marginal cost of producing electricity during various periods of time.

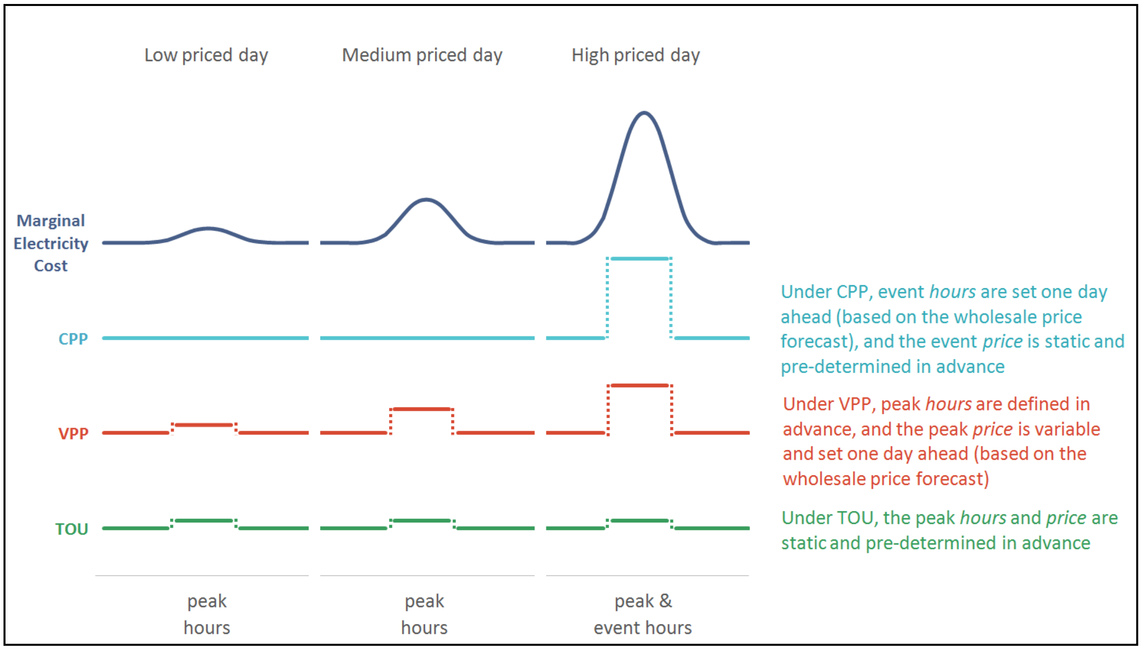

Figure 1. An Illustration of Several Time-Based Rate Designs.

Furthermore, a myriad of financial benefits inure to utilities and their ratepayers when customers take service under and respond to time-based rates. The value associated with lowering peak demands is often at its highest when reductions in consumption coincide with times that the local or regional power system is experiencing its highest level of demand (i.e., the coincident system peak demand). Such reductions in electricity demand at these times can lead to future deferrals of new investments or upgrades in electric generation, distribution and possibly transmission facilities, and/or avoidance of higher prices or demand charges from wholesale power suppliers. These results can lead to reductions in the utility's overall cost of service, which can benefit all customers when the reductions are passed on through retail rates.

In 1978, the U.S. Congress saw the value of trying to move the electric power industry towards more time-based pricing and passed The Public Utility Regulatory Policies Act[7] (PURPA). This legislation contained standards calling for states to consider adoption of TOU rates to better reflect the costs of service by charging prices that encouraged customers to shift consumption from more expensive peak to less expensive off-peak periods. In response to PURPA, many states implemented TOU rates

[7] Subtitle B asked state regulatory authorities and non-regulated electric utilities to determine whether or not it is appropriate to implement TOU rates and other ratemaking policies.

on a pilot basis to evaluate their cost-effectiveness. During the early 1980s, evaluations of those pilot programs by the Federal Energy Administration (a DOE predecessor) found that customers responded to TOU rates and successfully shifted electricity use from higher to lower cost times of day.[8] However, the costs of new meters capable of measuring consumption by time-of-day presented a barrier at that time to cost-effective implementation of TOU rates on a larger scale.

In spite of this, interest by state policy and decision makers in deployments of time-based rate programs has remained. In fact, more than 100 studies have been published that assess how customers change their consumption patterns in response to time-based rate programs, including assessments of how customer responses are helped or hindered by access to usage information from web portals and in-home displays, or by use of control technologies that automate electricity-consuming devices such as programmable communicating thermostats.[9] Results from these studies vary widely[10] and many policy and decision makers continue to ask for more detailed and more precise information about key policy questions, including:

- Does the enrollment condition (i.e., opt-in, opt-out) affect customer acceptance, retention and/or response to a time-based rate?
- Does the existence of control and/or automation technology (e.g., programmable communicating thermostat) affect customer acceptance, retention and/or response to a time-based rate?
- Does the existence of information technology (e.g., in-home display) affect customer acceptance, retention and/or response to a time-based rate?
- Do customer demographics (e.g., low-income, high usage, elderly households, college educated) play a role in customer acceptance, retention, and/or respond to a time-based rate?
- What is the persistence of participation and response over time to a time-based rate?
- What role does bill protection and/or bill guarantees have on customer acceptance, retention and/or response to a time-based rate?

Over the past 15 years, the costs of interval meters and the communications networks to connect the meters with utilities and back-office systems (i.e., advanced metering infrastructure, or AMI)

[8] Faruqui, A. and J. R. Malko (1983). "The residential demand for electricity by time-of-use: A survey of twelve experiments with peak load pricing." Energy 8(10): 781-795.

[9] Faruqui, A. and S. Sergici (2010). "Household Response to Dynamic Pricing of Electricity-A Survey of the Empirical Evidence." Social Sciences Research Network.

[10] EPRI (2012). Understanding Electric Utility Customers: What we know and what we need to know. EPRI. Palo Alto, CA.

have decreased. Recent implementation of AMI allows electricity consumption data to be captured, stored and reported at 5 to 60-minute intervals and provides opportunities for utilities and policymakers to reconsider the merits of widespread deployment of time-based rates. The benefits which may result from the application of time-based rates often times helps to justify the business case for investments in AMI. In addition to enabling time-based rates, AMI also provides new opportunities for utilities to lower costs by automating meter reading, service connections and disconnections, and tamper and theft detection. AMI can also lower electric distribution costs through improvements in outage management and voltage controls.[11]

At present, many regulators, policy makers, and other stakeholders are seeking more definitive answers to key policy questions as well as more accurate estimates of value-streams before supporting AMI investments and expanded implementation of time-based rates for residential and small commercial customers.

1.2 Overview of DOE's Consumer Behavior Studies (CBS) Program

In 2009, Congress saw an opportunity to advance the electricity industry's investment in the US power system's infrastructure by including the Smart Grid Investment Grant (SGIG) as part of the American Recovery and Reinvestment Act (Recovery Act). To date, DOE and the electricity industry have jointly invested over $7.9 billion in 99 cost-shared SGIG projects that seek to modernize the electric grid, strengthen cybersecurity, improve interoperability, and collect an unprecedented level of data on smart grid and customer operations enabled by these investments. The SGIG program included more than 60 projects that involved AMI deployments with the aim of improving operational efficiencies, lowering costs, improving customer services, and enabling expanded implementation of time-based rate programs.[12]

In selecting project applications for SGIG awards, DOE was interested in working closely with a subset of utilities willing to conduct comprehensive consumer behavior studies that applied randomized and controlled experimental designs. DOE's intent for the studies was to encourage the utilities to produce robust statistical results on the impacts of time-based rates, customer information systems, and customer automated control systems on peak demand, electricity consumption, and customer bills. The intent was to produce more robust and credible analysis of

[11] DOE's Recovery Act smart grid programs have produced a number of reports and case studies documenting the impacts and financial benefits of AMI for these purposes. These can be downloaded from www.smartgrid.gov.

[12] SGIG has helped to deploy more than 16.3 million new smart meters, which represents about 32% of the 50 million smart meters that have been installed nationwide as of 2015.

impacts, costs, benefits, and lessons learned and assist utility and regulatory decision makers in evaluating investment opportunities involving time-based rates. Of the SGIG projects investing in AMI and implementing time-based rate programs, there were ten utilities that were interested in working with DOE to participate in the CBS program.

The ten CBS utilities set out to evaluate a variety of different time-based rate programs and customer systems. Concerning the former, the CBS utilities planned to study TOU, CPP, VPP, and critical peak rebates (CPR).[13] Many also planned to include some form of customer information system (e.g., IHDs) and/or customer automated control system (e.g., PCTs). Several CBS utilities evaluated multiple combinations of rates and customer systems, based on the specific objectives of their SGIG projects and consumer behavior studies. For example, one utility evaluated treatment groups with a CPP rate layered on top of a flat rate, in combination with and without IHDs. Another evaluated VPP as well as CPP layered on top of a TOU rate in combination with and without PCTs.

1.3 DOE's Technical Approach to the CBS Program

DOE's goal for all of the consumer behavior studies was for them to produce load impact results that achieve internal and ideally external validity.[14] To help ensure that this goal was met, DOE published ten guidance documents for the CBS utilities. The guidelines were intended to help the utilities better understand DOE's expectations of their studies to achieve these goals, including their design, implementation, and evaluation activities.

Specifically, several of the DOE guidance documents addressed how to appropriately apply experimental methods such as randomized controlled trials and randomized encouragement designs to more precisely estimate the impact of time-based rates on electricity usage patterns, and identify the key drivers that motivated changes in behavior.[15] The guidance documents identified

[13] Technically, CPR is not a time-based rate; it is an incentive-based program. However, for simplicity of presentation, it is classified with the other event-driven time-based rate programs.

[14] Internal validity is the ability to confidently identify the observed effect of treatments, and determine unbiased estimates of that effect. External validity is the ability to confidently extrapolate study findings to the larger population from which the sample was drawn.

[15] The experimental designs were intended to ensure that measured outcomes could be determined to have been caused by the program's rate and non-rate treatments, and not random or exogenous factors such as the local economic conditions, weather or even customer preferences for participating in a study. Most of the studies decided to use a *Randomized Controlled Trial* experimental design, which is a research strategy involving customers that volunteer to be exposed to a particular treatment and are then randomly assigned to either a treatment or a control group. A few studies chose to use a *Randomized Encouragement Design*, which is a research strategy involving two groups of customers selected from the same population at random, where one is offered a treatment while the other is not. Not all customers offered the treatment are expected to take it, but for analysis purposes, all those who are offered the

key statistical issues such as the desired level of customer participation, which was critical for ensuring that sample sizes for treatment and control groups were large enough for estimates of customer response to have the desired level of accuracy and precision. Without sufficient numbers of customers in control and treatment groups, it would be difficult to determine whether or not differences in the consumption of electricity were due to exposure to the treatment or random factors (i.e., internal validity).

To make best use of the guidance documents, DOE assigned a Technical Advisory Group (TAG) of industry experts to each CBS utility to provide technical assistance. The TAGs helped customize the application of the guidance documents as each of the utility studies was different and had their own goals and objectives, starting points, levels of effort, and regulatory and stakeholder interests. These latter factors, in conjunction with the DOE guidance documents, determined how each utility study was designed and implemented. For example, several utilities had prior experience with time-based rates and used the studies to evaluate needs for larger-scale roll-outs. Others had little or no experience and used the studies to learn about customer preferences and assess the relative merits of alternative rates and technologies.

Each CBS utility was required to submit a comprehensive and proprietary Consumer Behavior Study Plan (CBSP) that was reviewed by the TAG and approved by DOE. In its CBSP, each utility documented the proposed study elements, including the objectives, research hypotheses, sample frames, randomization methods, recruitment and enrollment approaches, and experimental designs. The CBSP also provided details surrounding the implementation effort, including the schedule for regulatory approval and recruitment efforts, methods for achieving and maintaining required sample sizes, and methods for data collection and analysis.[16]

Each CBS utility was also required to comprehensively evaluate their own study and document the results, along with a description of the methods employed to produce them, in a series of evaluation reports that were reviewed by the TAG, approved by DOE, and posted on Smartgrid.gov. Each utility was expected to file an interim evaluation report after the first year of the study and a final evaluation report at the end of the study.

treatment are considered to be in the treatment group. For more information, see "Quantifying the Impacts of Time-based Rates, Enabling Technology, and Other Treatments in Consumer Behavior Studies: Protocols and Guidelines" July 2013, Lawrence Berkeley National Laboratory.

[16] In several cases, utilities encountered problems during implementation (e.g., insufficient numbers of customers in certain treatment groups) that required the study's initial design as described in the CBSP to be altered to maintain a high probability of achieving as many of the study's original objectives as possible. For several utilities this meant reductions in the number of treatment groups included in the studies.

1.4 Reporting

In addition to the CBS utilities' evaluation reports, DOE funded research on a variety of topics related to this CBS effort utilizing independent analysis of data collected by the CBS utilities throughout their studies.[17] Some of these reports are for a general audience and can be found on DOE's smart grid website (smartgrid.gov). A number of other reports, which are considerably more technical in nature, can be found at Lawrence Berkeley National Laboratory's (LBNL) website (emp.lbl.gov). Finally, a small subset are highly technical and will be published in peer-reviewed academic journals.

Table 1 lists the title of each report that has already been published as a DOE report (smartgrid.gov) or an LBNL report (emp.lbl.gov) as well as when it was published.

Table 1. Prior SGIG CBS Reports

Titles	Publication Location	Publication Dates
Smart Grid Investment Grant Consumer Behavior Study Analysis: Summary of Utility Studies	Smartgrid.gov	June 2013
Residential Customer Enrollment in Time-based Rate and Enabling Technology Programs	Smartgrid.gov	June 2013
Analysis of Customer Enrollment Patterns in Time-Based Rate Programs – Initial Results from the SGIG Consumer Behavior Studies	Smartgrid.gov	July 2013
Experiences from the Consumer Behavior Studies on Engaging Customers	Smartgrid.gov	September 2014
Time-of-Use as a Default Rate for Residential Customers: Issues and Insights	Emp.lbl.gov	June 2016
Experiences of Vulnerable Residential Customer Subpopulations with Critical Peak Pricing	Emp.lbl.gov	September 2016

Those research activities that DOE continues to fund, which include an analysis of the data collected by the CBS utilities through their consumer behavior studies, will include the following topics, which will be reported separately as LBNL reports and/or as peer-reviewed journal articles:

- **Go for the Silver? Comparing Quasi-Experimental Methods to the Gold Standard**

[17] This rich dataset includes: study assignment, participation and retention data; interval meter data; survey data; customer systems data; and other data collected during the course of each study.

Randomized controlled trials (RCTs) are widely viewed as the "gold standard" for evaluating the effectiveness of an intervention. However, analysis of the effect of energy pricing has largely been conducted through quasi-experimental methodologies. Analyzing interval meter data from a subset of the CBS utilities, the true estimates obtained through the RCT will be compared with those derived from an application of quasi-experimental designs as well as from a regression discontinuity design. The goal will be to identify what might be causing any observed bias when non-RCT methods are used in this setting.

- **Understanding What Drives the Bias in Baseline Methods for Evaluating Demand Reduction**
  This research expands upon the comparison of impact estimates from experimental and quasi-experimental designs in order to delve deeper into an examination of the bias of the current best performing baseline methods in an attempt to identify the cause and implications of this bias. By analyzing interval meter data from the Sacramento Municipal Utility District's consumer behavior study, the cause of the bias can hopefully be identified: spillover, in which customers reduce demand not only during the hours that the program is designed to target, but also during other hours. The analysis will also attempt to understand the conditions under which the bias is bigger or smaller (e.g., temperature of event days; temperature of the days preceding the event; length of time between events; length of time customers have been enrolled in the CPP rate).

1.5 Data Sources

This report summarizes the major findings of DOE's SGIG-funded consumer behavior studies of time-based rates. A key source of information for the results reported herein comes from the interim and final evaluation reports that were submitted by the CBS utilities to DOE. However, not all of the utilities designed their studies to produce results that were perfectly comparable, reported information in the same way, or included metrics using the same analytical methods. When possible, this report presents aggregated results using comparable data from two or more of the utilities. Results from individual utilities are also presented where appropriate to highlight key findings. In general, the findings in this report address the following topics[18]:

[18] An assessment of bill impacts which incorporate the effects of customer response to time-based rates was not undertaken. Event driven rates are designed to be revenue neutral based on the dispatch of a specific number of events where a dramatically higher rate is in effect. If not all of those events are actually called during the study relative to the number used in designing the rate, then participating customers are highly likely to experience bill savings. This is not necessary reflective of their efforts to reduce or shift load during events, but rather an artifact of the rate design. As such, a reporting of bill impacts out of the consumer behavior studies could be misleading, since most of the studies

- The choices made by participating customers to enroll, accept, and remain involved in time-based rates. This includes information about the effects on customer choices from different forms of recruitment (i.e. opt-in versus opt-out), customer systems (i.e., IHDs and PCTs), and time-based rate offerings (i.e., CPP, CPR).
- The customer responses in terms of customer electricity demand reductions that stem from the application of different recruitment methods, customer systems, and time-based rates.
- The cost-effectiveness of the rates, programs, and customer-systems for the utility.[19]

The contents of any prior DOE-funded independent analysis of the data generated by the CBS utilities also serves as reference material for the results reported herein and is noted accordingly.

who included some form of CPP (which was a majority of the studies as will be discussed in Chapter 2) did not call all of the events for which the rate was designed for.

[19] However, there was limited information in the evaluation reports on this topic.

2. Scope and Status

Because each utility had its own unique study objectives, it is important to understand some of the details about each of the studies to more fully frame the results, and their implications. Each of the study summaries presented below contains a description of the overall SGIG project and to the study itself.[20] The Appendix contains additional information on the rates offered by the CBS utilities.

2.1 Types of Rate and Non-Rate Treatments in DOE's CBS Program

The CBS utilities evaluated a variety of time-based rates for their impact on customer acceptance, retention and response including ones that are driven by critical peak events and ones that are not. The primary objective of event-driven rates is to achieve reductions in peak (i.e., maximum) demand. Typically, utilities determine the need for critical peak events based on short-term system conditions, high forecasted wholesale market prices, or both. Participating customers receive notification of the events either on the day before or early on the critical peak event day.

The CBS utilities evaluated two primary types of event-driven rate programs: CPP and CPR. CPP designs involve increases in the price of electricity consumed during pre-determined hours (event period) on event days.[21] This higher price is overlaid onto the existing retail rate. CPR is similar to CPP except that customers are paid an incentive to reduce demand during the event period, relative to a baseline.[22]

The primary objective of non-event driven rate designs involves customers altering their consumption patterns more broadly, for example by shifting electricity consumption away from one part of the day to another. TOU rates are one of the most widely implemented types of non-event driven time-based rates and involve designs that charge customers for electricity usage based on the block of time it is consumed. Typically, this involves higher prices during a pre-determined set of

[20] Further details on the scopes of the studies can be found in "Smart Grid Investment Grant Consumer Behavior Study Analysis: Summary of Utility Studies" June 2013, Lawrence Berkeley National Laboratory.

[21] Most retail electric rates are designed to collect the same amount of revenue annually from the average customer in a class. Since CPP is designed to impose higher prices during a set number of critical peak events each year, the retail electric rate is lower on non-event days than the existing traditional utility tariff to offset the higher revenue collected during these events. This means customers have a risk for much higher bills when critical events are called (due to the higher price during events), but this would be offset by slightly lower bills the rest of the year.

[22] CPR is usually designed to overlay the incentive payment on the existing traditional utility tariff that is not changed. As such, the CPR incentive payments are typically drawn from levying slightly higher retail electric rates on all customers, not just those taking service under CPR. Because the rate increases associated with the incentive payments are spread across all customers in the class, they can be quite small on a per customer basis and are rarely noticed.

peak hours and lower prices during off-peak hours. TOU price schedules are fixed and pre-defined based on season, day of week, and time of day.

VPP, a hybrid of CPP and TOU, involves designs in which customers are charged based on the block of time electricity is consumed, but the price schedule differs based on existing power system conditions and/or wholesale market prices for that day. VPP rates are intended to encourage customers to broadly shift consumption away from peak periods, but to also accomplish greater peak demand reductions as needed when system conditions or market prices warrant.

In addition to rates, the CBS utilities also evaluated the role of customer systems including information and automated control technologies on customer acceptance, retention and response. Customer systems are thought to increase interest in acceptance of time-based rates, heighten interest in remaining on such rates, more easily respond to such rates and more generally enhance the ability of customers to manage electricity costs. Information technologies, like IHDs, more conveniently provide customers cost and energy use information, and control technologies, like PCTs, provide capabilities for customers to automate their responses to time-based rates.

The CBS utilities also evaluated different approaches to recruiting customers to participate and take service under the various time-based rates included in the studies. Many CBS utilities used an opt-in approach that sought volunteers to participate in the study. In a few cases, CBS utilities included an opt-out approach whereby customers were told they would be participating in the study unless they took action and declined.

Table 2 shows the rate and technology offerings being evaluated by the CBS utilities. The subsections that follow provide information about the scope and status of the ten utility studies.

Table 2. Scope of the Consumer Behavior Studies										
	CEIC	DTE	GMP	LE	MMLD	MP	NVE	OG&E	SMUD	VEC
Rate Treatments										
CPP		●	●		●	●	●	●	●	
TOU Pricing		●		●		●	●	●	●	
VPP								●		●
CPR	●		●							
Non-Rate Treatments										
IHD	●	●	●					●	●	
PCT	●	●					●	●		
Education							●			
Recruitment Approaches										
Opt-In	●	●	●	●	●	●	●	●	●	●
Opt-Out				●					●	
Utility Abbreviations: Cleveland Electric Illuminating Company (CEIC), DTE Energy (DTE), Green Mountain Power (GMP), Lakeland Electric (LE), Marblehead Municipal Light Department (MMLD), Minnesota Power (MP), NV Energy (NVE), Oklahoma Gas and Electric (OG&E), Sacramento Municipal Utility District (SMUD), Vermont Electric Cooperative (VEC)										

2.2 Cleveland Electric Illuminating Company (CEIC)

Overview. CEIC is part of FirstEnergy Services Corporation's SGIG Project which had a total budget of about $114 million (DOE's share of about $57 million) and included installation of about 34,000 smart meters, associated communications networks, and distribution automation equipment on about sixty feeders. CEIC's consumer behavior study's initial design involved about 5,000 residential customers and focused on evaluating the timing and magnitude of changes in customer peak demand and energy usage patterns in response to CPR and use of IHDs and PCTs.

Treatments. Rate treatments included the implementation of a CPR that provides a payment to customers for reducing electric demand during declared critical peak events, while the price charged by CEIC for electricity consumed at other times stays at existing flat rates. Customers received day-ahead notification of critical peak events and could receive such notification up to 15 times per year. Technology treatments included IHDs and PCTs. The PCTs involved two treatment methods:

customer control and utility control. Because several treatment groups fell short of recruitment goals, CEIC chose to focus on a smaller number of treatments to obtain more precise impact estimates. The treatments involved a flat rate with CPR that included a $0.40 per kilowatt hour rebate and either (1) a four hour event duration that could be paired with an IHD or customer-controlled PCT, and (2) a four- or six-hour event duration that could be paired with a utility-controlled PCT.

Design. The study's experimental design involved a randomized encouragement design where customers were randomly assigned to either be offered a treatment or not offered a treatment. Data from customers who were offered a specific treatment but declined the offer were included in the study with data from the customers who were randomly assigned and not offered a treatment.

Status. CEIC completed its consumer behavior study. The recruitment effort fell short of its goals and so several of the experimental cells had to be dropped to maintain, to the degree possible, statistical power in the resulting load impact estimates. The interim evaluation on results from the summer of 2012 was published in May, 2013. The final evaluation covering activities during the summer of 2013 and 2014 was published in June, 2015. Based on the results, CEIC is considering expansion of CPR offerings in the future.

2.3 DTE Energy (DTE)

Overview. DTE's SGIG project had a total budget of about $168 million (DOE's share of about $84 million) and included a system wide roll-out of 725,000 smart meters and installation of distribution automation equipment on more than fifty feeders and ten substations. DTE's consumer behavior study's initial design involved more than 6,000 residential customers and focused on evaluating customer acceptance and response to various combinations of time-based rates (TOU with a CPP overlay) and IHDs and PCTs.

Treatments. Rate treatments included the implementation of a three-period TOU rate with a CPP overlay during the peak period (weekdays and non-holidays 3 – 7 p.m.). Critical peak events were announced with day-ahead notice to participating customers. Up to 20 critical peak events could be called each year. Control and information technology treatments included the deployment of IHDs and PCTs. In addition, all customers participating in the study received web portal access, customer support, and a variety of education materials.

Design. The study's experimental design involved a randomized controlled trial with denial of treatment for the control group. A simple random sample of AMI-metered residential customers in the service territory who meet certain eligibility criteria received an invitation to opt-in to the study where participating customers could receive one of several treatments, with the understanding that this treatment is limited in supply. Customers who opted-in were surveyed to ensure they met the eligibility criteria. Those who self-identified as having central air conditioning were randomly assigned either to a control group or to receive an offer to opt-in to one of four studies, each of which includes a TOU with CPP rate design and an offer of: no technology, an IHD only, a PCT only, or both a PCT and IHD. Those who self-identify as not having central air conditioning were randomly assigned either to a control group or to receive an offer to opt-in to one of two studies, each of which included a TOU-CPP rate design and an offer of either no technology or an IHD.

Status. DTE completed its consumer behavior study. The recruitment effort fell short of its goals and so several of the experimental cells had to be dropped or consolidated to maintain, to the degree possible, statistical power in the resulting load impact estimates. The interim evaluation on the results of critical peak event days called in August, 2012 and May, 2013 was published in January, 2014. The final evaluation covering additional critical peak event days during the summer of 2013 was published in August, 2014. Based on the results, DTE is offering the TOU with CPP rate designed for the study to its entire residential population on a voluntary basis.

2.4 Green Mountain Power (GMP)

Overview. GMP (along with VEC) is part of Vermont Transco's SGIG Project which had a total budget of about $138 million (DOE's share of about $69 million) and included deployment of more than 300,000 smart meters and installation of distribution automation equipment on more than forty feeders and ten substations. GMP's consumer behavior study's initial design involved more than 3,500 residential customers and focused on evaluating customer acceptance and response to different time-based rates coupled with information feedback treatments.

Treatments. GMP implemented CPR that provided a payment to customers for reducing electric demand during declared critical peak events, while the price charged for electricity during other times stayed at the customer's existing flat rate. GMP also implemented CPP overlay that slightly lowered the customer's existing standard flat rate but augmented it with a substantially higher price during declared critical peak events. Control and information technology treatments included the deployment of IHDs. This technology provided site-level electricity consumption information and customer notification of critical peak events. Customers also received notification by email, text, and voice message and had web portal access to interval meter data, customer support, and a variety of education materials.

Design. The study's experimental design involved a randomized controlled trial with denial of treatments for the control group and pre-recruitment assignments. AMI-enabled customers who met certain eligibility criteria were randomly assigned to either one of the two control groups (differing by customer's awareness about the study and critical peak events) or one of six treatment groups. Customers assigned to the flat rate with CPP treatment were required to agree to the rate change. Customers assigned to the flat rate with CPR treatment, or one of the control groups, were told of their assignment and could opt-out.

Status. GMP completed its consumer behavior study. The interim evaluation on the results of critical peak event days called in the summer and fall of 2012 was published In November, 2013. The final evaluation covering additional critical peak event days during the summer of 2013 was published in March, 2015. Based on the results, GMP is considering expansion of time-based rate offerings in the future.

2.5 Lakeland Electric (LE)

Overview. LE's SGIG Project had a total budget of about $35 million (DOE's share of about $15 million) and included deployment of more than 120,000 smart meters and supporting communications networks. LE's consumer behavior study's initial design involved more than 2,000 residential customers and focused on evaluating customer acceptance and response to a TOU rate, under both opt-in and opt-out enrollment approaches. This study focused primarily on evaluating the timing and magnitude of changes in residential customers' peak demand and energy usage patterns due to a seasonal three-period TOU rate.

Treatments. Rate treatments included a seasonal three-period TOU rate, where the definition of the peak period (weekdays and non-holidays) differed between summer (2 – 8 p.m. April – October) and winter (6 – 10 a.m. November – March) as did the definition of the shoulder period (summer: 12 Noon – 2 p.m. April – October; winter: 10 a.m. – 12 Noon and 7 – 10 p.m. November – March). All customers participating in the study received web portal access, customer support, and a variety of education materials, including a bill calculator.

Design. The study's experimental design involved a randomized controlled trial with delayed treatment for the control group. Opt-in and opt-out enrollment approaches were evaluated. For opt-in, the pool of eligible AMI-enabled residential customers in the service territory allocated for this part of the study received an invitation to join the study and receive the rate treatment, with the understanding that the application of this treatment could be delayed by one year. Opt-in customers were then randomly assigned to either receive the rate treatment or remain on their existing inclining block rate. Those who remained on the existing rate acted as a control group during 2012 and were then offered the new rate in 2013.

For opt-out, the pool of eligible AMI-enabled residential customers in the service territory received notification that they were chosen for a study and automatically received the rate treatment. Customers who did not opt-out were randomly assigned either to receive the rate treatment or to remain on their existing inclining block rate. Those who remained on their existing rate acted as a control group during 2012, and then were placed on the new rate in 2013.

Status. LE completed its consumer behavior study. The interim evaluation on the results from 2013 was published in February, 2015; and the final evaluation from 2014 activities was published in July, 2015. LE is currently offering the TOU rate designed for the study to its entire residential population.

2.6 Marblehead Municipal Light Department (MMLD)

Overview. MMLD's SGIG Project had a total budget of about $2.6 million (DOE's share of about $1.3 million) and included system wide deployment of about 10,000 smart meters and supporting communications networks. MMLD's consumer behavior study's initial design involved about 500 customers and focused on evaluating the timing and magnitude of changes in customer peak demand and energy usage patterns from a flat rate with CPP overlay. MMLD was also interested in assessing residential customer acceptance and retention associated with this type of rate design.

Treatments. Rate treatments included the application of a flat rate with a CPP overlay with up to a six-hour period (12 – 6 p.m.) for critical peak events on non-holiday weekdays from June through August. Customers were notified of critical peak events, which were called in conjunction with ISO New England demand response events, by 5 p.m. the day before. Participants could receive notification for up to twelve critical peak events a year during the study. All customers participating in the study received web portal access, customer support, and a variety of education materials.

Design. The study's experimental design involved a randomized controlled trial with delayed treatment for the control group. Residential customers who met certain eligibility criteria received an invitation to opt-in to a study and receive the flat rate with CPP overlay treatment with the understanding that the application of this treatment could be delayed by one year. Customers who opted in were randomly assigned to either the rate treatment or their existing flat rate, which served as the control group for the first year of the study (summer, 2011). All participating customers received the rate treatment in the second year of the study (summer, 2012).

Status. MMLD completed its consumer behavior study. The interim evaluation on results from 2011 was published in May, 2012. The final evaluation covering 2012 was published in June, 2013. Following the study, MMLD decided not to expand deployment of time-based rates in spite of the sizable peak demand reductions they produced and indicated a preference for using direct load control programs to manage peak demands.

2.7 Minnesota Power (MP)

Overview. MP's SGIG Project had a total budget of about $3 million (DOE's share of about $1.5 million) and included deployment of about 8,000 smart meters, supporting communications networks, and installation of distribution automation equipment on one of its feeders. MP's consumer behavior study's initial design involved more than 4,500 residential customers and was implemented in two phases. Phase one evaluated customer acceptance and response to different forms of information feedback. Phase two evaluated these same issues but applied to a TOU rate with a CPP overlay.

Treatments. Phase one information feedback treatments included the development of a web-portal that provided randomly assigned customers with access to consumption data at varying levels of resolution and latency: (1) monthly aggregated data provided on a monthly basis (this was the control group); (2) daily aggregated data provided on a daily basis; or (3) hourly aggregated data provided on a daily basis (required installation of a smart meter). For Phase two MP implemented a two period TOU rate that augments its existing flat rate and includes a 13 hour peak period (i.e., 8 a.m. – 10 p.m.) each weekday. In addition, MP tested the effects of overlaying, during various blocks of the peak period, a higher price on critical peak event days. Customers received day-ahead notice of critical peak events, called when a major energy event was taking place in the Midwest Independent System Operator markets or on MP's system. Participants were to be exposed to no more than 160 hours of critical peak events per year of the study.

Design. Phase one of the study's experimental design involved a randomized controlled trial with denial of treatment for the control group. All residential customers in a given geographical area who met certain eligibility criteria received an invitation to opt-in to a study where participating customers can gain access to a web portal and receive one of three information feedback treatments. Customers who opted -in were surveyed, stratified, and randomly assigned to receive one of the three web portal information feedback treatments.

Because of recruitment shortfalls, MP decided to augment the study sample. All AMI-enabled residential customers who passed up the original offer to join Phase one participants were stratified and randomly assigned to receive one of the three information feedback treatments. These customers were notified of this opportunity and allowed to opt-out of the treatment by choosing to not access the information now made available to them via the web portal.

Phase two used a within-subjects design. All customers with installed smart meters, and others who met certain eligibility criteria and had a smart meter installed, received an invitation to opt-in to a study where participants received the rate treatment for one year.

Status. MP completed both Phase one and two of its study. The interim evaluation of results from Phase one (i.e., the summer of 2012) was published in March, 2014. MP completed Phase two in the fall of 2015 and is currently finalizing its final evaluation report. Customers on the Phase two rate were allowed to continue taking service on it until the utility while the utility considers whether or not to expand time-based rate offerings in the future to the entire residential population.

2.8 NV Energy (NVE) – Nevada Power (NVP) and Sierra Pacific Power (SPP)

Overview. NV Energy's SGIG Project had a total budget of about $278 million (DOE's share of about $139 million) and included deployment of about 1.2 million smart meters, supporting communications networks, and customer systems including PCTs and web portals. NV's consumer behavior study initial design involved more than 16,000 customers in two service territories: Nevada Power (NVP) (serves about 9,000 customers) in the southern part of the state, and SPP (serves about 7,000 customers) in the northern part of the state. NV Energy's consumer behavior study's focused on evaluating the timing and magnitude of changes in residential customer peak demand and energy usage patterns due to a seasonal multi-period TOU rate with a CPP overlay. NV was also interested in assessing residential customer acceptance, retention, and response associated with enabling technologies and energy education efforts.

Treatments. Rate treatments included the application of a multi-period TOU rate that used a five-hour peak period (2 – 7 p.m. at NVP; 1 – 6 p.m. at SPP) with rates that differ depending on the time of year (shoulder summer, June and September; core summer, July and August; and winter, October – May at NVP; and core summer, July – September and winter, October – June at SPP). NV Energy was augmenting the TOU rate with a substantially higher critical peak price (TOU-CPP) during a 4-hour weekday critical peak period in the summer (June – September 3 – 7 p.m. at NVP; July – September 2 – 6 p.m. at SPP). The CPP involved day-ahead notice to participating customers when forecasted temperatures, system demand, or wholesale market prices were expected to be very high and/or when system emergency conditions were anticipated. Study participants could be notified for no more than 18 critical peak events a year for NVP and 16 for SPP.

Control and information technology treatments included the deployment of PCTs. In addition, all customers participating in the study received web portal access. Education treatments augmented the customer web portal access with a curriculum designed to educate customers about energy, energy usage, energy costs and rates, and energy management. Study participants in NV Energy's enhanced education treatments were provided with information, examples, training, and feedback through a combination of written and online materials and experiences.

Design. The study's experimental design involved a randomized encouragement design. A stratified random sample of AMI-enabled customers in the service territory who met certain eligibility criteria were assigned to one of two pools of customers: one acted as the control group (i.e., remained on the existing flat rate without receiving an invitation for the time-based rate, technology or enhanced education) while the other received an invitation to opt-in to the study where participating customers received a single specific offer of treatment that was a combination of the rate, control/information technology, and/or education material. Offers to participate were randomized from the pool of eligible customers until samples size goals were achieved. Data from a sample of customers who were offered but declined the treatments were included in the study as was data from customers in the control group who were not offered the treatments.

Status. NV Energy's completed its consumer behavior study. Its interim evaluation extensively covered market research and load impact analysis results during the first year of the study (January, 2013 – February, 2014) and was published in August, 2015. The final evaluation focused more narrowly on major takeaways from all analysis efforts during the entirety of the study period (January, 2013 – February, 2015) and was published in March, 2016. The utility transitioned all of their study participants onto their existing TOU rate and extended an offer to participate in one of the utility's demand response programs.

2.9 Oklahoma Gas and Electric (OG&E)

Overview. OG&E's SGIG Project had a total budget of about $293 million (DOE's share of about $130 million) and included system wide deployment of about 790,000 smart meters, supporting communications networks, customer systems for about 48,000 customers, and installation of distribution automation equipment on about fifty feeders. OG&E's consumer behavior study's initial design involved about 5,000 residential, and more than 1,000 small commercial customers. OG&E's study centered on evaluating the timing and magnitude of changes in residential and small commercial customer peak demand and energy usage patterns from several types of time-based rates, IHDs, and PCTs.

Treatments. OG&E tested two rate designs: a two-period TOU rate with a variable peak pricing (VPP) component and a TOU with a CPP overlay. The VPP and TOU with CPP overlay used a five-hour peak period (2 – 7 p.m.) during non-holiday weekdays in the summer (June to September). The VPP peak period price was set to one of four different pre-determined levels with day-ahead (by 5 p.m.) notice. OG&E provided customers at least two hours' notice of critical peak events and each event lasted no more than eight hours. Critical peak events were called under conditions of high expected temperatures or system demand, or to avoid system emergencies.

Control and information technology treatments included the deployment of IHDs and PCTs. In addition, all customers participating in the first year of the study received web portal access, customer support and a variety of education materials. All customers in the service territory received access to the web portal during the second year of the study.

Design. The study's experimental design involved a randomized controlled trial with denial of treatment for the control group and pre-recruitment assignment. AMI-enabled residential and small commercial customers who met certain eligibility criteria were stratified and randomly assigned to one of eight treatment groups, or to the control group. These customers received an invitation to opt-in to a study and receive one of several treatments, with the understanding that this treatment was limited in supply, but were not notified of their assignment at that time. Customers who opted-in were screened and surveyed for eligibility.

Status. OG&E completed its consumer behavior study. The interim evaluation covered activities during the summer of 2010 and was published in March, 2011. The final evaluation covers activities during the summer of 2011 and was published in August, 2012. Based on the results of the study, OG&E decided to roll-out the VPP rate programs and offer free PCTs to about 140,000 residential customers across its service territory.

2.10 Sacramento Municipal Utility District (SMUD)

Overview. SMUD's SGIG Project had a total budget of about $307 million (DOE's share of about $128,000 million) and included system wide deployment of more than 615,000 smart meters, supporting communications networks, customer systems for about 10,000 customers, and installation of distribution automation equipment on about 170 feeders. SMUD's consumer behavior study's initial design involved about 57,000 residential customers. SMUD's study focused on evaluating the timing and magnitude of changes in residential customer peak demand patterns due to various combinations of enabling technologies, different recruitment approaches (i.e., opt-in vs. opt-out), and several types of time-based rates.

Treatments. Rate treatments included the implementation of three time-based rate programs in effect from June through September: (1) a two-period TOU rate that included a three-hour peak period (4 - 7 p.m.) each non-holiday weekday; (2) a flat rate with CPP overlay; and (3) a TOU rate with a CPP overlay. Customers participating in any of the CPP overlay treatments received day-ahead notice of critical peak events that were called when wholesale market prices were expected to be very high and/or when system emergency conditions were anticipated. CPP participants could be notified of no more than 12 critical peak events during each year of the study.

Control and information technology treatments included deployment of IHDs. SMUD offered IHDs to all opt-out customers in any given treatment group and to more than half of the opt-in customers in the treatment group. All participating customers receive web portal access, customer support, and a variety of education materials.

Design. Due to the variety of treatments, the study included three different experimental designs: (1) randomized controlled trial with delayed treatment for the control group, (2) randomized encouragement design, and (3) within-subjects design. For all cases, AMI-enabled residential customers in SMUD's service territory were initially screened for eligibility and randomly assigned to one of the seven treatments or the control group.

For the two treatments included in the randomized controlled trial, recruit and delay, portion of the study, customers received an invitation to opt-in and receive an offer for a specific treatment. Upon agreeing to join the study, customers were told if they were to begin receiving the rate in the first year of the study or in the summer after the study was completed.

For two of the three treatments that were included in the randomized encouragement design, customers were told that they had been assigned to a treatment but had the ability to opt-out of this offer. Those who did not opt-out received the indicated treatment for the duration of the study. Those who did opt-out were included in the study but did not receive the indicated treatment.

For the two treatments that were included in the within-subject design, customers were told they had been assigned to either the flat rate with CPP overlay treatment or the TOU rate with CPP overlay treatment with technology. In the former case, customers only had the ability to opt-in to this specific treatment. In the latter case, customers only had the ability to opt-out of this specific treatment.

Status. SMUD completed its consumer behavior study. The interim evaluation covered activities during the summer of 2013 and was published in October, 2013. The final evaluation covered activities during the summer of 2014 and was published in September, 2014. Based on the results of their study, SMUD is consolidating all pricing tiers to produce a single flat rate for residential customers in 2018 and plans to transition all residential customers to a default TOU rate thereafter.

2.11 Vermont Electric Cooperative (VEC)

Overview. VEC (along with GMP) was part of Vermont Transco's SGIG Project which had a total budget of about $138 million (DOE's share of about $69 million) and included deployment of more than 300,000 smart meters and installation of distribution automation equipment on more than forty feeders and ten substations. VEC's consumer behavior study's initial design involved more than 3,500 residential customers and focused on evaluating the timing and magnitude of changes in customer peak demand and energy usage patterns from a three-period TOU rate with variable peak prices, enhanced customer service-based information feedback, and enabling control and information technologies.

Treatments. Rate treatments included the application of a three-period TOU rate with a variable peak pricing (VPP) component, where the peak period price changed to reflect the average ISO New England day-ahead marginal locational price of electricity for those hours for the Vermont load zone. The definition of each period differed seasonally. During the summer (April – September), the peak period covered weekdays and non-holidays 11 – 5 p.m.; the shoulder period covered weekdays and non-holidays 5 – 10 p.m.; and the off-peak period covered all other hours. During the winter (October – March), the peak period covered weekdays and non-holidays 4 – 8 p.m.; the shoulder period covered weekdays and non-holidays 11 a.m. – 4 p.m. and 8 – 10 p.m.; and the off-peak period covered all other hours. Control and information technology treatments included the deployment of IHDs, proactive customer services, and home energy management systems.

Design. The study's experimental design involved a randomized controlled trial with denial of treatment for the control group. A random sample of AMI-enabled residential customers in the service territory who met certain eligibility criteria received an invitation to opt-in to the study and receive one of several treatments, with the understanding that these treatments were limited in supply. Customers who opted-in were screened and surveyed for eligibility and randomly assigned to one of the three treatments or the control group. The study was originally designed to transition all treatment customers from their existing flat rate to VPP, while all control customers were to remain on their existing flat rate for the duration of the study.

However, due to attrition problems experienced in the first few months of the study that led to questions about the comparability of the customers in the control group to the remaining pool of treatment customers, VEC decided to alter the initial experimental design. To provide the best opportunity to estimate precise load impacts from VPP, VEC redesigned the study for the second year. This second part of study was designed such that all AMI-enabled residential customers in the service territory who met certain eligibility criteria received an invitation to opt-in and either receive the VPP treatment or remain on their flat rate (i.e., randomized controlled trial with denial of treatment for the control group).

Status. VEC completed its consumer behavior study. The interim evaluation covers activities during the summer of 2011 and is primarily a process evaluation because the difficulties with attrition and sample sizes precluded quantitative analysis. This was published in October, 2013. The final evaluation, published in September, 2015, covered the second part of the study and included results from June, 2013 through June, 2014. Future plans for implementation of time-based rates will be determined following completion of the study.

3. Recruitment Approaches

Social scientists have long recognized a behavioral phenomenon called the default effect or status quo bias –when facing choices that include default options, people are predisposed to accept the default over the other options offered. Historically, recruitment of residential customers to participate in time-based rates has almost exclusively involved opt-in approaches. This theory may help explain why utilities have been challenged for years in getting residential customers to widely accept voluntary time-based rate offers.

Today, with expanded deployment of AMI, increasing numbers of utilities and states are considering time-based rates as the default service option (opt-out). However, given limited industry experience with such recruitment approaches, especially at the residential level, there have been questions about the extent to which the default effect would apply to decisions about remaining on time-based electric rates after being placed on them.[23] Furthermore, various industry stakeholder groups have raised concerns about exposing vulnerable groups of customers (e.g., elderly and lower income) to time-based rates in a default environment.

Customer choices are key factors for the effectiveness of time-based rates in achieving their objective of reducing electricity demand during peak periods.[24] These choices include customer decisions to enroll and continue with new rates, their acceptance and use of various customer systems, such as IHDs and PCTs, and decisions to change their patterns of electricity consumption.

Two CBS utilities (SMUD and LE) have included both opt-in and opt-out recruitment approaches for treatment groups in their studies and have evaluated the impacts on enrollment, retention, and demand reductions. The other CBS utilities used opt-in recruitment approaches exclusively for all aspects of their studies.[25] In general, the CBS utilities were interested in evaluating these different enrollment approaches to answer several key questions about their efficacy, including:

- To what extent does the recruitment approach affect enrollment and retention rates?

[23] Baltimore Gas and Electric is one of the very few examples of a utility that has implemented an opt-out approach for its residential CPR program (Smart Energy Rewards). However, the CPR design results in no risk to customers who chose not to participate during declared critical events.

[24] When conducting experimental studies, the number of customers enrolled in programs needs to be large enough to produce statistically useful sample sizes. For larger-scale roll-outs, enrollment and retention levels need to be large enough to produce sufficient demand reductions to satisfy utility objectives for deferring capacity additions, or improving asset utilization.

[25] For further information on CBS enrollments see "Residential Customer Enrollment in Time-Based Rate and Enabling Technology Programs" LBNL 2013.

- What are some of the key lessons learned about customer engagement under the different recruitment approaches in the implementation of time-based rates?
- What types of bill management tools were employed and how does their application differ based on the recruitment approach?
- What are the effects on the magnitude and variability of demand reductions under different recruitment approaches?
- What are the costs and benefits of implementing time-based rates under different recruitment approaches, and under what conditions and circumstances are the offers cost-effective?
- What are the expected impacts on customer bills from implementing default time-based rates absent any load response, and is there any relationship between these expected bill impacts and participants' actual demand reductions, satisfaction and willingness to continue with the rate after the study ended?

3.1 Enrollment and Retention

If the default effect holds true, then opt-out recruitment efforts would result in much higher enrollment rates than opt-in approaches. Yet, utilities and others in the electric industry expect customers to drop out at higher rates than those recruited under opt-in approaches. Specifically, concerns have been raised that customers defaulted into time-based rates may not be aware of the consequences of their implicit acceptance of the time-based rate until they see their first bills. At that point, there is a concern that customers would be less likely to continue participating once they realize what they have been defaulted into, resulting in more drop outs, lower retention rates and lower customer satisfaction with the utility than under opt-in recruitment approaches.

Figures 2, 3a and 3b show the enrollment and retention rates (year 1 and year 2, respectively) from the SGIG consumer behavior studies by opt-in and opt-out recruitment approaches. Each bar in the figures represents a treatment group within a utility study. Figure 2 shows average opt-out recruitment approaches successfully enrolled approximately 6.2 times more participants than average opt-in recruitment approaches (93% vs. 15%) at 9 of the 10 CBS utilities.[26] This finding is generally consistent with default effect experiences from other industries, products, and services.

[26] Data from OG&E was not included in Figure 2 because comparable enrollment rates could not be determined from their mass media recruitment process. However, OG&E did collect data about customer retention by treatment group. As a result, Figures 3a and 3b include their results.

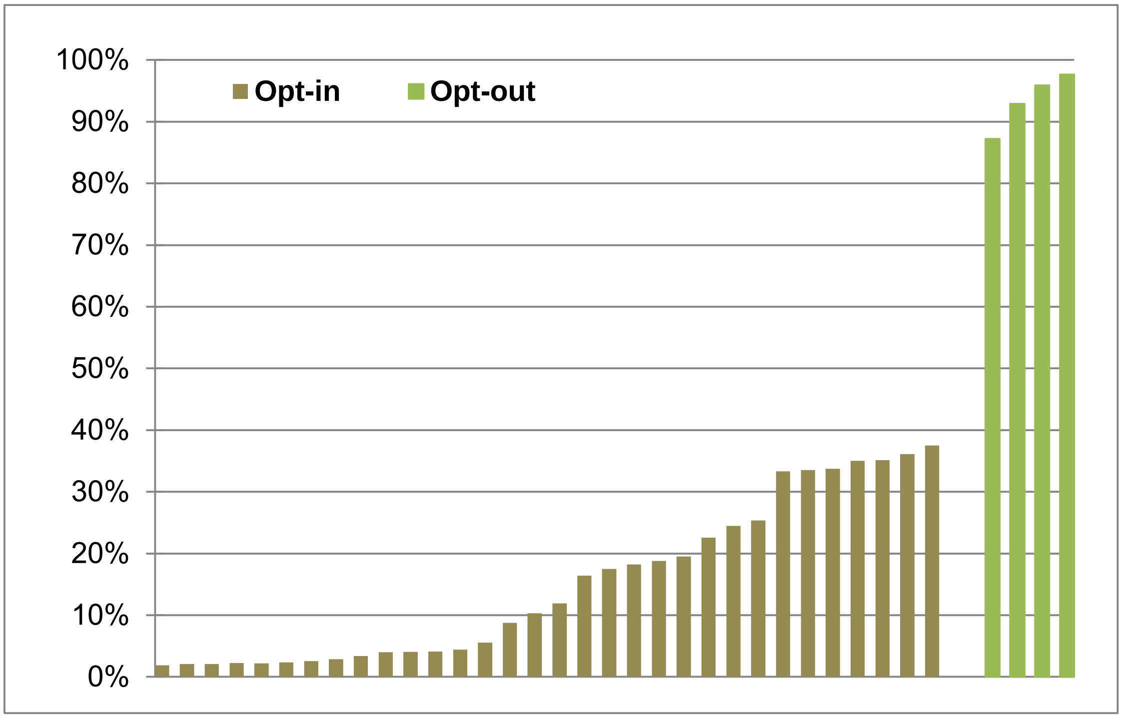

Figure 2. Enrollment Rates for Opt-in and Opt-out by Treatment Group.

Figures 3a and 3b show retention rates for year 1 (9 CBS utilities) and year 2 (5 CBS utilities),[27] respectively. Once customers joined the studies, the figures illustrate that opt-out recruitment did not result in large numbers of drop-outs during either year 1 or year 2 of the study period. In fact, retention rates were roughly the same for both opt-in and opt-out approaches, and didn't noticeably change from year 1 to year 2 of the study, as customers gained more experience with the rates. These results were contrary to the expectations of the CBS utilities.

[27] Not every CBS utility ran a two year study and some who did altered the design in the second year, in which case it was inappropriate to compare year 2 retention rates to year 1 retention rates.

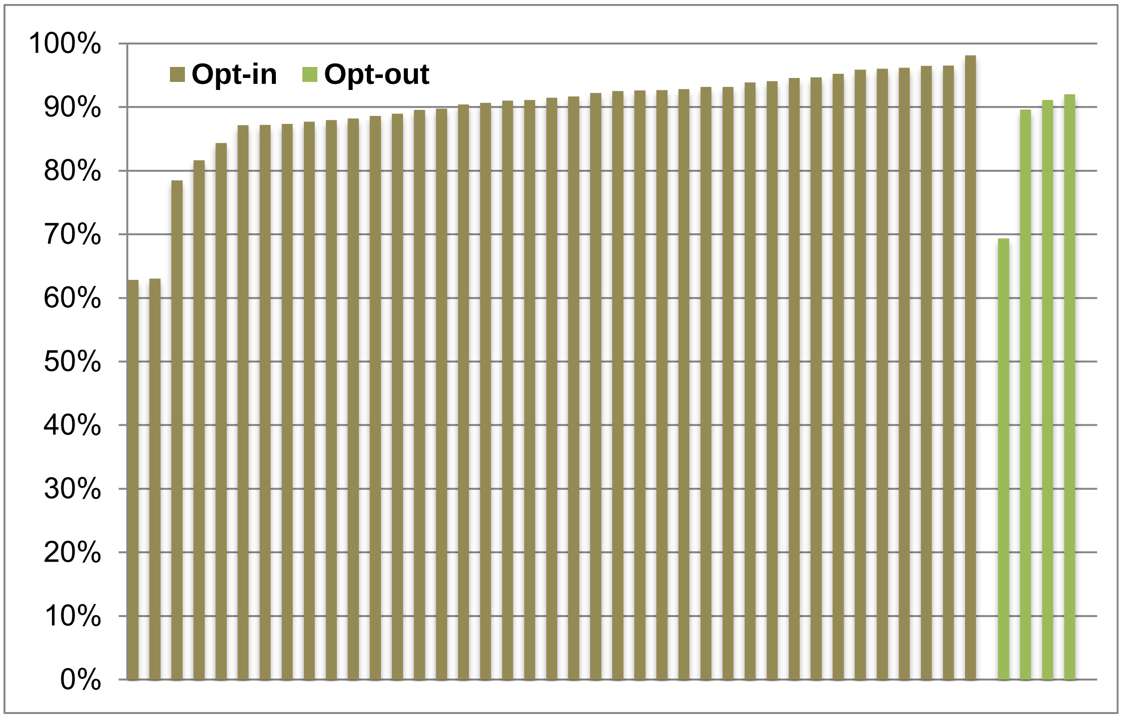

Figure 3a. Retention Rates for Opt-in and Opt-out by Treatment Group (Year 1 Only).

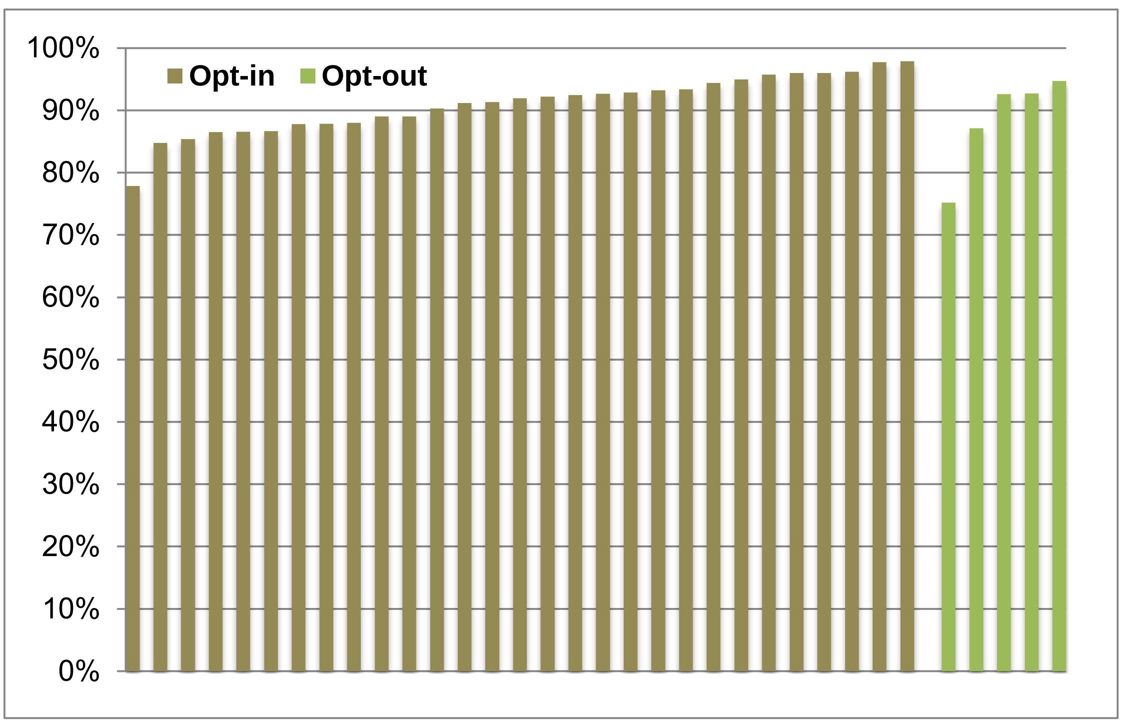

Figure 3b. Retention Rates for Opt-in and Opt-out by Treatment Group (Year 2 Only).

One of the CBS utilities (SMUD) included treatment groups to specifically evaluate the efficacy of opt-in and opt-out recruitment approaches. Figure 4 shows the effects of the different recruitment approaches on enrollment, retention, and dropout rates, and the results are consistent with the findings of the other CBS evaluations, which are shown in Figures 2, 3a and 3b.

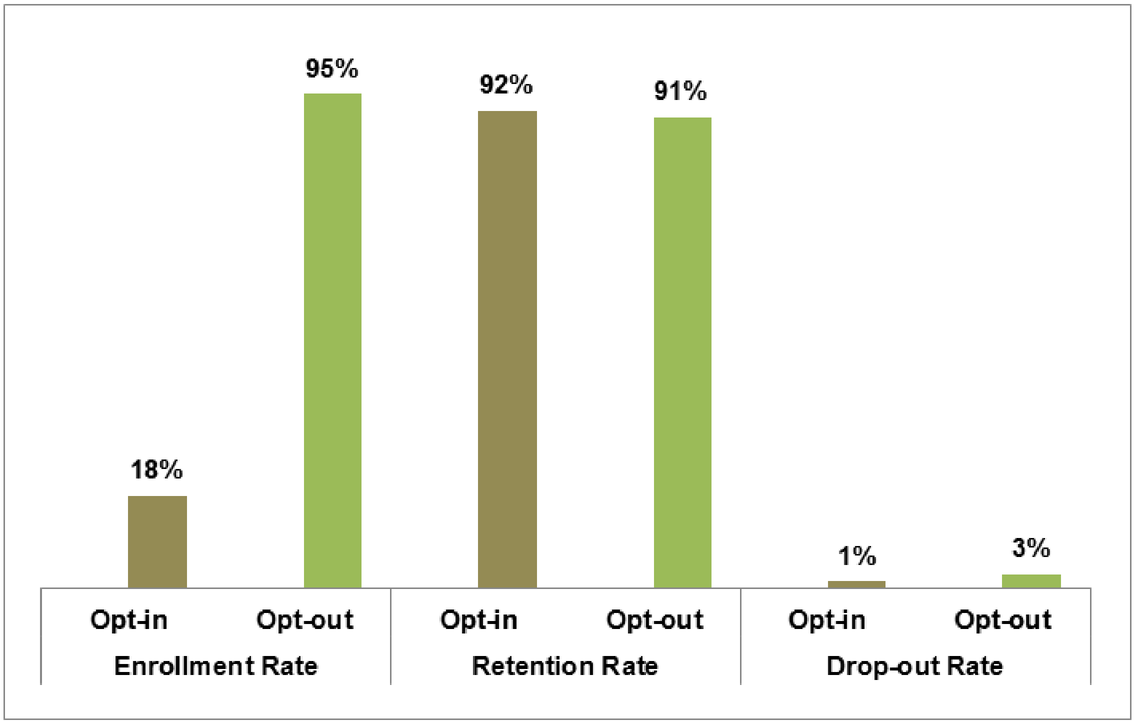

Figure 4. SMUD Enrollment, Retention, and Drop-out Rates for Opt-in and Opt-out.

3.2 Lessons Learned

Successful opt-in enrollments require extensive marketing and outreach to sufficiently raise customer awareness and successfully encourage participation in time-based rates. On the other hand, opt-out recruitment approaches do not require nearly the same level of market research to achieve high enrollment levels. However, marketing and outreach efforts are still required to make customers aware of the rate or program they are being placed into, the process they need to follow to opt-out and the actions they can take to manage the risks associated with the new rate or program. Customer engagement is essential for success under both opt-in and opt-out approaches.

In addition to opt-in and opt-out recruitment approaches, other activities implemented by the CBS utilities in two areas have particular bearing on customer enrollment and retention: (1) Education and Outreach and (2) Recruitment Strategies. Table 3 provides a summary of the lessons learned by the CBS utilities in these areas.[28]

Table 3. Summary of Lessons Learned for Opt-in Enrollments

Topics	Lessons Learned
Education and Outreach	Conduct General Customer Education
	Conduct Market Research
	Test Messages before Using Them
Recruitment Strategies	Conduct Soft Launches and Avoid Holiday Seasons
	Use Multiple Delivery Channels
	Set Realistic Expectations
	Avoid Confusing Messages

For education and outreach, which is especially important for opt-in recruitment approaches, the focus involves raising the knowledge and awareness of customers about new offerings. One challenge is that customers today have busy lifestyles and are bombarded with messages and sales pitches from many different vendors using all types of media, including newspapers, radio, television, phone lines, and the internet. The competition for a customer's attention is intense and the SGIG CBS utilities found they needed to sharper strategies and tactics to be effective.

One of the three key lessons learned for education and outreach involved needs for conducting more general customer education campaigns about utility opportunities for managing electricity demand, and customer opportunities for managing costs and bills. Methods used by CBS utilities for delivering education curricula were many and included public meetings involving small groups of customers in cities, towns, and communities; radio and newspaper advertisements; and web sites, social media and even smartphone apps.

Market research using customer surveys and focus groups was also found to be valuable in understanding customer needs and shaping effective messages. Yet, even with careful market research, the CBS utilities found it important to test messages and marketing materials before directly incorporating them into recruitment materials and sharing them widely with customers.

Successful recruitment strategies typically involve a variety of success factors including the quality and persuasiveness of invitation materials, clarity of messages, thoroughness in following up and

[28] For fuller analysis of lessons learned by CBS utilities in implementing time based rate programs see "Experiences from the Consumer Behavior Studies on Engaging Customers", U.S. DOE, September, 2014.

following through on customer questions and problems, and having the ability to anticipate and prevent common glitches from cascading into major problems.

One of the key lessons learned for effective recruitment strategies was to conduct soft launches[29] and avoid holiday seasons. Several of the CBS utilities found it important to allocate more time than was initially planned between soft and hard launches to implement fixes and make adjustments to messages. The CBS utilities also found that it is highly recommended to avoid soft and hard launches during the holiday season that stretches from mid-November through the first of the New Year. This mistake was made by at least one utility and recruitment rates were unacceptably low during that period.

The CBS utilities also found that use of both traditional (e.g., printed materials, such as letters and brochures, and telephone calls to homes and offices) and new methods (e.g., electronic materials delivered by emails, text messages to mobile phones, web sites, and social media) for delivery of messages was essential.

Setting realistic expectations for customers about the requirements of participation, performance of the devices, and potential bill savings was a key element of success as was the need to avoid the use of confusing messages.

3.3 Bill Management Tools

Several CBS utilities learned from market research that although environmental stewardship and increased reliability of the power system were important messages to promote customer participation in new rate offerings, customers were primarily interested in being able to better manage their electricity bills. Since most residential customers have only taken electric service under flat or inclining/declining block rate designs, bill management means that if they use less, then bills should go down. When time-based rates are introduced, the focus shifts away from using less overall, to shifting use from times when rates are high to times when they are lower. TOU rates, in particular, encourage customers to reduce consumption in high-priced peak periods and shift it to lower priced off-peak periods. CPP and CPR, on the other hand, encourage customers to reduce electricity use during specific hours on specific days of the year. These concepts were new to many customers and required new ways of thinking about electricity consumption and bill management.

[29] “Soft” launches refer to the release of a product, service, or program to a limited audience to gather information about usage and acceptance in the marketplace before making it generally available to a wider audience through a “hard” launch.

To help customers understand how their bills might be affected by particular time-based rate options, utilities have a variety of tools at their disposal. One is that utilities can provide web portals to customers. These internet sites allow customers to access and track their consumption and costs, often including information about how to manage both.

Another tool utilities can offer via the web portals is a bill calculator. This tool allows customers to estimate bill impacts under a variety of different rate designs. In addition, the tool allows customers to simulate how their bills might be affected from different actions (e.g., reduce X% of energy during a critical peak event or shift Y kWh from the peak to off-peak periods).

Once on a new time-based rate, utilities can also provide customers with bill comparisons (also known as shadow bills), either online or in paper form, to show how bills were affected by the new rates.[30] Lastly, utilities can provide bill guarantees[31] for customers taking service under new time-based rates.[32] The guarantees are intended to help customers adjust to new rates and protect them from adverse financial consequences associated with changing rates. Bill guarantees, however, are usually applied for limited periods of time (e.g., 6-12 months).[33]

Table 4 shows the types of bill management tools offered by the CBS utilities included in this report. The table also shows the diversity of tools offered to participating customers. For example, both LE and SMUD included opt-out recruitment approaches, but only LE provided a bill guarantee during a customer's first year on the rate. Only three utilities provided bill calculators to their customers. In general, the CBS utilities tried not to set specific expectations about bill savings during the enrollment phase of their studies. However, most of the studies did identify the opportunity to capture financial benefits (i.e., lower bills) as a reason to participate in the study.

[30] Because incentive-based programs involve a payment to a customer, the rebate is usually explicitly shown on the customer's bill. Thus, a bill comparison tool is not required to identify how a customer's financial position is affected by participation in such a program.

[31] Customers with bill guarantees usually pay the lower of two bills: the one they received under the new rate or the one they would have received under the old rate.

[32] Bill guarantees are generally not required with incentive-based programs unless they include non-performance penalty provisions.

[33] DOE strongly urged the CBS utilities to not apply a bill guarantee for the entire duration of the study, as this would not have been representative of the circumstances surrounding a broad roll-out of the rate offering to customers outside of a study setting.

Table 4. Types of Bill Management Tools					
CBS Utilities in this Report	**Web Portals**	**Bill Calculator**	**Bill Comparison**	**Bill Guarantee**	**Bill Guarantee Period**
DTE	●	●	-	-	-
FE	●	-	-	-	-
GMP	●	-	-	-	-
LE	●	-	●	●	12 months
MMLD	●	-	-	●	12 months
MNP	●	●	-	-	-
NVE	●	-	●	●	12 months
OG&E	●	-	●	●	12 months
SMUD	●	-	-	-	-
VEC	●	●	-	-	-

3.4 Demand Reductions

In addition to enrollment and retention rates, many in the electric power industry believe recruitment approaches can impact demand reductions on a per customer basis. The contention is that customers who opt-in are more likely to understand the rates they are enrolling in as well as what is expected of them to manage consumption and costs. As such, opt-in customers are generally expected to alter their consumption in some way in response to the rate. In contrast, customers who enroll under opt-out approaches may not always be making an affirmative decision: some may not have read the marketing material; some may have read it but did not understand it and never did anything to reject the offer; and others may have learned enough from the marketing material to know they were indifferent to the opportunity, thereby not eschewing it. These types of opt-out customers would not be expected to respond to the time-based rate opportunity even though they were technically enrolled.[34]

SMUD was interested in evaluating this issue and randomly assigned a subset of residential customers to different treatment groups with identical TOU rates but using different recruitment approaches (opt-in and opt-out). Figure 5 shows that per customer demand reductions for SMUD's opt-in customers in both year 1 and year 2 of their study (13% and 11% respectively) were about

[34] Commonwealth Edison's Customer Application Program (CAP) is one of the few examples in the electric industry to illustrate that this theory holds true in reality.

twice as large as they were for opt-out customers (6% for both year 1 and year 2).[35] This result supports the expectation that there are differences in motivation to reduce electricity demand for customers who volunteered to participate (opt-in) versus those placed on the rates by default (opt-out).

SMUD also evaluated identical CPP treatments that were offered to customers under both opt-in and opt-out recruitment approaches. Figure 6 shows that average demand reductions for SMUD opt-in customers over the two years the study was in effect were at least 50% higher than those measured for opt-out customers (13% vs. 12% in year 1 and 22% vs. 14% in year 2), likely due again to possible differences in motivation to reduce electricity demand for customers who opt-in, compared with those who could opt-out.

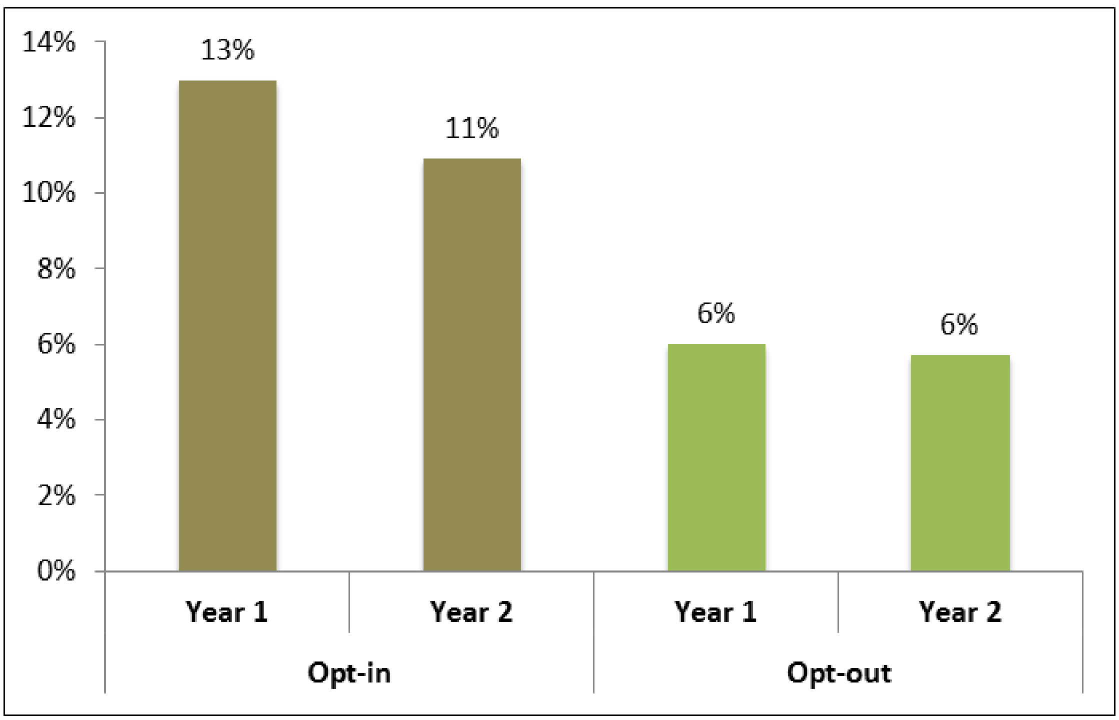

Figure 5. Percent Demand Reductions for SMUD Opt-in and Opt-out TOU Customers.

[35] The difference in these demand reduction estimates was found to be statistically significant, which means they are likely due to the rate and technology treatments rather than random factors. See pages 61 and 62 of the SMUD Interim Evaluation Report.

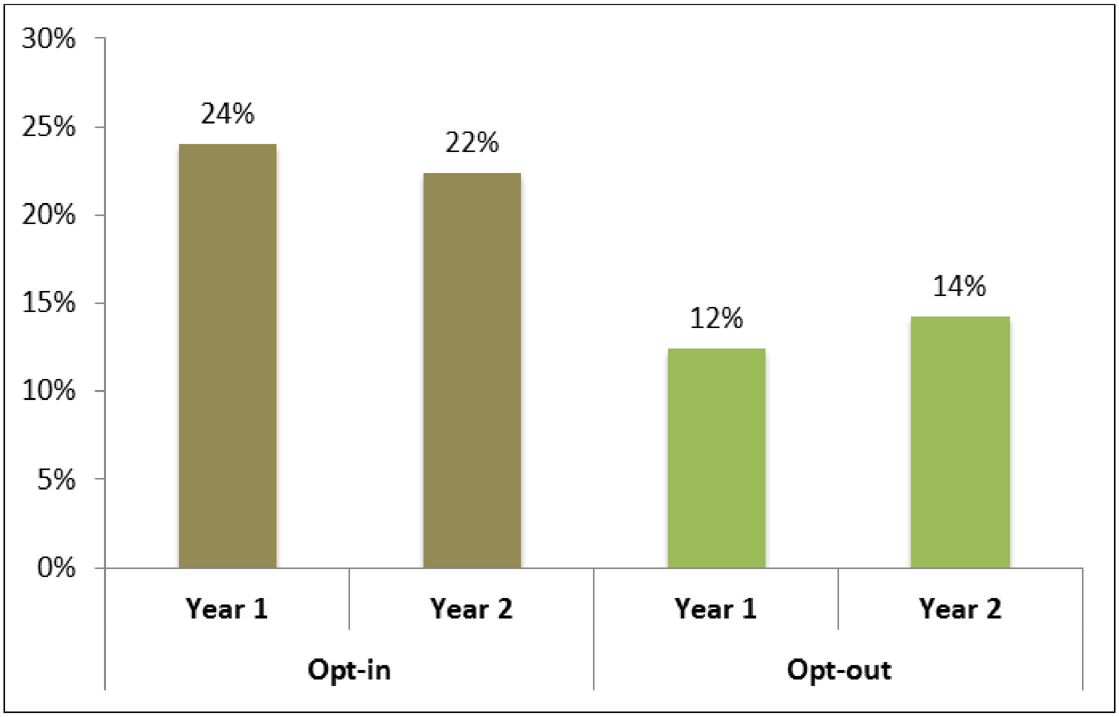

Figure 6. Percent Demand Reductions for SMUD Opt-in and Opt-out CPP Customers.

LE used a different approach to recruiting customers into their study than SMUD but did design a TOU rate that was identical for the opt-in and opt-out customers who took service under the rate in their study. Instead of initially assigning customers to receive an opt-in or opt-out enrollment solicitation, LE issued a general solicitation to its entire residential customer class to voluntarily (opt-in) participate in their TOU study. Of those who rejected this voluntary offer to participate, LE randomly selected a subset of these customers to default (opt-out) onto the TOU study.

This recruitment process may help explain the LE results for demand reductions. Opt-in customers reduced their peak period usage on average by approximately 8%. But the opt-out group did not reduce peak demand at all. Since the opt-out customers had either rejected the offer to voluntarily participate in the TOU rate, or had ignored the offer, one possible explanation is that they were far less engaged and hence less responsive than those who had volunteered.

3.5 Cost Effectiveness

Utility investments typically undergo cost-effectiveness screening by management, which serves as the foundation for regulatory filings to determine whether or not to authorize recovery of prudently incurred expenses. Utilities incur costs in the design and implementation of new time-based rates, including market research, recruitment campaigns, and sometimes some type of customer system such as IHDs and PCTs. The magnitude of recruitment efforts typically differs substantially between opt-in and opt-out approaches.

SMUD evaluated cost effectiveness to assess alternative rate and customer system (IHD) offers, and recruitment approaches, under different scenarios. As shown in Table 5, SMUD found positive benefit-cost[36] ratios for almost all of the scenario offers. However, opt-out recruitment had generally higher benefit-cost ratios for two reasons. First, they involved lower recruitment costs to achieve higher enrollment rates. Second, although each opt-out customer produced lower demand reductions in response to the time-based rates than each opt-in customer, in aggregate the opt-out customers produced much larger total demand reductions which resulted in higher benefits.

Table 5. SMUD Cost Effectiveness Analysis Results[37]

Recruitment Approach	Scenario Offer	Benefit-Cost Ratio
Opt-in	TOU, no IHD	1.19
	TOU, with IHD	0.74
	CPP, no IHD	2.05
	CPP, with IHD	1.30
Opt-Out	TOU, with IHD	2.04
	CPP, with IHD	2.22
	TOU-CPP, with IHD	2.49

3.6 Customer Bill Impacts

The results presented in this section so far show that the average residential customer defaulted onto a time-based rate generally appears willing to continue taking service on the rate and, in the case of SMUD, respond to the rate. However, this average result masks substantial diversity in underlying customer preferences and responses to new rates. In fact, one of the main concerns about defaulting all residential customers onto a time-based rate is that certain subpopulations will be adversely affected, especially financially.

[36] The SMUD benefit-cost results are based on a ten year net present value analysis with the benefits based on deferral value of capacity additions and avoided wholesale energy costs due to reduced loads during high cost periods or shifting usage from higher to lower cost periods. See Section 10.1 "SmartPricing Options – Final Evaluation" SMUD, September 5, 2014.

[37] Source: Table 10-5, page 114 "SmartPricing Options – Final Evaluation" SMUD, September 5, 2014.

Three sub-populations of customers can be defined to help clarify thinking about who might be at risk of being better off or worse off due to default time-based rates:

- **Never takers**: the set of customers that would not actively opt-in to voluntary time-based rate offers, and would actively opt-out when time-based rates are the default;
- **Always takers**: the set of customers that would actively opt-in to voluntary time-based rate offers and would not actively opt-out when time-based rates are the default; and
- **Complacents**: the set of customers who would not actively opt-in to voluntary time-based rate offers, but would not actively opt-out when time-based rates are the default.

The people who opt-in to a voluntary time-based rate would be likewise expected to not opt-out initially if defaulted onto the rate. Thus, how these ***Always Takers*** enroll in the time-based rate would likely not affect their satisfaction from taking service under it. In fact, they may benefit from a default rate in that they are automatically placed on the rate, and don't have to take the time to opt-in voluntarily.

In addition, there is a subpopulation of customers who prefer their existing rate over a time-based rate. These customers will not opt-in when solicited to voluntarily take up the time-based rate and will likewise opt-out if defaulted onto it. These ***Never Takers*** clearly express their preferences when presented with choices.

This leaves a third group of residential customers: the group that will not opt-in to a voluntary time-based rate but neither will they opt-out when TOU is made the default rate design. These ***Complacents*** seem willing to go along with the tariff that they are placed on by the utility.

Using information from SMUD's CBS study that explicitly included both voluntary and default enrollment of residential customers onto identically designed TOU rates, Figure 7 shows a breakout of the estimated proportions of these three subpopulations in SMUD's TOU treatments with an in-home display offer. In using SMUD data to analyze these subpopulations, it was necessary to assume that the group of Always Takers observed in the voluntary enrollment experimental design (19.5% of those solicited to opt-in) would represent the same proportion of, and act similarly to, those Always Takers who could not be directly identified in the default enrollment experimental design.[38]

[38] In other fields, this additional assumption is considered to typically be valid.

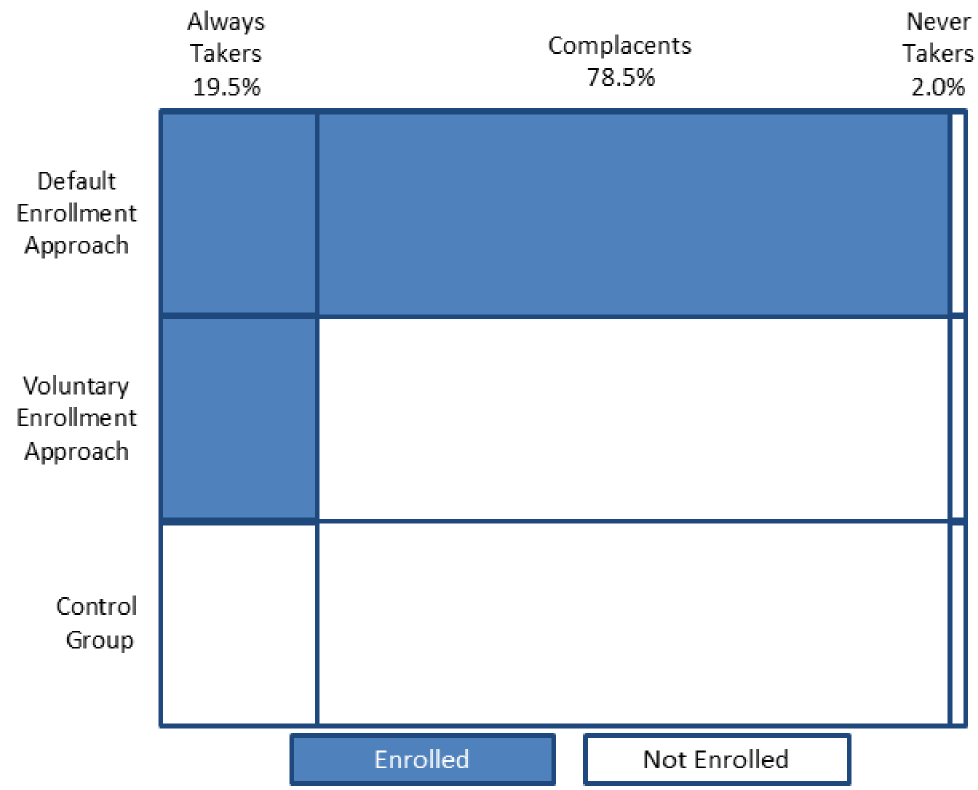

Figure 7. SMUD Residential Subpopulations for Analyzing Opt-in versus Opt-out Bill Impacts.

During the recruitment phase of the study, SMUD did not set explicit expectations with customers that each and every participant would save money by joining the study. Instead, SMUD's marketing material indicated the study's TOU rate created an opportunity for participating customers to save money by managing when they used electricity, not just how much they consumed. It is not clear if customers actually performed any calculations to assess their potential bill impacts from switching to the TOU rate, even without taking into account any change in their electricity consumption behavior.

An assessment of such predicted bill savings, based on an analysis of meter data from all of those who ultimately participated in the study under the default TOU rate, would have shown a distribution like the one in Figure 8.[39] About 22% of the Always Takers and 22% of the Complacent subpopulations, respectively, absent any response to the rate, were predicted to see +/- $5 impact on their bills over the entire four-month summer season the rate was in effect. If that range is

[39] Note that for the purposes of Figure 8 the distribution of predicted bill savings was truncated at +/-$100 per summer. There were 2 out of 12,925 customers with predicted losses greater than $100 and 22 out of 12,925 customers with predicted savings greater than $100.

expanded to +/- $10 for the full summer, 40% of Always Takers and 39% of Complacents would be predicted to see such bill impacts. Broadening the range even further to +/- $20 for the four summer months would capture a majority (66% and 67%, respectively) of both Complacent and Always Taker subpopulations. It is not clear what level of bill impact might have gotten SMUD's customers' attention to either accept or eschew participation in the study, but this similarity of impacts between the two subpopulation suggests that predicted bill impacts may not have been a key driver in the choice to participate in the study.

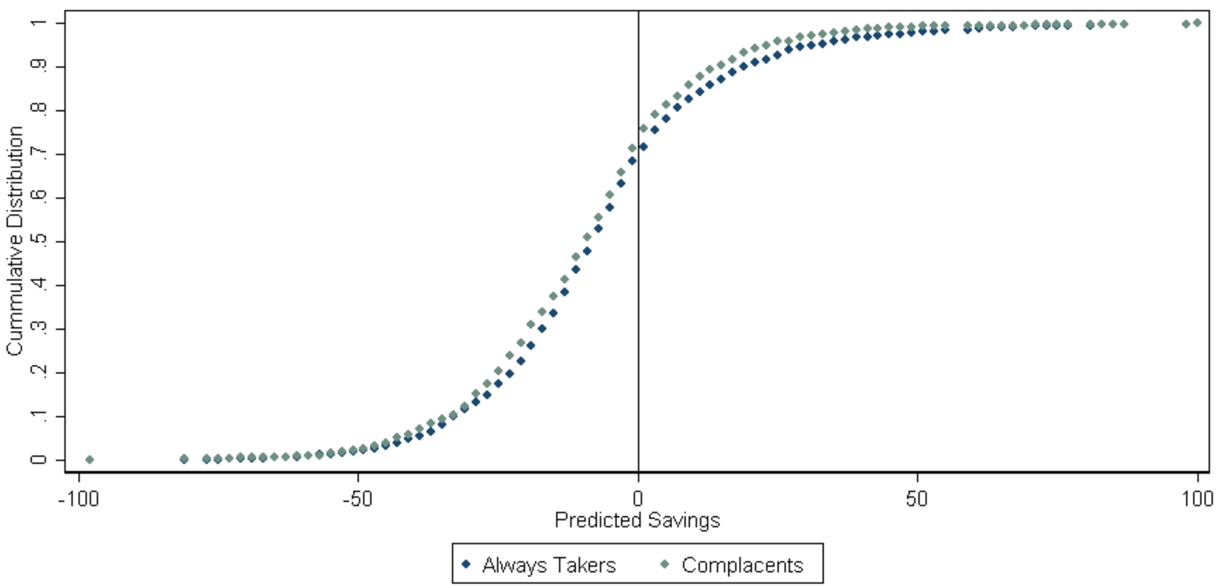

Figure 8. Distribution of Predicted Bill Savings by Customer Subpopulation.

Predicted bill impacts also have implications for the degree to which a participating customer would need to alter their electricity consumption patterns once exposed to TOU in order to achieve any positive bill savings. By breaking the Complacent and Always Taker subpopulations into smaller groups (i.e., quintiles of the predicted full summer bill savings), Figure 9 shows how the average customer in each of these subgroups reduced their peak period load during the study. Always Takers at the extremes of the predicted bill savings (i.e., those with the largest predicted bill losses or savings) exhibited a substantially larger load impact than those who might see more modest bill effects. Complacents exhibited a similar but less extreme version of this phenomenon. This suggests that for some share of both Complacent and Always Taker subpopulations, a large predicted bill impact, regardless of its direction, may increase the desire, willingness, or interest of a customer to manage their electricity consumption relative to one who anticipates that their current consumption patterns is less likely to substantively alter their bill on a TOU rate option.

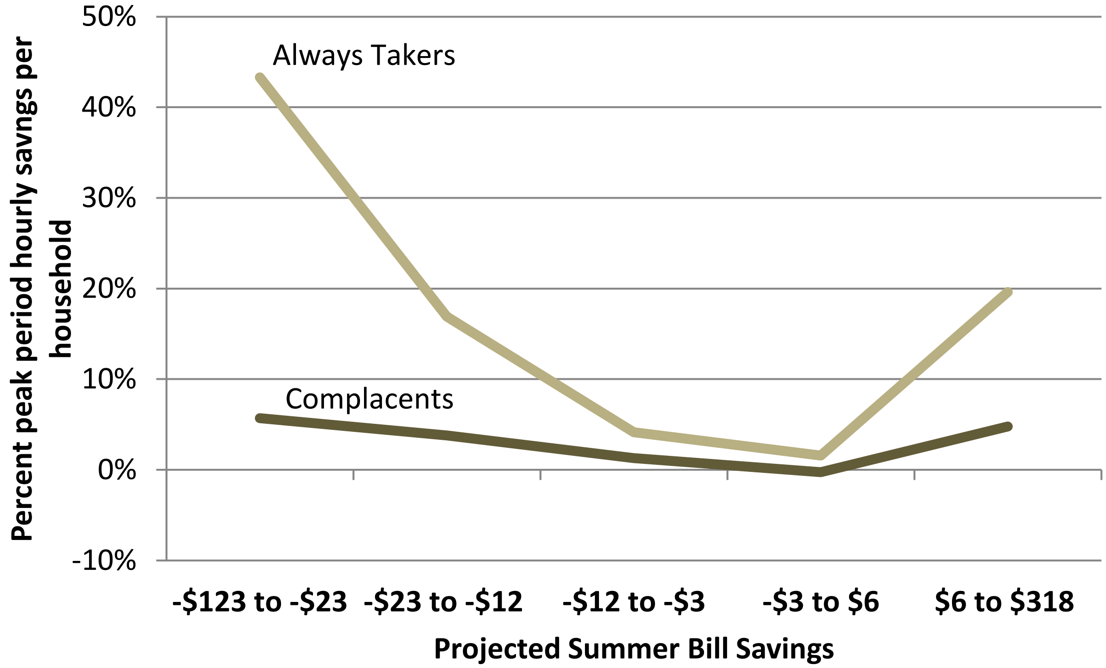

Figure 9.Peak Period Load Impacts by Quintile of Predicted Summer Bill Savings and Customer Subpopulation.

Lastly, the level of the predicted bill savings may also have implications for a participant's overall satisfaction with the default TOU rate, especially as it dictates the degree to which a customer might need to adjust their consumption to actually see a bill reduction. Based on survey responses, predicted monthly bill savings (as shown in Table 6), did not appear to be a major factor in how satisfied customers were with the default TOU rate once exposed to it. In fact, the survey respondents who were predicted to save the most by taking service under such a rate (i.e., greater than $20 for the entire summer) generally had lower satisfaction levels than those predicted to see their bills increase by $5 or more over the course of the summer (e.g., -$10 to -$5). Furthermore, the estimated level of satisfaction with the rate by Complacent survey respondents varied more widely across predicted bill savings and there appeared to be little relationship between the size of the bill impacts and the share of satisfied customers. However, there does appear to be a stronger direct relationship between the size of the predicted bill savings and the degree to which Complacent customers were interested in continuing with the rate. This finding reinforces the notion that a large share of the Complacent subpopulation were seemingly indifferent – they were reasonably satisfied with the rate, regardless of the level of bill savings they achieved, but those who likely lost the most during the study expressed an interest to not continue with the rate when given a direct opportunity to get off of it. In contrast, we see that the Always Takers who responded to the survey expressed lower levels of satisfaction with the default TOU rate as the size of the predicted bill savings increased. This result suggests that the increased effort by those Always Takers with the most to lose from participating in the study was an experience they actually found satisfying. Perhaps the more responding to the rate was required to capture bill savings, the more these customers were willing and interested in doing so. This heightened ability to manage and/or control their bills was seemingly viewed positively, especially for those with the most to gain from doing so.

Table 6. Share of Survey Responses by Subpopulation and Predicted Bill Savings

Predicted Summer Bill Savings ($)	Average Share of Survey Respondents Satisfied with the Existing Rate		Average Share of Survey Respondents Interested in Continuing with the Existing Rate	
	Always Takers	Complacents	Always Takers	Complacents
Less than - $20	94%	73%	96%	69%
-$20 to -$10	87%	92%	96%	89%
-$10 to -$5	89%	67%	92%	82%
-$5 to $5	82%	73%	94%	91%
$5 to $10	85%	100%	91%	100%
$10 to $20	72%	88%	88%	100%
Greater than $20	82%	53%	94%	92%

4. Prices versus Rebates

There is a theory in behavioral science called loss aversion, which states that when people are presented with choices that involve either avoiding a loss or acquiring a gain, the strong preference is to avoid the loss over acquiring the gain (e.g., the thought of losing $20 is more prominent than winning $20). For offers to enroll in CPP and CPR, customers are therefore expected to prefer CPR because there is no possibility of loss, whereas CPP carries the possibility of loss from higher bills.

However, once a customer is on the rate, CPP is expected to produce greater demand reductions than CPR. CPP is expected to be more motivating because customers face the punishment of a loss (through higher bills) if they do not respond, whereas response to CPR only has the benefit of a gain, and so is expected to be less motivating.

Because of the interest in finding the most efficient and cost-effective way to reduce demand during specific periods of time, several of the CBS utilities included evaluations of CPP, CPR or both in their studies. In general, the CBS utilities were interested in answering several key questions about their efficacy, including:

- How does the offer of CPP vs. CPR affect enrollment and retention rates?
- What are the effects on the magnitude and variability of demand reductions from CPP vs. CPR?

4.1 Enrollment and Retention

Utilities and others expect customers to be more likely to enroll in and remain on CPR than CPP. As discussed, the possibility of bill increase from non-performance during critical events under CPP is greater than under CPR, and this could be a motivating factor that decreases enrollment and retention.

GMP included both CPP and CPR treatments in their study and expected enrollment rates for CPR of around 80% versus 15% for CPP. GMP's recruitment experience was very different from this. As shown in Figure 11, GMP found that enrollment rates were about the same for both CPP and CPR. However, GMP did not expect differences in CPP and CPR retention rates, but actual experiences revealed slightly higher retention rates for CPR than CPP, also as shown in Figure 10.

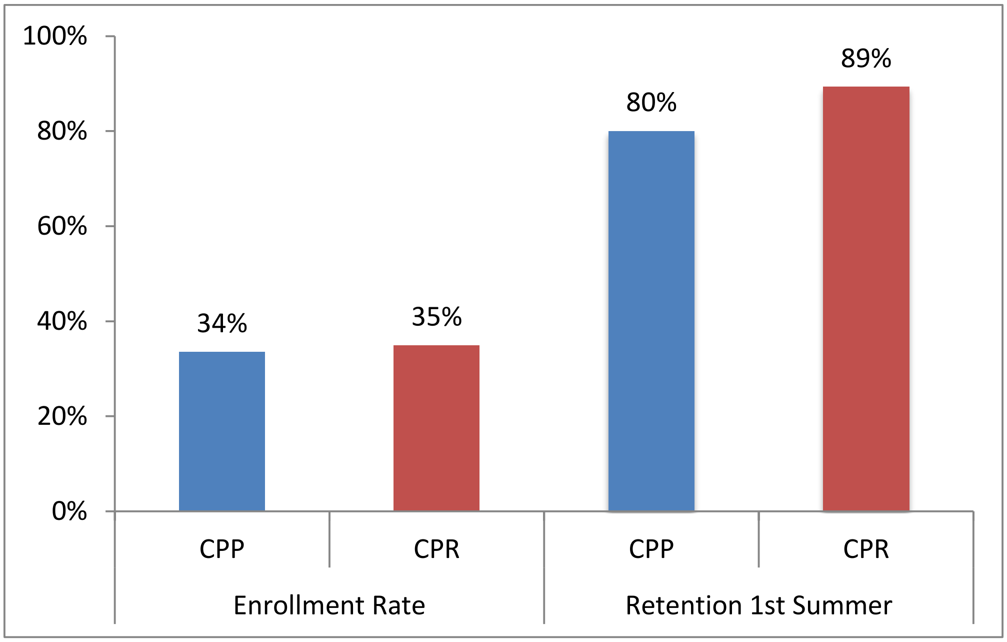

Figure 10. GMP Enrollment and Retention Rates over Time.

4.3 Demand Reductions

Because of the lower potential for higher bills associated with non-response during critical events, many of the CBS utilities expected smaller peak demand reductions for CPR than for CPP. Figure 11 shows average demand reduction during critical peak events across all CBS customers participating in CPP and CPR treatments, including both customers with and without technologies such as IHDs and PCTs. As shown, customers on CPP rates reduced demand by more than twice as much, on average, during critical peak events as those on CPR (25% vs. 11%). This result supports the expectation that demand reductions on a per customer basis under CPP would be greater than those under CPR.

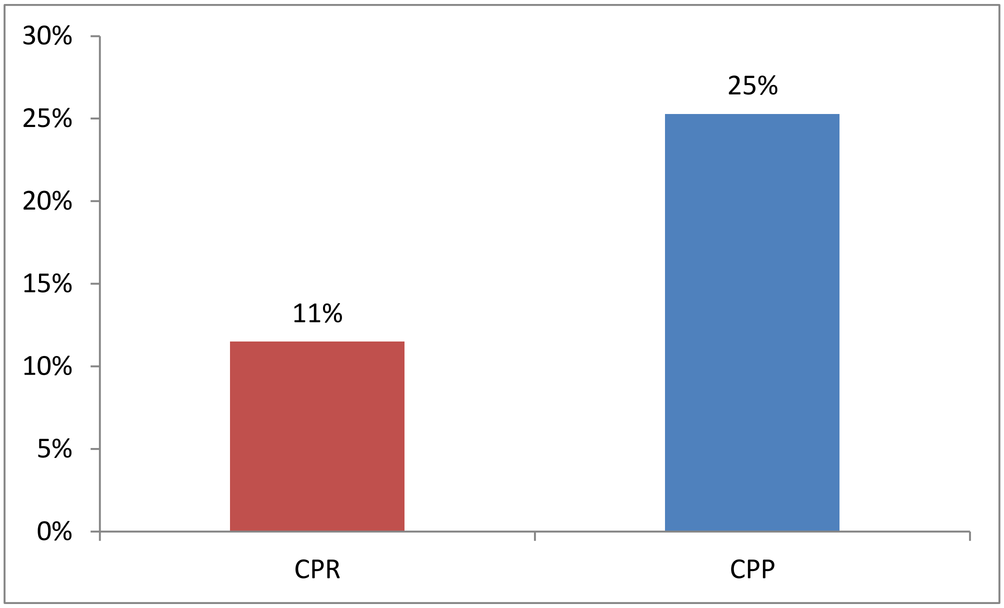

Figure 11. Average Percent Demand Reductions for CBS Customers on CPR and CPP.

However, demand reductions for both CPP and CPR were affected by the use of PCTs. These devices can be programmed to automatically control air conditioners and raise thermostat set points during critical peak events when prices are high (CPP), or when incentives are available (CPR). Each marker in Figure 12 represents one of 72 treatment groups from 8 utilities.

While Figure 11 shows CPR customers with lower demand reductions than CPP customers on average overall, Figure 12 shows that demand reductions for CPP and CPR substantially increased on average for customers with PCTs (15 and 20 percentage points, respectively). This suggests that regardless of the financial incentive to respond (i.e., acquiring a gain via a rebate or avoiding a loss via pricing), PCTs can be an effective tool to mitigate a customer’s loss aversion by allowing them to automate their response during the critical peak events.

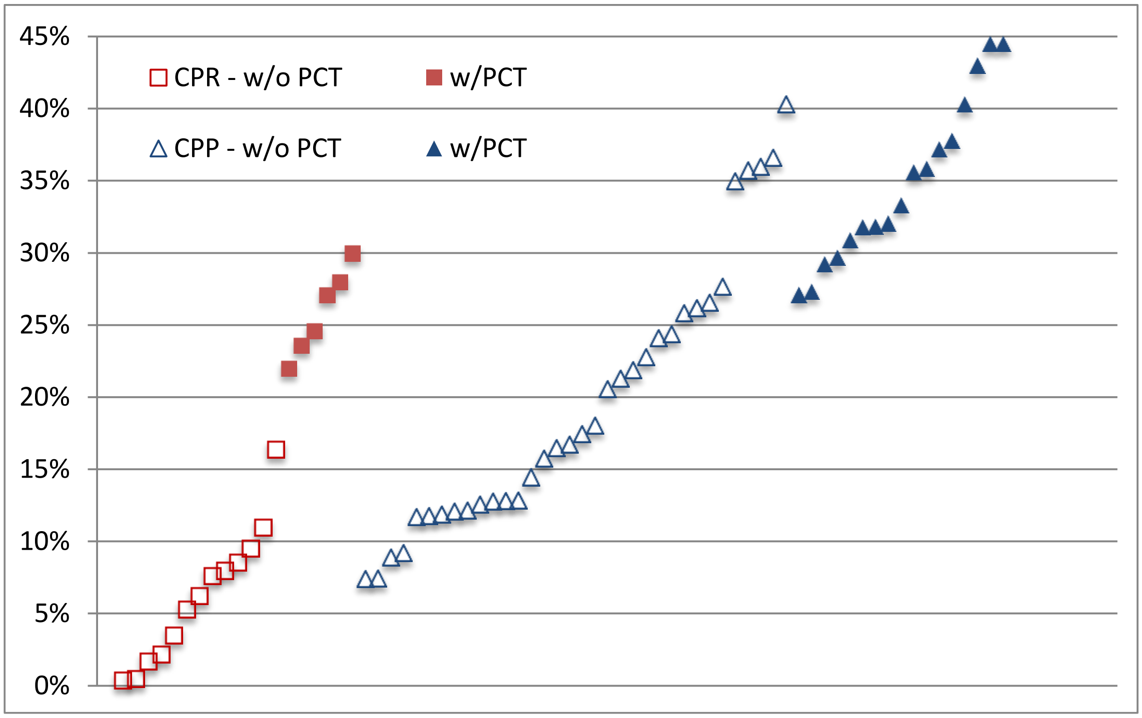

Figure 12. Average Percent Demand Reductions for Customers on CPP and CPR with and without PCTs by Treatment Group.

In addition to the magnitude of the response, system operators are concerned about the reliability and predictability of demand reductions during critical events, including possible differences between CPR and CPP. Figure 13 shows the distribution of average event demand reductions across all critical peak events for each non-PCT CPP or CPR treatment offered by GMP and OG&E, and the single CPP treatment offered by SMUD.[40] While the variability in average demand reductions across events is less for CPP than it is for CPR, demand reductions are still variable in both cases.

Using the New York Independent System Operator's definition of performance factor for its Special Case Resource program[41] (i.e., demand response resources providing capacity service during declared system reliability emergencies), customers on CPP would have had their claimed capacity capability (i.e., overall event average demand reductions) derated (or lowered) by 10% to account for variable performance. In contrast, customers on CPR would have had their claimed capacity capability reduced by three times that amount (30%).

[40] SMUD only provided event-by-event demand reductions for a single treatment cell in their evaluation reports.

[41] New York Independent System Operator (2014). Manual 4 – Installed Capacity Manual. NYISO: Rensselaer, NY. October.

This variability may be an important consideration for utilities seeking to have these resources provide capacity credits cost-effectively, and for system operators to use these rates and programs to help ensure resource adequacy.

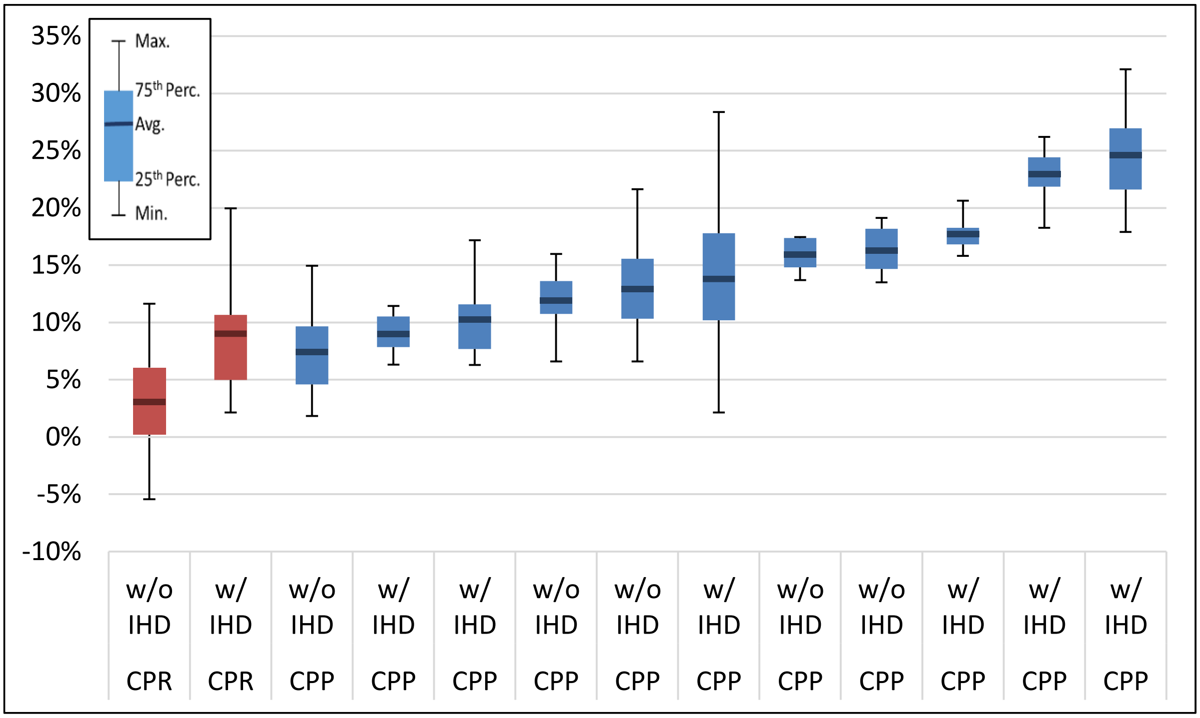

Figure 13. Variability of Per Customer Percent Demand Reductions across All Events for Customers on CPR and CPP (without PCTs) by Treatment Group.

5. Customer Information Technologies

Enabled by AMI, customer information systems are a category of devices that provide near real-time information to customers about their electricity consumption and costs. The category includes IHDs, which are small video screens that receive consumption and cost information from utilities. Several CBS utilities evaluated IHDs directly in their studies. The category also includes web portals which typically provide dashboards and analysis tools for customers to use via the internet in managing their consumption and costs. All of the CBS utilities offered web portals to customers, but none established treatment and control groups to evaluate their efficacy on customer enrollment, retention, or response.

Customer information technologies such as IHDs and web portals provide ways of raising customer awareness of usage levels, consumption patterns, electricity prices, and costs. By bringing attention to the prices and usage patterns, which otherwise might not be readily available or rarely accessed, utilities create opportunities for customers to better understand how their usage directly affects their bills. By having this information, it is expected that customers will have better capabilities for understanding and responding to time-based rates. However, when IHDs are offered by utilities to customers for free (which is frequently done as a means to attract participants and improve demand responses) program implementation costs increase, so it is important to understand if the benefits outweigh the costs of the technologies.

Many of these types of customer technologies are relatively new to the marketplace. Protocols and standards for transmitting price and consumption information to these devices are still evolving. Utilities have low levels of experience integrating the technologies and data streams into back-office systems and customers are unfamiliar with installation and operation procedures. As a result of these and other factors there are often bugs to address and learning curves to climb before performance can be fully evaluated. There are ample opportunities in this area for innovation and experimentation and many vendors are actively exploring new technologies, including software applications for mobile phones and portable computers.

Because of the potential advantages, several of the CBS utilities included evaluations of IHDs in their studies and addressed several key questions about their efficacy, including:

- What are some of the key lessons learned about IHDs in the implementation of time-based rates and incentive-based programs?
- To what extent do offers of IHDs affect enrollment and retention rates?

- To what extent do customers use offered IHDs, and what are the effects on the magnitude and variability of demand reductions?
- What are the costs and benefits of including IHDs and under what conditions and circumstances are the offers cost-effective?

5.1 Enrollment and Retention

Figures 14, 15, and 16 show the results for IHD offers on enrollment and retention rates for three CBS utilities – DTE, GMP, and SMUD. In all cases, the differences in enrollment and retention rates with and without offers of IHDs were small and did not appear to boost enrollment or retention rates, as many in industry expected they would.

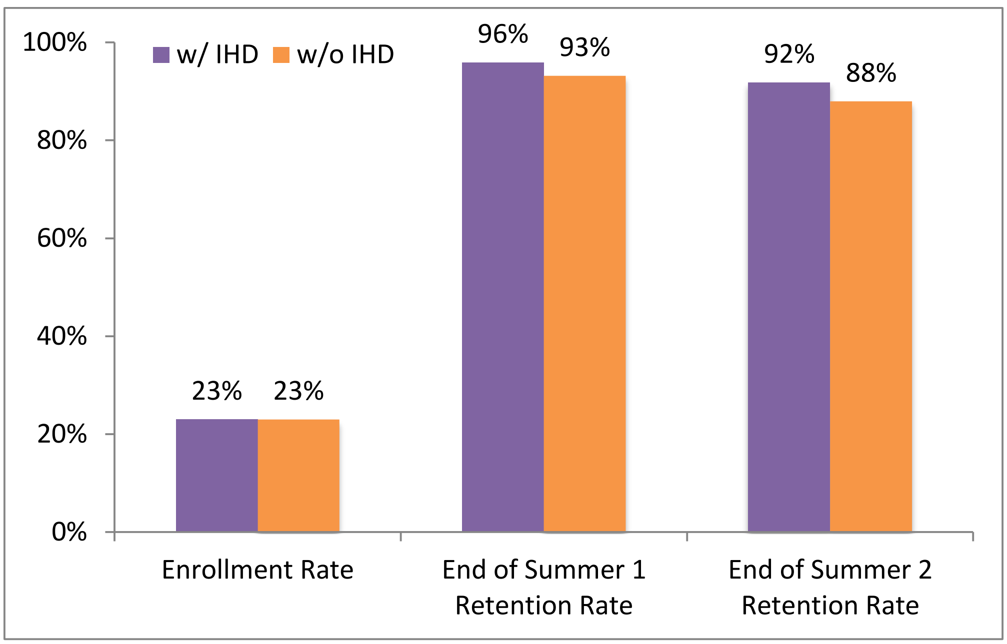

Figure 14. DTE Enrollment and Retention Rates with and without IHDs.

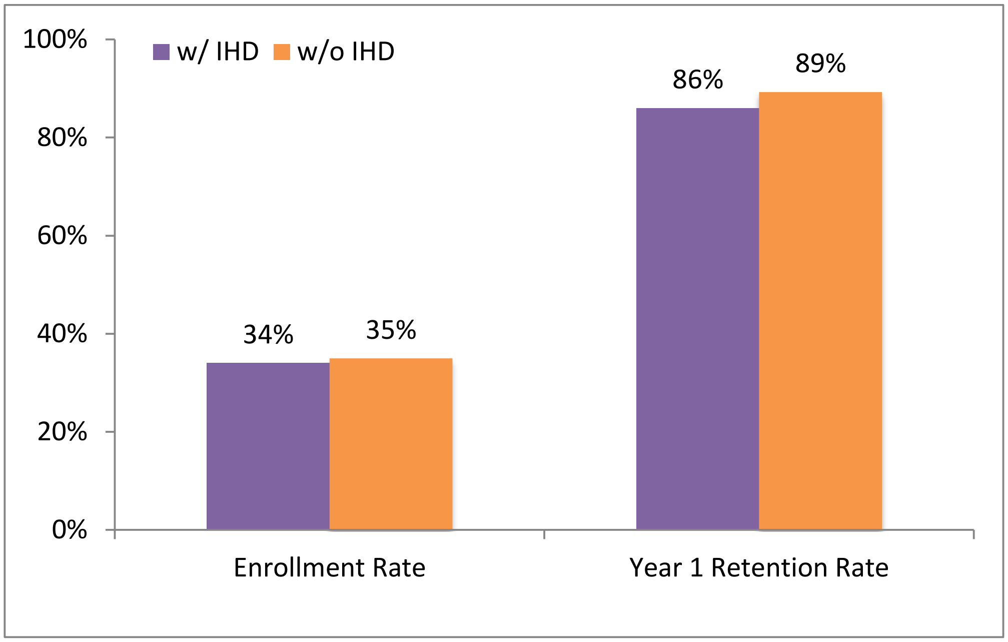

Figure 15. GMP Enrollment and Retention Rates with and without IHDs.

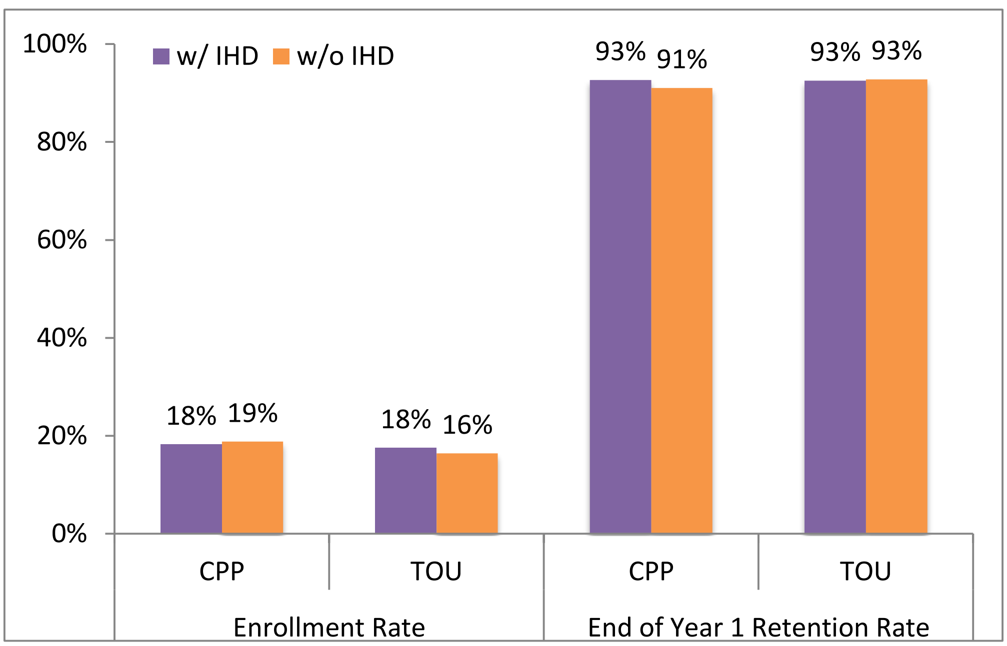

Figure 16. SMUD Enrollment and Retention Rates with and without IHDs.

5.2 Lessons Learned

Several of the CBS utilities encountered implementation problems with IHDs. Numerous instances were reported by most of the CBS utilities of equipment capabilities falling short of vendor statements and marketing material claims. For example, several utilities reported problems in getting timely servicing from vendors who had promised one level of support but delivered something less. In at least one of the studies, the vendor announced they were no longer supporting the device midway through the study and well after the devices had been installed.

SMUD tracked the connectivity of IHDs to better understand the degree to which customers were using them. Table 7 shows that less than 20% of the customers who received an IHD actually had it connected to the utility's system all the time. Instead, the majority of participants in three of the five treatment groups who received an IHD never actually turned it on and connected it to the utility's system.

Table 7: SMUD Connectivity Rates of IHDs

Treatment Group	% Connected All the Time	% Connected Some of the Time	% Never Connected
Opt-in CPP, IHD Offer	11.6%	27.4%	61.0%
Opt-in TOU, IHD Offer	11.6%	22.8%	65.6%
Default TOU-CPP, IHD Offer	18.8%	39.3%	42.0%
Default CPP, IHD Offer	14.3%	42.9%	42.9%
Default TOU, IHD Offer	18.2%	23.1%	58.7%

As a result of these experiences, several of the CBS utilities reported that:

- It is necessary to dedicate time and resources to conduct tests to ensure the equipment does what it is supposed to do, it can work with the other back office utility systems, and that servicing happens quickly and easily.
- In working with vendors, properly worded contract provisions can provide mechanisms for addressing equipment/vendor problems.
- One of the utilities tackled equipment servicing without using vendors by keeping such activities in house and said it was helpful in avoiding problems and customer frustrations with non-functional or poorly functioning equipment.
- Although customers may explicitly agree to receive these devices, some may not necessarily use them.

5.3 Demand Reductions

SMUD evaluated the effects of IHDs on demand reductions under TOU and CPP rate designs for opt-in enrollment approaches. Figures 17 and 18 show that the derived demand reductions for CPP and TOU customers were generally higher for those with IHDs than for those without IHDs, during both years of the study. However, as SMUD's evaluation report points out, these results do not suggest that the difference in the demand reduction estimates can be attributed to the effects of IHDs. According to the final evaluation report, once pre-treatment differences between the sample of customers in the two groups (with and without IHDs) are taken into account, there is no measurable effect of IHDs on demand reductions.

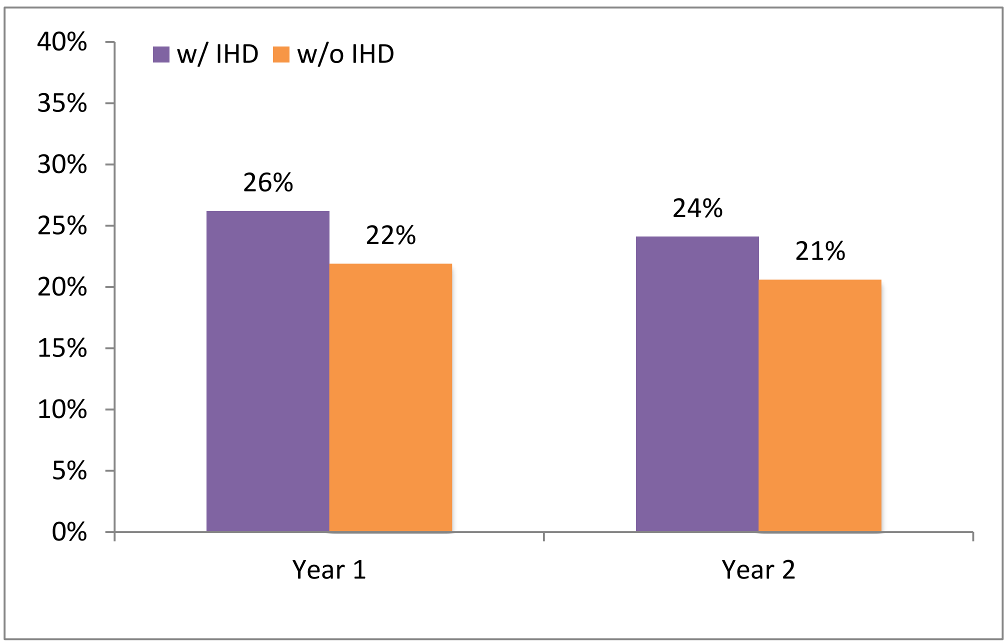

Figure 17. Average Percent Demand Reductions for SMUD's Opt-in CPP Customers with and without IHDs by Year.

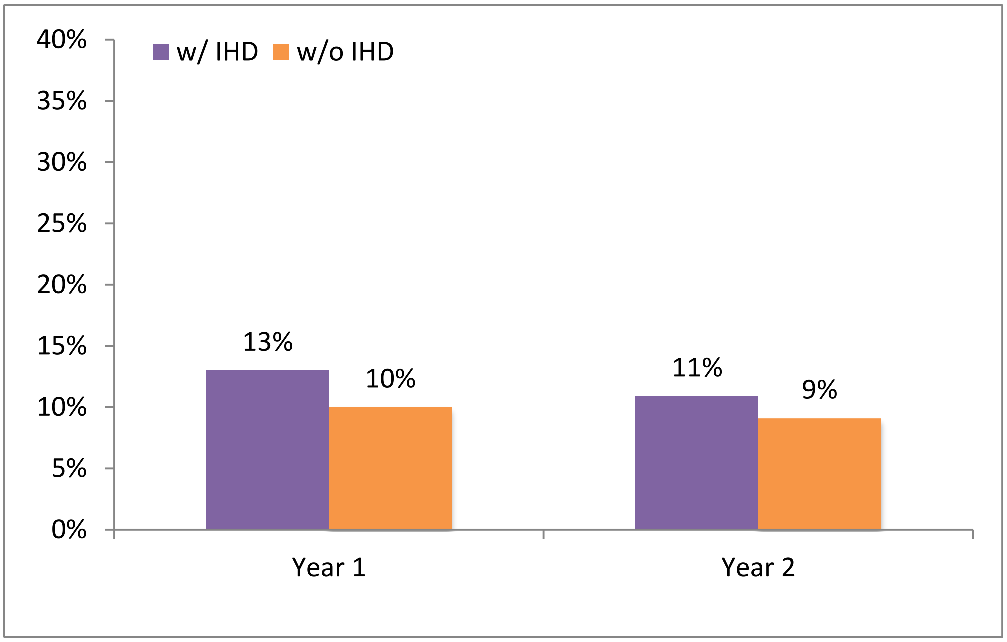

Figure 18. Average Percent Demand Reductions for SMUD's Opt-in TOU Customers with and without IHDs by Year.

In addition to understanding if IHDs can affect average levels of demand reductions, many are interested in knowing the degree to which IHDs may affect the variability of demand reductions over time. If by providing more information to customers about consumption and costs, IHDs were able to reduce variability, they would improve cost-effectiveness by increasing the levels of confidence and certainty for grid operators in the magnitude of demand reductions that involve offers of IHDs.

The data shown in Figure 19 reflect the variability of demand reductions on a per event basis from 3 CBS utilities and 13 treatment groups. On average, the level of variability of demand reductions is largely unaffected by the offer of an IHD making the results generally inconclusive with respect to the capabilities of IHDs to reduce the variability of demand reductions. Further study and analysis is needed to fully assess the role of IHDs to affect the variability of demand reductions for time-based rates and incentive–based programs.

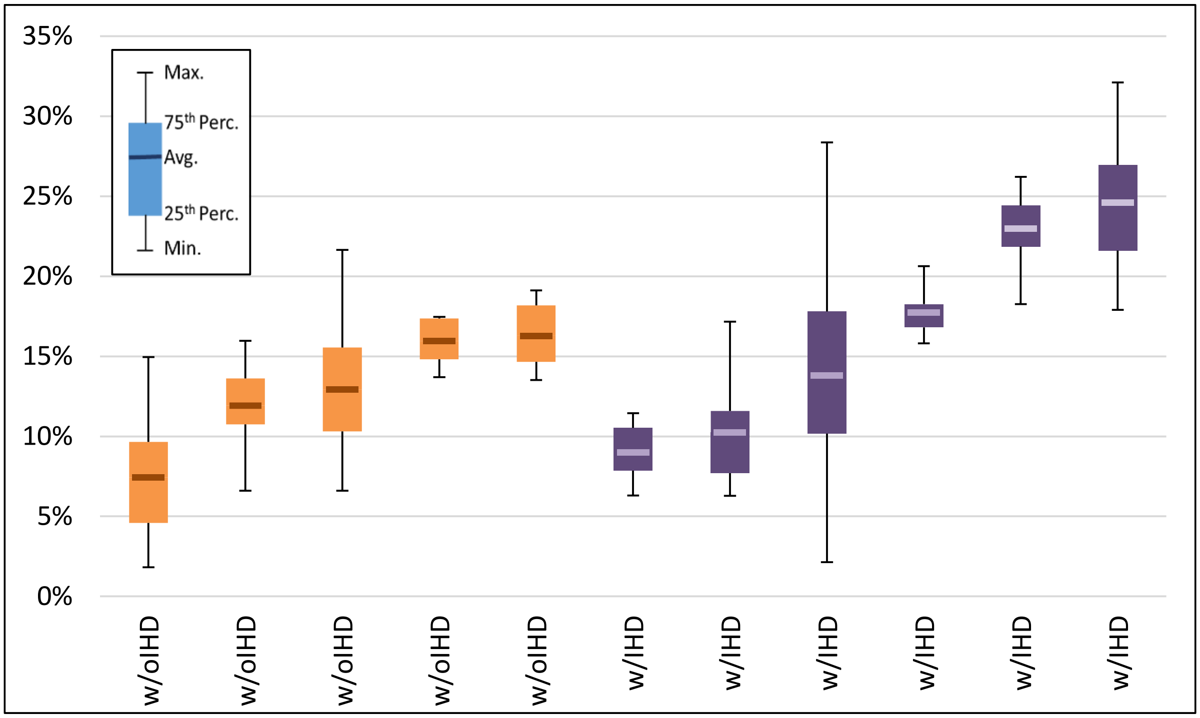

Figure 19. Variability of Per Customer Percent Demand Reductions for CPP Treatment Groups with and without IHDs by Treatment Group.

5.4 Cost Effectiveness

SMUD conducted cost-effectiveness analysis for a variety of rate offerings (TOU and CPP) with and without IHD offers. The benefit-cost ratios shown in Table 8 are consistent with the Total Resource Cost test as defined in the California Standard Practice Manual[42] and assume a 10-year time-frame that begins in 2018 and a nominal discount rate of 7.1%.

For both TOU and CPP, SMUD found higher benefit-cost ratios for scenarios without IHDs than for those with IHDs. While SMUD found that IHDs were correlated with slightly higher retention rates (1-4 percentage points) and boosted the magnitude of demand reductions by 2-4 percentage points, the costs of the devices were large enough to offset the majority of the additional benefits the IHDs generated. In the case of TOU rates, the offer of an IHD led to a result that was not cost-effective.

[42] CPUC, "California Standard Practice Manual – Economic Analysis of Demand-Side Programs and Projects" October, 2001.

Table 8. SMUD Cost Effectiveness Analysis Results for IHDs		
Recruitment Approach	**Scenario Offer**	**Benefit-Cost Ratio**
Opt-in	TOU, no IHD	1.19
	TOU, with IHD	0.74
	CPP, no IHD	2.05
	CPP, with IHD	1.30

6. Customer Automated Control Technologies

Customer automated control technologies are a category of devices that enable utilities and/or customers to automate responses to price or control signals for the purpose of altering the timing and level of electricity consumption. For residential customers, these technologies include PCTs and load controllers for air conditioners, water heaters, and swimming pool pumps. These types of technologies, especially load controllers, have been used for decades by utilities, and there is relatively more experience with their deployment than with newer customer information technologies. Several CBS utilities conducted evaluations of the efficacy of PCTs.

Conceptually, control technologies lower the transaction costs associated with responding to prices and critical peak events by making it easier for customers to reduce consumption and thereby increase the size of overall demand reductions. PCTs simplify the process of responding to critical events and/or higher priced periods by controlling air conditioner thermostat settings. However, as with IHDs, utility offers of free PCTs cause implementation costs to increase, so it is important to understand if the value of the additional demand reductions outweighs the costs of the technologies.

Because of the potential advantages several of the CBS utilities included evaluations of PCTs in their studies and addressed several key questions about their efficacy, including:

- What are some of the key lessons learned about PCTs in the implementation of time-based rates and incentive-based programs?
- To what extent do offers of PCTs affect enrollment and retention rates?
- To what extent do customers use offered PCTs, and what are the effects on the magnitude and variability of demand reductions?
- What are the costs and benefits of including PCTs and under what conditions and circumstances are the offers cost-effective?

6.1 Enrollment and Retention

Because of the way the CBS utilities designed the PCT treatments, it was not possible to assess the impacts on enrollment rates.[43] However, analysis of retention rates shows little or no impacts from

[43] Since many of the CBS utilities did not have accurate information about their residential customers' ownership of central air conditioning, it was only at the point when a customer responded to the offer to participate did the utility

PCT offers, as shown in Figures 20a and 20b, which runs counter to expectations that it would help enable customers to more easily adapt to and hence be more successful on these rates, making them more inclined to remain enrolled. The Figure 20a shows retention rates after the first year for 10 treatment groups with PCTs, compared with 33 treatment groups without PCTs. These data reflect results for 9 CBS utilities. While the overall results vary somewhat, the average retention rates with and without PCTs are about the same: approximately 90% for those with PCTs, and about 89% for those without. Likewise, Figure 20b shows retention rates after the second year for 6 treatment groups with PCTs, compared with 28 treatment groups without PCTs. These data reflect results for 5 CBS utilities and exhibit a similar pattern of retention as in year 1: 91% with PCTs and 91% without PCTs.

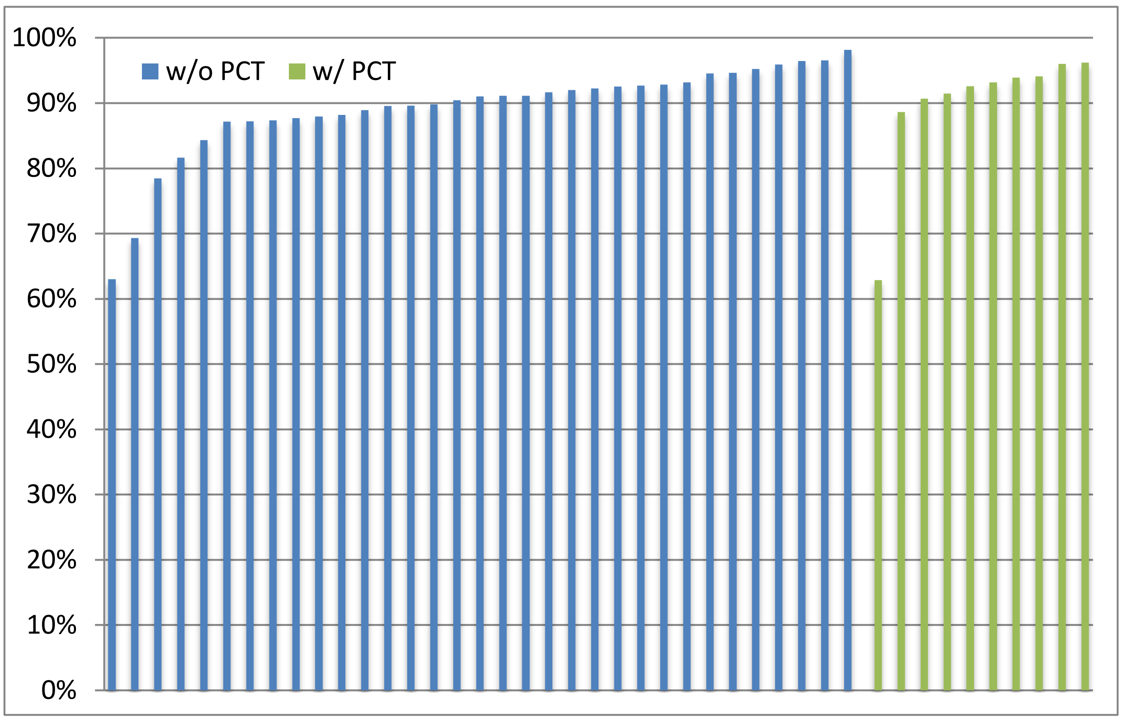

Figure 20a. Effects of PCTs on Retention Rates after the First Year of the Study by Treatment Group.

determine eligibility to participate in a PCT treatment. Any enrollment rate concerning PCTs resulting from such a recruitment process would be adversely affected by this lack of information as ineligible customers would be included in the population of customers recruited to participate in the study.

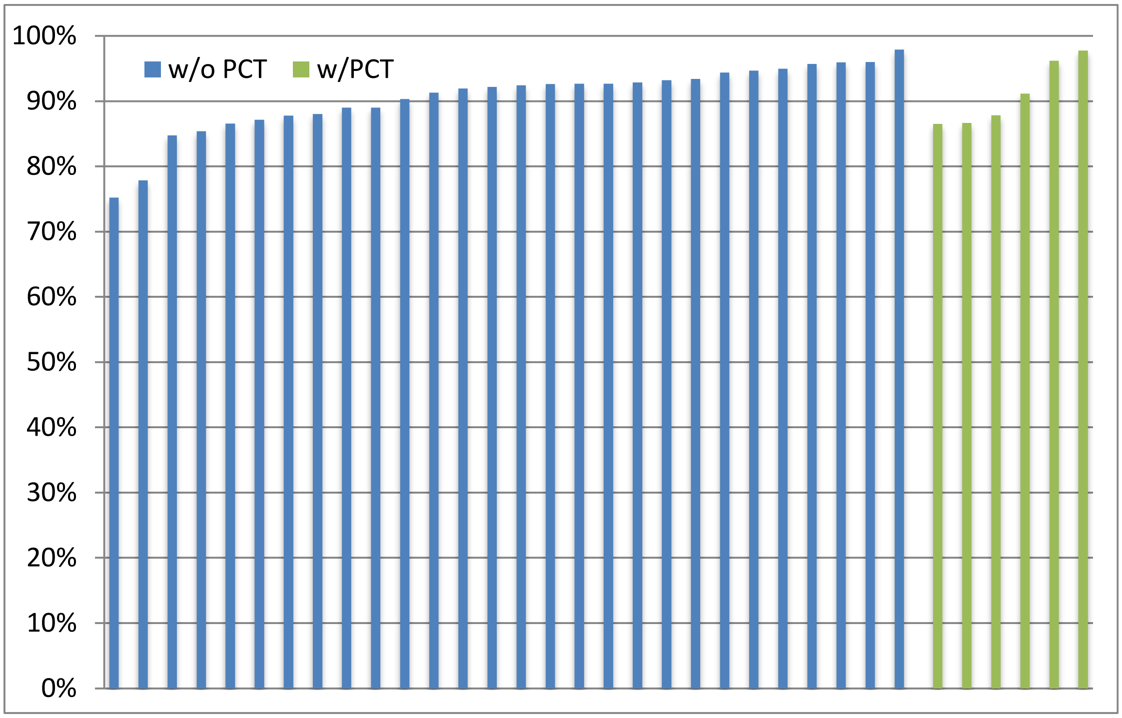

Figure 20b. Effects of PCTs on Retention Rates after the Second Year of the Study by Treatment Group.

6.2 Lessons Learned

PCTs are typically provided to customers with the understanding that utilities, not customers, will be the ones initially controlling thermostat set points during critical events. However, to promote acceptance, customers are typically given the ability to override utility controls if they are unhappy with the indoor comfort levels that result during critical peak events.

This approach relies on the theory of the default effect and is similar in concept to the application of that theory discussed in Chapter 3. In the case of PCTs, it is expected that customers, if left on their own, would be less likely to set the thermostat as high during critical events as the utility's control strategy. If the utility is able to pre-program the thermostat instead of the customer, the default bias suggests customers will be less likely to override the utility's higher thermostat control settings during events thereby maximizing the level of response.

The CBS utilities found that during the planning phases of the studies, market surveys and focus groups showed customers reluctant to have utilities in control of the PCTs during events and strongly preferred opting-in and retaining PCT control for themselves. However, once the devices were installed, and customers gained familiarity, most relaxed their concerns and allowed the utilities to control the PCTs during events after all. This lesson-learned suggests that utilities need to better address customers' initial concerns about control as these concerns are alleviated once experience is gained with the utility's control strategy for the PCTs. By doing so, it is likely more customers will be accepting of a utility-controlled PCT and thus the utility may be able to achieve higher aggregate demand reductions during all critical events.

6.3 Demand Reductions

While PCT offers did not appear to affect retention rates much, several of the CBS utilities found that demand reductions were higher for customers with PCTs than for those without. Figure 21 shows results for 8 CBS utilities encompassing 70 treatment groups and covers demand reductions for critical peak events involving CPP and CPR. The estimated demand reductions for customers with PCTs ranged from about 22% to 45%; while the estimated demand reductions for customers without PCTs ranged from about -1% to 40%.

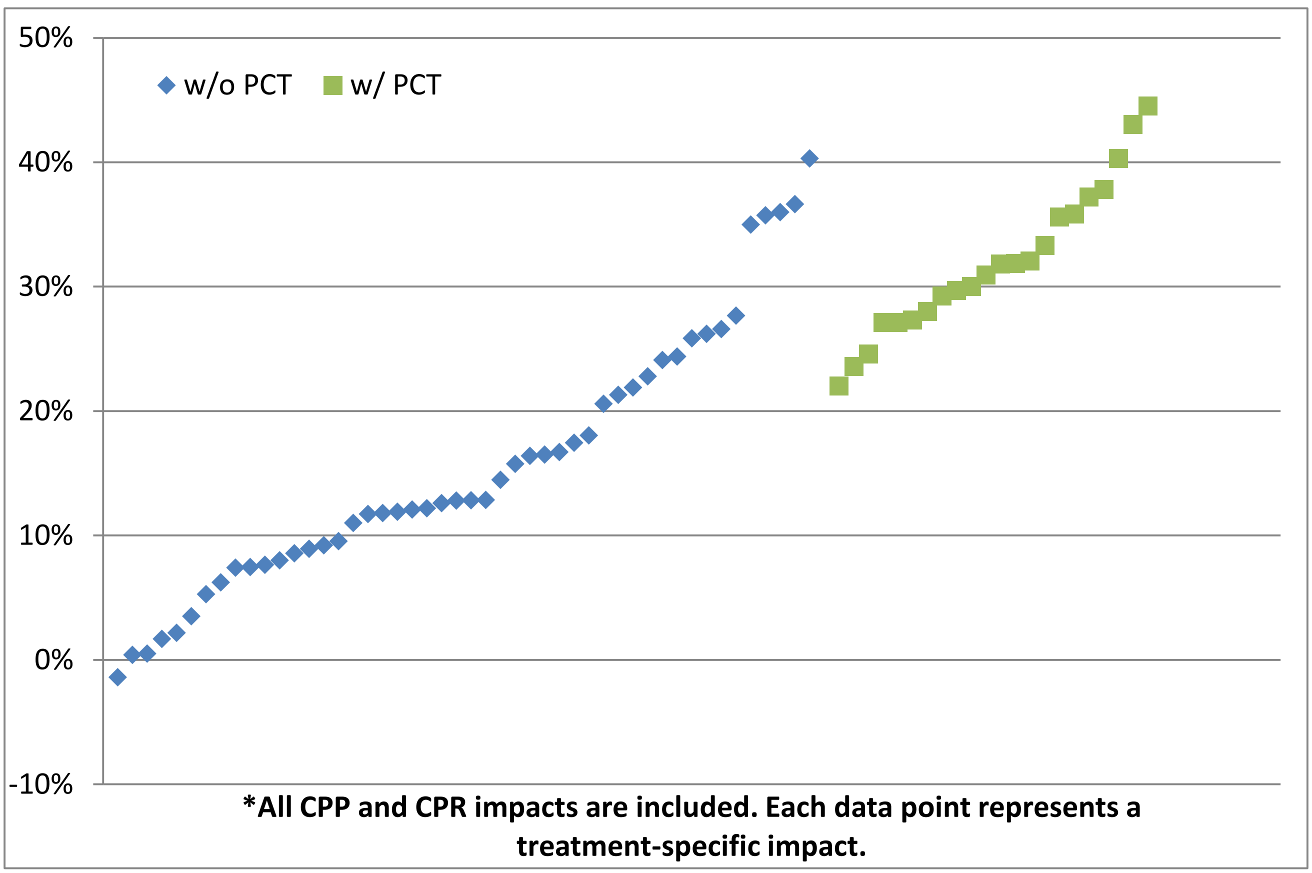

Figure 21. Average Percent Demand Reductions for Critical Event Days with and without PCTs by Treatment Group.

While PCTs generally increased the average level of demand reductions, if the devices also led to less variability in demand reductions, then the value would be increased further because of greater confidence by grid operators in the certainty of the resource. Figure 22 shows results from 3 CBS utilities and 19 CPP treatment groups. The results are generally inconclusive as certain PCT treatment groups showed less variability, while others showed greater variability. However, a separate analysis of average demand reductions for the critical peak events, and using NYISO's performance factor methodology described in Chapter 4, shows that grid operators would derate the average demand reduction 7% for CPP customers with PCTs, and 10% for CPP customers without PCTs. These results suggest that PCTs do reduce the level of variability of demand reductions associated with rates and programs, but only modestly so.

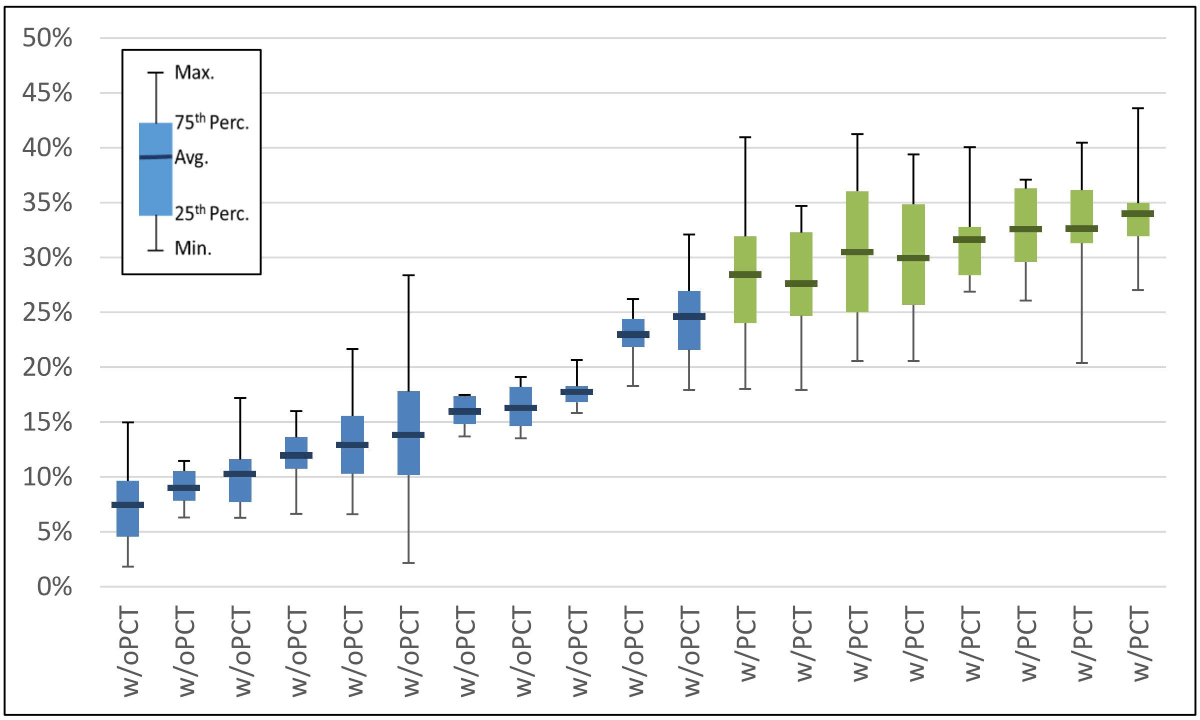

Figure 22. Variability of Per Customer Percent Demand Reductions for CPP Treatment Groups with and without PCTs by Treatment Group.

Utilities and other stakeholders are also interested in assessing the extent of anticipatory or remediation behaviors with respect to critical peak events (e.g., "pre-cooling" and "snap-back", respectively). The CBS evaluation results so far suggest there is not a clear pattern of pre-event behavioral changes on average; although these effects were observed in at least one of the individual studies. In contrast, after events, it does appear that customers with PCTs increased their electricity demand on average. This is consistent with prior studies, and is likely the result of strategies customers employ to raise thermostat set points during critical peak events and then lower the set points when the events are over.

Measuring the magnitude of this remediation (e.g., “snap-back”) effect, and the conditions under which it occurs, become increasingly important as participation in these types of demand response opportunities grows. At scale, these shifts in the timing of the maximum demand (later in the afternoon and early evening), and the need to bring on new power supplies to meet the increase in demand, will need to be forecasted accurately and subsequently managed by system operators.

6.4 Cost Effectiveness

OG&E conducted cost-effectiveness analysis of a broad roll out of its VPP rate offering which included offers of PCTs at no cost to participating customers. Shown in Table 9, the results use the standard cost effectiveness tests originally established by the California Public Utilities Commission in its Standard Practice Manual.[44] The table shows positive benefit-cost ratios in all of the standard tests. OG&E did not estimate benefit-cost ratios for simulated cases of the program without PCTs. The Total Resource Cost test results are comparable to the SMUD benefit-cost ratios for IHDs presented in Table 9. Based on these findings, OG&E filed a request, which was approved by the Oklahoma Corporation Commission, to roll-out the VPP rate offering with free PCTs under an opt-in recruitment approach with the goal of enrolling 120,000 (~20%) of its residential and small commercial customers across its service territory within 3 years.

[44] CPUC, “California Standard Practice Manual – Economic Analysis of Demand-Side Programs and Projects” October, 2001.

Table 9. OG&E Cost Effectiveness Analysis Results for PCTs[45]	
Benefit-Cost Ratios	
Participant Test	1.50
Rate Impact Measure Test	1.01
Total Resource Cost Test	1.18
Societal Test	1.18
Program Administrator Cost Test	1.11

[45] OCC (2012). In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Approving its 2013 Demand Portfolio and Authorizing Recovery of the Costs of the Demand Programs through the Demand Program Rider. Oklahoma Corporation Commission. Cause No. PUD 201200134. Order No. 605737. Attachment B, Page 5 of 18, Table 1, Row “Smart Hours Program”.

7. Customer Response to Price

Economic theory suggests that people are generally willing to buy larger quantities of a good as its price goes down. Conversely, as the price increases, people are expected to buy less of that same good. This basic relationship can be used to explain what is expected to happen when a TOU rate is introduced: electricity consumption should be reduced in the peak period when the price of electricity is raised while electricity consumption should be increased in the off-peak period(s) when the price is dropped.

A number of CBS utilities were interested in better understanding how such TOU rates could more broadly affect electricity usage during the highest priced hours of each day (i.e., peak period). To this end, these CBS utilities implemented TOU rates as part of their studies.[46] A subset of them also overlaid either a CPP or CPR rate onto the TOU rate in order to assess how customers would alter their peak period demand reduction in response to the higher event price. In general, the CBS utilities were interested in answering several key questions about their efficacy, including:

- What are the magnitude of peak period demand reductions?
- What are the effects on the magnitude of peak period demand reductions from the peak to off-peak price ratio?[47]
- What are the effects on the magnitude of peak period demand reductions from the existence of a PCT?
- What are the magnitude of event demand reductions?
- What are the effects on the magnitude of event demand reductions from the existence of a PCT?

[46] Because of the overlay nature of CPP and VPP, we focused on customer response estimates on non-event days. For OG&E's Variable Peak Pricing treatments, this meant we report customer response estimates on days when the rate was set at any level except Critical. Since VEC did not separately estimate customer response on days when the price threshold was not exceeded (i.e., standard TOU peak price was in effect) vs. when it was exceeded (i.e., variable peak price was in effect), we report the customer response estimate for all days.

[47] Since so few of the CBS utilities' reported elasticity estimates from their studies, which would be a more rigorous and direct way of assessing how changes in the price of electricity affects electricity consumption, the most comprehensive way of reporting peak period demand reductions available was to segment them by the peak to off-peak price ratio.

7.1 Peak Period Demand Reductions

The CBS utilities had a varied experience with customer response during the TOU rate's peak period. Figure 23 shows results for 5 CBS utilities encompassing 67 treatment groups and covers peak period demand reductions. The estimated demand reductions ranged from a low of -1% (i.e., load increased for the average customer in this TOU treatment by 1%) to a high of 29%, with an average of 15%.

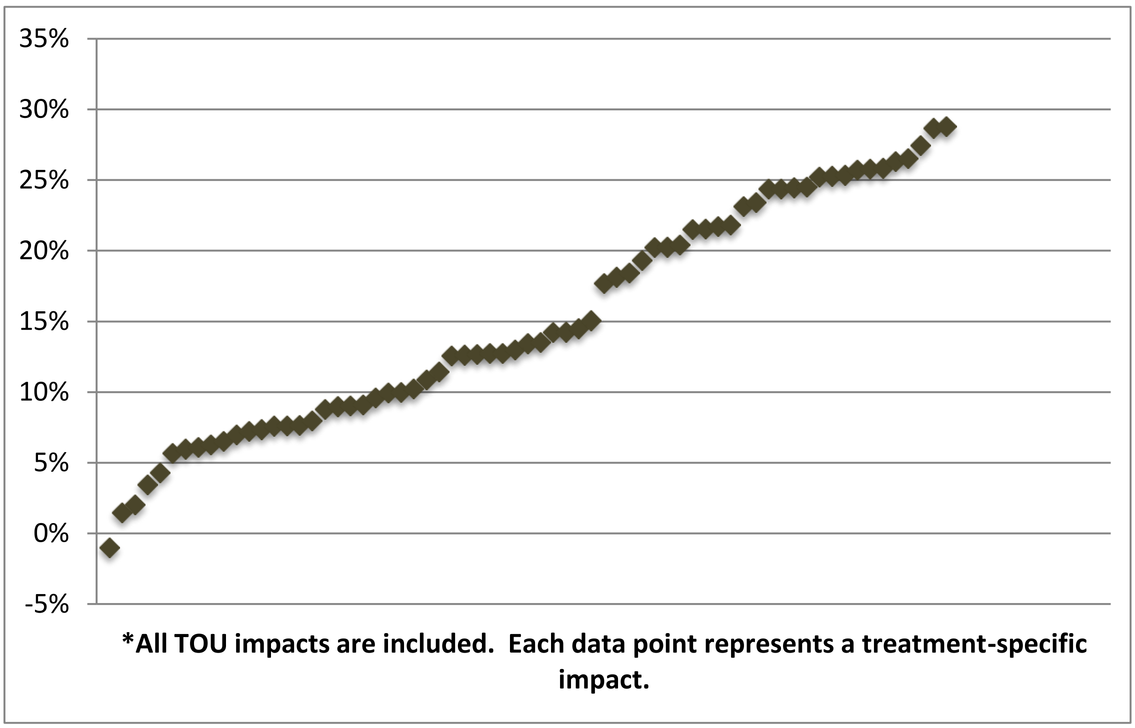

Figure 23. Average Percent Peak Period Demand Reductions by Treatment Group.

To better understand if differences in the TOU rate affected the level of peak period demand reduction, the estimated peak period demand reductions were grouped by their peak to off-peak price ratio:[48]

- Less than 2:1 price ratio;

[48] In order to compare across the different treatments, it is common to normalize the peak period price by the off-peak period price. The economic theory should still hold even if what is now being compared are price ratios and not just the price levels.

- 2:1-3:1 price ratio; and
- Greater than 4:1 price ratio.

Figure 24 shows the same average peak period demand reductions for the 67 separate TOU treatments organized by these three price ratio groupings. At the mean of each grouping, customers responded on average the least to the lowest price ratio (6% for a price ratio less than 2:1) and on average the most to the highest price ratio (18% for a price ratio greater than 4:1). However, the range of peak period demand reductions varied substantially within each price ratio grouping, at some points overlapping those from other price ratio groupings. This suggests something in addition to price may be driving differences in the observed response level.

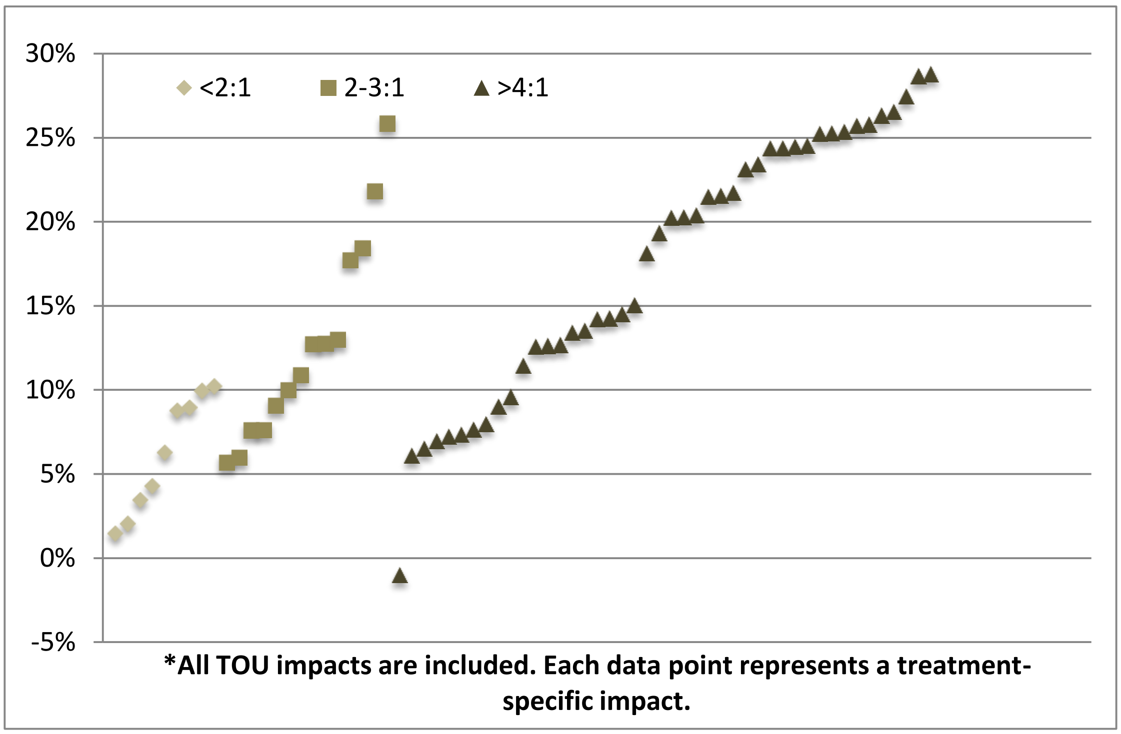

Figure 24. Average Percent Peak Period Demand Reductions by Treatment Group and Price Ratio Grouping.

Several CBS utilities included the offer of a PCT with their TOU rates. The peak period demand reductions can be further segmented by the existence or absence of a PCT. Figure 25 shows the peak period demand reductions for all 67 TOU treatments organized by price ratio grouping and existence of a PCT. At the lowest price ratios (i.e., those less than 2:1), a PCT seems to make little difference in the level of peak period demand reductions. However, as the price ratio increases to more moderate levels (i.e., between 2:1 and 3:1), we see the existence of a PCT makes a considerable difference as customers exhibit dramatically larger peak period load reductions when the control technology is available (average of 21% across all treatments) relative to when it is absent (average of 10% across all treatments). When the price ratio is at its highest (i.e., greater than 4:1), the role of a PCT in driving higher peak period demand reductions is not quite as clear. Although the average peak period demand reduction for treatments with PCTs is considerably higher than the average for treatments without PCTs (23% vs. 15%), there is considerable variability across treatments both with and without PCTs.

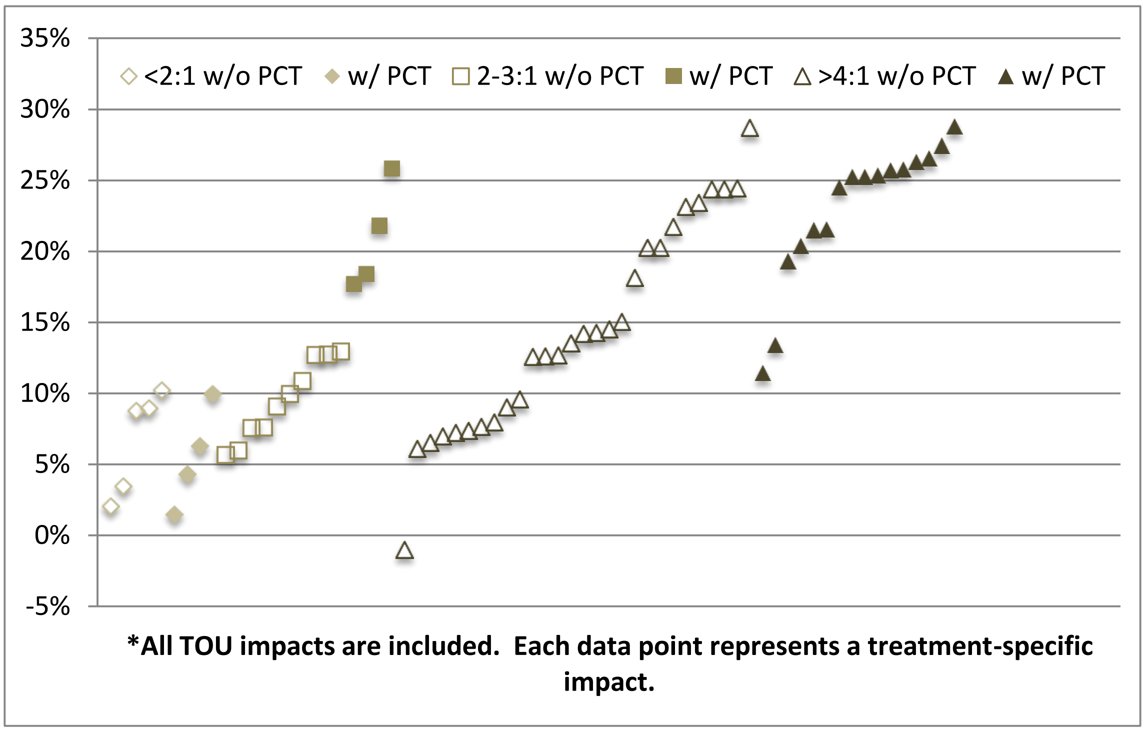

Figure 25. Average Percent Peak Period Demand Reductions by Treatment Group, Price Ratio Grouping and PCT.

7.3 Event Demand Reductions due to CPP/CPR

Four of the CBS utilities chose to overlay a CPP/CPR rate on the TOU rate to gauge the level of additional peak period demand reduction they could achieve during events relative to non-event days. Figure 26 shows results for 4 CBS utilities encompassing 23 treatment groups and covers event-only peak demand reductions. The average event peak demand reduction was 27% over all of the treatments, but ranged from 9% to 40%. This stands in contrast to non-event day peak period demand reductions, as described in Figure 23, where the average demand reduction over all treatments was 15%, with a range of -1% to 29%.

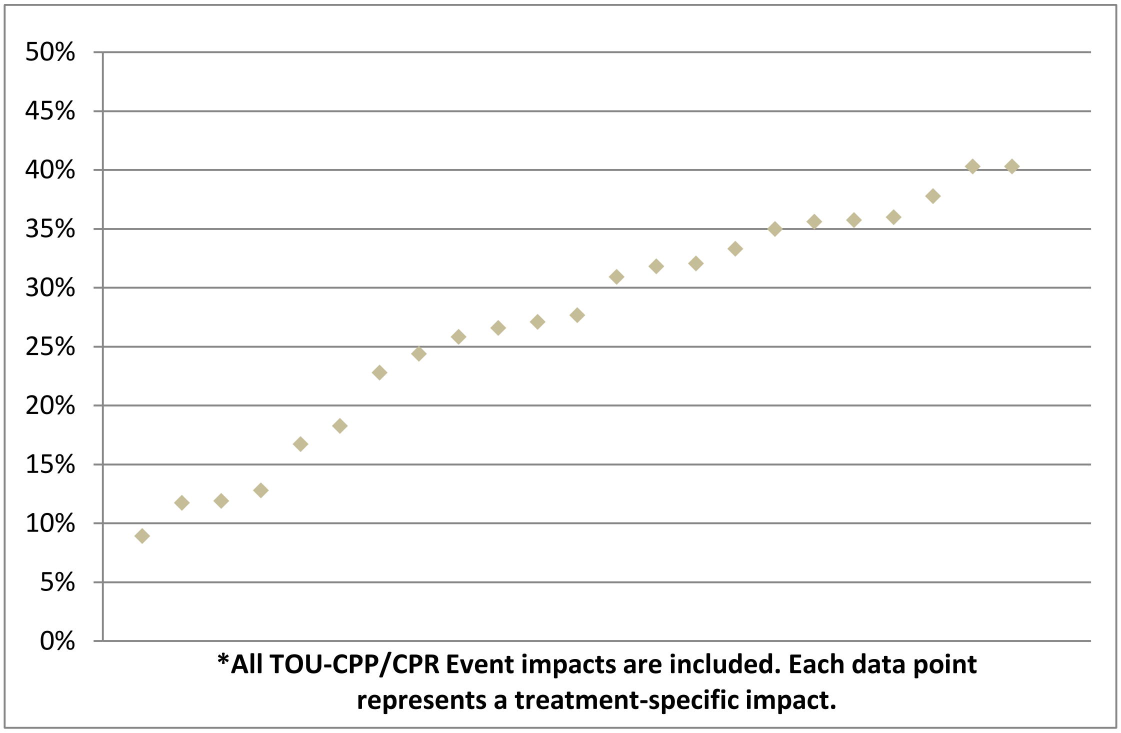

Figure 26. Average Percent Event Demand Reductions by Treatment Group.

Several of the CBS utilities also paired a PCT with their TOU CPP/CPR rate treatment. Figure 27 shows the same set of event demand reductions as portrayed in Figure 26, but this time organized by whether or not the treatment included a PCT. Consistent with the results presented in other chapters of this report, the existence of a PCT makes a difference to the response during events: 34% average demand reduction over all treatments when a PCT was present vs. 24% in the absence of a PCT.

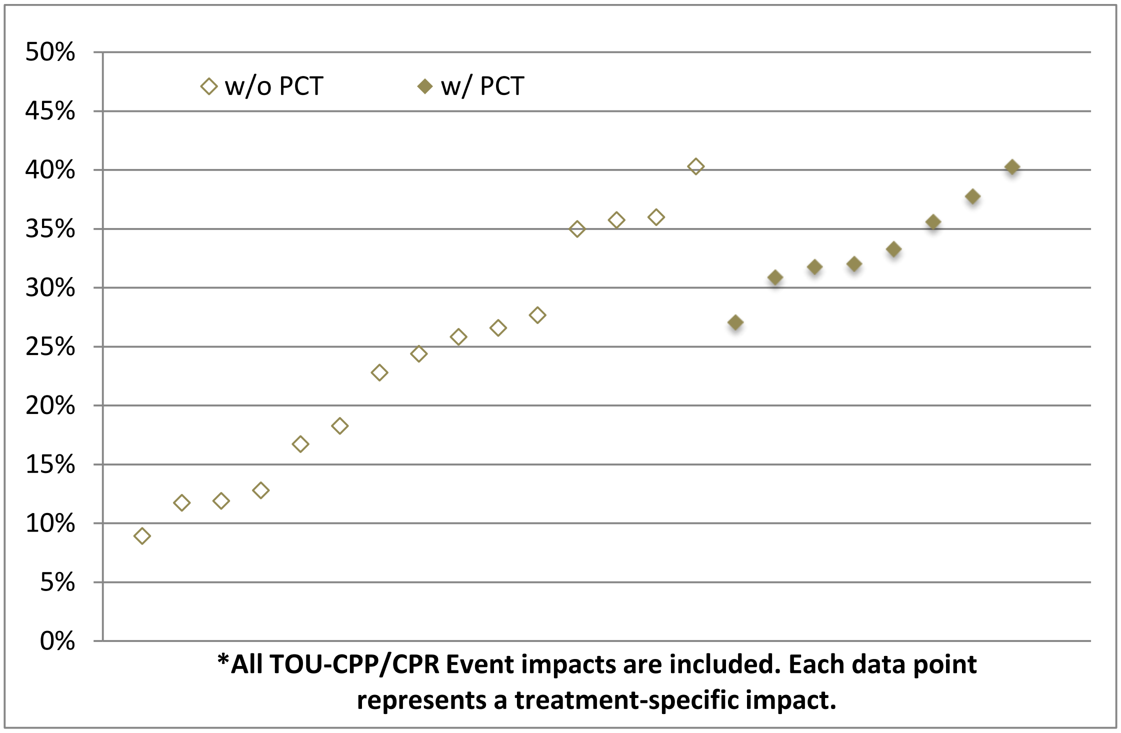

Figure 27. Average Percent Event Demand Reductions by Treatment Group with and without PCTs.

8. Conclusions

The CBS program effort produced a tremendous amount of novel insights about customer preferences for and responses to other time-based rate designs as well as information and control technology that are, at present, supportable by many regulators, policymakers and utilities.

8.1 Major Findings

Results from the CBS utilities can be grouped into five general areas:

(1) Recruitment approaches – effects of opt-in and opt-out;
(2) Pricing versus rebates – effects of CPP and CPR;
(3) Customer information technologies – effects of IHDs;
(4) Customer control technologies – effects of PCTs; and
(5) Customer response to prices – effects of TOU.

Table 10 summarizes major findings in these five areas and are each discussed in greater detail below.

Table 10. Summary of Major Findings

Area	Major Findings – Demand Reductions & Enrollment/Retention Rates
Recruitment Approaches – Opt-in & Opt-out	• Opt-out enrollment rates were about 3.5 times higher than they were for opt-in (93% vs. 15%). • Retention rates for opt-out recruitment approaches (85.5% in year 1 and 88.5% in year 2) were about the same as they were for opt-in (89.7% in year 1 and 91.0% in year 2). • Peak period demand reductions for SMUD's opt-in TOU customers were about twice (13% in year 1 and 11% in year 2) as large as they were for opt-out customers (6% in year 1 and year 2). • Peak period demand reductions for SMUD's opt-in CPP customers were about 50% higher (24% in year 1 and 22% in year 2) than they were for opt-out customers (12% in year 1 and 14% in year 2). • SMUD's opt-out offers were more cost-effective for the utility than their opt-in offers in all cases. • Roughly two-thirds of those who were defaulted onto SMUD's TOU rates were expected to see bill impacts of +/- $20 for the entire 4 summer months the rates were in effect. • Based on survey responses, a majority of those defaulted onto SMUD's TOU rate were satisfied with the rate, regardless of the level of bill savings achieved, but those who saw the largest bill increases were generally less interested in continuing with the rate after the study ended.

Pricing Versus Rebates – CPP & CPR	• While opt-in enrollment rates for GMP were about the same for CPP (34%) and CPR (35%), retention rates were somewhat lower for CPP (80%) than they were for CPR (89%). • Average peak demand reductions for CPP (20%) were about 3.5 higher than they were for CPR (6%), but when automated controls (PCTs) were provided, they were about 30% larger (35% for CPP and 26% for CPR).
Customer Information Technologies - IHDs	• Enrollment and retention rates were generally unaffected by offers of IHDs. • SMUD's opt-in CPP customers with IHDs (26% in year 1 and 24% in year 2) had somewhat higher peak demand reductions than those without IHDs (22% in year 1 and 21% in year 2), but these differences can be explained by pre-treatment differences between the two groups. • SMUD's opt-in TOU customers with IHDs (13% in year 1 and 11% in year 2) had somewhat higher peak demand reductions than those without IHDs (10% in year 1 and 9% in year 2), but these differences can be explained by pre-treatment differences between the two groups. • SMUD's offerings without IHDs were more cost-effective for the utility in all cases than those with IHDs.
Customer Control Technologies - PCTs	• Enrollment and retention rates were generally unaffected by offers of PCTs. • Peak demand reductions are generally higher for CPP and CPR customer with PCTs (22% to 45%) than they were for customers without PCTs (-1% to 40%). • OG&E rate offers with PCTs were more cost-effective for the utility than those without PCTs.
Customer Response to Price - TOU	• Peak period demand reductions were far less, on average, for the lowest peak to off-peak price ratios (6% for treatments with a peak to off-peak price ratio less than 2:1) than for the highest price ratios (18% for treatments with a peak to off-peak price ratio greater than 4:1). • When a CPP/CPR was overlaid on the TOU rate, the average event peak demand reduction rose to 27% when averaged over all of the treatments • When PCTs were available, the differences in average peak period demand reductions were only affected at peak to off-peak price ratios in excess of 2:1 (21% vs. 10% for price ratios between 2:1 and 3:1 and 23% vs. 15% for price ratios in excess of 4:1).

Recruitment Approaches – Effects of Opt-in and Opt-out

Results from the CBS utilities show that enrollment rates were much higher and peak demand reductions were lower under opt-out recruitment approaches, but that retention rates were about the same for both. Because of these results, there were overall benefit-cost advantages to using opt-out approaches over opt-in. When broken down further into customer sub-populations, based on those who were assumed to have actively made a choice to accept SMUD's default offer of a TOU rate (Always Takers) and those who simply didn't eschew it (Complacents), a subset of the Complacents seemed much less engaged, attentive and informed than the other study participants.

However, extending the results to apply to SMUD's entire residential population, this suggests that it is not the entirety of the residential class or even the full share of Complacents who are at-risk of being made worse off from a transition to default TOU, but rather a subset of the latter. Most importantly, these results suggest that there is a sizable share of the residential customer class at SMUD that was seemingly better off on a default TOU rate relative to the voluntary recruitment approach.

Prices versus Rebates – Effects of CPP and CPR

Results from the CBS utilities show that retention rates were higher for CPR than for CPP and demand reductions achieved without enabling control technology were generally higher for CPP than for CPR. However, when PCTs were available as an automated control strategy, the differences in peak demand reductions between CPP and CPR were largely eliminated.

Customer Information Technologies – Effects of IHDs

Results from the CBS utilities show that free IHD offers did not make a substantial difference for enrollment and retention rates. Although SMUD's peak demand reduction estimates were larger with IHDs, this result can be attributed to pre-treatment differences between the two groups so there was not a measured IHD effect on reductions of peak demand. As a result, cost-benefit ratios of rate offerings were lower when they included offers of free IHDs. In addition, many of the CBS utilities reported significant challenges with this relatively new technology. Problems included getting the IHDs to function properly and in one case the manufacturer decided to halt production and stop support.

Customer Control Technologies – Effects of PCTs

Results from the CBS utilities show that free PCT offers did not make a major difference for enrollment and retention, but that peak demand reductions were substantially higher. Unlike with IHDs, cost-benefit ratios for PCT offers were favorable. In response, one utility (OG&E) decided to roll-out a time-based rate with an offer of a free PCT to its entire residential customer class with a recruitment goal of 120,000 customers within three years.

Customer Response to Price – Effects of TOU

Results from the CBS utilities show that customers exhibited far less peak period demand reductions, on average, to the lowest TOU price ratios (6% for treatments with a peak to off-peak price ratio less than 2:1) than to the highest TOU price ratio (18% for treatments with a peak to off-peak price ratio greater than 4:1). However, when PCTs were available as an automated control strategy, the differences in average peak period demand reductions were substantively affected at peak to off-peak price ratios in excess of 2:1 (21% vs. 10% for price ratios between 2:1 and 3:1 and 23% vs. 15% for price ratios in excess of 4:1). When CPP/CPR was overlaid on the TOU rate, the average event peak demand reduction was 27% when averaged over all of the treatments. However, when PCTs were available, the average event peak demand reduction was 34% vs. 24% when such automated control technology was not available.

8.2 Concluding Remarks

Rigorous experimental methods were applied in these consumer behavior studies with the hopes that more credible and precise load impact estimates would help resolve some of the outstanding issues hindering broader industry adoption of time-based rates for residential customers. Since none of the CBS utilities had any experience with such experimental methods, each CBS utility was provided with a small team of industry experts who provided technical assistance in the design, implementation and evaluation of each study. Besides direct engagement with each CBS utility, these Technical Advisory Groups (TAGs) also produced a library of guidance documents for the CBS utilities (which are publicly available on smartgrid.gov) on such diverse topics as study plan documentation, experimental design, rate and non-rate treatments, and evaluation techniques. With the help of these TAGs and the reference material they produced, many of the concerns initially raised about the application of experimental methods (e.g., withholding or deferring exposure to the rate after a customer had agreed to participate in the study would create customer relations problems) did not materialize. In addition, TAGs helped the utilities more narrowly focus their studies on a core set of objectives that would more readily and directly contribute to deliberations by each of the CBS utilities after the study about what to move forward with. As such, this consumer behavior study effort produced a wealth of contributory results on a number of critical issues the electric power industry was seeking information on, as described above.

Both utilities and participating customers learned a tremendous amount about themselves and their capabilities through these studies. Although not an explicit objective of the consumer behavior studies, their success hinged on the ability of the CBS utilities to effectively engage customers – many of whom had very limited experience in this arena. As such, several CBS utilities recognized the importance of performing market research during the study design phase to ensure marketing material was as effective as possible to engage customers as participants in the studies. The most successful CBS utilities continued that engagement not just during recruitment but throughout the study period itself, which included the creation of a plethora of different materials using a number of different mediums (e.g., monthly newsletters, social media campaigns of tips and tricks) that constantly sought to keep customers engaged in the study. Such efforts seemed to be quite successful, as the vast majority of customers who started the studies also completed them, expressed a high level of satisfaction in their experiences with these new rates and to a lesser extent with the new technologies, and continued taking service under the rate after the study ended, provided such opportunities were available.

It was hoped that this success would catalyze change in the electric industry both for those directly participating in these consumer behavior studies but also more broadly speaking for those totally unaffiliated with it. Three of the ten CBS utilities allowed participants to continue taking service under the rates after their study was completed. Four of the ten CBS utilities chose to extend an offer of the rates tested in their study to the broader population of residential customers. Specifically, OG&E has reached ~20% penetration of its residential class on the Variable Peak Pricing rate tested in its CBS after a little more than three years of marketing it. SMUD chose to make the TOU rate it tested the default for all of its residential customers, starting in 2018. More broadly, the California Public Utility Commission ordered all of the state's investor-owned utilities to make TOU the default for residential customers, citing heavily the very positive results SMUD achieved as grounds for this decision. DOE hopes the experiences and results from the CBS effort which have been published to date, as well as those yet to come, can help other utilities and regulators more aggressively pursue the application of time-based rates for residential customers.

Appendix – Summary of CBS Time-Based Rate Offerings[49]

KEY

CPP = Critical Peak Pricing
CPR = Critical Peak Rebate
TOU = Time of Use
IBR = Increasing Block Rate
Flat = Constant Price

All prices have been rounded to 3 decimal places.

GMP

Utility	Customer	Rate Type	Off Peak ($/kWh)	Critical Peak ($/kWh)
Green Mountain Power	Treatment	CPP	0.144	0.60
	Treatment	CPR	0.148	-0.60
	Control	Flat	0.148	0.148

DTE

Utility	Customer	Rate Type	Off Peak ($/kWh)	Mid Peak ($/kWh)	Peak ($/kWh)	Critical Peak ($/kWh)
Detroit Edison	Treatment	TOU+CPP	0.04	0.07	0.12	1.00
	Control	IBR	0.069/kWh for the first 17 kWh per day; 0.083/kWh for excess consumption over 17 kWh per day.			

FirstEnergy-CEIC

Utility	Customer	Rate Type	Off Peak ($/kWh)	Critical Peak ($/kWh)
FirstEnergy	Treatment	CPR	0.03	-0.40
	Control	Flat	0.03	0.30

[49] This summary of rate offerings are for the six CBS utilities that had produced initial or final evaluation reports at the time this report was written.

MMLD

Utility	Customer	Rate Type	Off Peak ($/kWh)	Critical Peak ($/kWh)
Marblehead Municipal Light District	Treatment	CPP	0.09	1.05
	Control	Flat	0.143	0.143

OG&E

Utility	Customer	Rate Type	Off Peak ($/kWh)	Variable Peak 1 ($/kWh)	Variable Peak 2 ($/kWh)	Variable Peak 3 ($/kWh)	Variable Peak 4 ($/kWh)	Critical Peak ($/kWh)
Oklahoma Gas & Electric	Treatment	TOU+CPP	0.042	0.23	0.23	0.23	0.23	0.46
	Treatment	VPP+CPP	0.045	0.045	0.113	0.23	0.46	0.46
	Control	IBR	0.084/kWh for consumption up to 1,400 kWh; 0.097/kWh for consumption beyond 1,400kWh					

SMUD

Utility	Customer	Rate Type	Peak ($/kWh)	Critical Peak ($/kWh)	Tier 1 ($/kWh) 0-700kWh	Tier 2 ($/kWh) 701-1425kWh	Tier 3 ($/kWh) 1426+kWh
Sacramento Municipal Utility District	Treatment	CPP	n/a	0.75	0.085	0.167	0.167
		TOU	0.27	n/a	0.085	0.166	0.166
		TOU+CPP	0.27	0.75	0.072	0.141	0.141
	Control	IBR	n/a	n/a	0.102	0.183	0.183
	Treatment EAPR	CPP	n/a	0.50	0.055	0.117	0.167
		TOU	0.20	n/a	0.055	0.116	0.166
		TOU+CPP	0.20	0.50	0.049	0.099	0.141
	Control EAPR	IBR	n/a	n/a	0.066	0.128	0.183

*EAPR stands for "Energy Assistance Program Rate", which is a program that provides discounted electricity rates to low-income residents.

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Advanced Metering Infrastructure Technology

Limiting Non-Technical Distribution Losses In The Future

1016049

Advanced Metering Infrastructure Technology

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Technical Update, December 2008

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This report describes research sponsored by EPRI.

This publication is a corporate document that should be cited in the literature in the following manner:

Advanced Metering Infrastructure Technology: Limiting Non-Technical Distribution Losses In the Future. EPRI, Palo Alto, CA: 2008. 1016049.

PRODUCT DESCRIPTION

Revenue security is a major concern for utilities. Theft of electric service in the United States is widespread. In 2006, the revenue estimate for non-technical losses was $6.5 billion. Non-technical losses are associated with unidentified and uncollected revenue from pilferage, tampering with meters, defective meters, and errors in meter reading. In this report, revenue security describes the use of advanced metering infrastructure (AMI) technology to minimize non-technical losses.

Results and Findings

The report defines revenue security as securing revenue that is due to the distribution utilities from the delivery of electricity to end-users. The report distinguishes between revenue losses caused by technical and non-technical factors, with a primary focus on the latter. Integrated with meter data management system (MDMS) technology—software that accepts, stores, and forwards AMI-collected data to utility systems such as billing—AMI significantly improves a utility's ability to monitor customers' electric meters and detect both intentional electricity bypasses and unintentional errors (for example, billing and customer service problems encountered by traditional manual meter-reading operations). The report describes AMI technologies in detail, from enabling hardware and software to transitioning from traditional systems to installation and implementation. The transition from meter reader to meter revenue protection agent also is discussed. A case study concludes the report by describing how PPL Electric Utilities of Pennsylvania successfully deployed and implemented AMR/AMI throughout its entire service territory (1,353,024 meters as of 2006).

Challenges and Objective(s)

Revenue security involves securing revenue that is due distribution utilities from delivery of electricity to end-users. It includes both reducing losses and collecting revenue associated with the electricity delivered. Non-technical distribution losses occur at the point of delivery and measurement. Minimizing non-technical losses increases the amount of electricity that is delivered, measured, and billed. This is the challenge to revenue security.

Applications, Values, and Use

AMI solutions involve the retrieval of daily or hourly consumption readings and use database information (comparisons with prior once-a-month readings) to identify locations where theft might be taking place. After AMI installation, utilities may uncover a substantial number of previously unknown sources of diversion. By reading meters frequently, AMI also identifies bad meters more quickly and reduces the need for estimating unmetered energy use. AMI's improved meter-reading accuracy also results in improved billing accuracy, fewer customer complaints, reduced call center traffic, and improved customer service.

EPRI Perspective

AMI systems provide new and innovative tools for revenue assurance. With comprehensive AMI/MDMS and vigorous meter revenue protection programs, AMI will have a positive impact on minimizing non-technical losses due to theft. In areas other than theft, AMI offers additional advantages, such as using MDMS features in customer service to respond more quickly and accurately to high-bill inquiries.

Approach

The project team gathered information for this report from a variety of sources, including government surveys, industry reports, Internet searches, utilities, and vendors. When determining the impact of non-technical losses on revenue, the team examined aggregate measurements of revenue and distribution losses from reliable government statistical sources and applied ratios from various industry surveys and reports.

Keywords

Advanced metering infrastructure
Revenue assurance
Meter data management systems
Non-technical losses
Meter tampering
Electricity theft

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CHAPTER 1

Revenue Security

Revenue security may be viewed as securing revenue that is due to the distribution utilities from the delivery of electricity to end-users. It includes both the reduction of losses and the collection of the revenue that are associated with the electricity delivered. The activities related to revenue security are oftentimes called "revenue protection" or, more recently, "revenue assurance."[1]

Utility revenue is a function of electricity delivered to end-users (kWh) and the billing rate ($/kWh).

This is expressed in the following formula:

$$R = E_d * r$$

Where:

$R =$ Revenue ($)
$E_d =$ Energy delivered (kWh)
$r =$ rate ($/kWh)

The electricity delivered to end-users is generation minus losses in generation, transmission, and distribution. Distribution losses are divided into two components, technical and non-technical.

This is expressed in the following formula:

$$G - (L_g + L_t + L_{d+} L_n) = E_d$$

Where:

$G =$ Gross generation
$L_g =$ Generation losses
$L_t =$ Technical losses – transmission
$L_d =$ Technical losses – distribution
$L_n =$ Non-technical losses
$E_d =$ Energy delivered

Transmission losses and technical distribution losses relate to the physical characteristics and functioning of the electrical system itself. Non-technical distribution losses occur at the point of

---

[1] Revenue assurance includes theft detection and follow-up, metering malfunctions, billing errors and the like, consumption on inactive accounts, and collections. These activities will be discussed at length in Chapter 2.

delivery and measurement. Minimizing non-technical losses increases the amount of electricity that is *delivered, measured, and billed.* This is the challenge to revenue security.

Distribution Losses

Losses in power distribution systems have two components: technical and non-technical.

Technical Losses

Technical loss is the component of distribution system losses that is inherent in the electrical equipment, devices, and conductors used in the physical delivery of electric energy.

Technical loss is intrinsic to electrical systems, as all electrical devices have some resistance and the flow of currents will cause a power loss (I2R loss). Integration of this power loss over time, i.e. _ I2R.dt, is the energy loss. Every element in a power system (a line or a transformer) offers resistance to power flow and, thus, consumes some energy. The cumulative energy consumed by all these elements is classified as "technical loss." Technical losses are due to energy dissipated in the conductors and equipment used for transmission, transformation, sub-transmission, and power distribution. These occur at many places in a distribution system—for example, in lines, mid-span joints and terminations transformers, and service cables and connections.

Technical losses vary greatly in terms of network configuration, generator locations and outputs, and customer locations and demands. In particular, losses during heavy loading periods or on heavily loaded lines are often much higher than those that occur in average or light loading conditions. This is because a quadratic relationship between losses and line flows can be assumed for most devices of power delivery systems. It is not possible to altogether eliminate such losses, which are inherent in a system; they can, however, be reduced to some extent.

Technical losses include the load and no-load (or fixed) losses in the following:

- Sub-transmission lines
- Substation power transformers
- Primary distribution lines
- Voltage regulators
- Capacitors
- Reactors
- Distribution transformers
- Secondary distribution lines
- Service drops
- All other electrical equipment necessary for distribution system operations

Technical losses also include the electric energy dissipated by the electrical burdens of the metering equipment such as potential and current coils and instrument transformers.

Technical losses can be calculated based on the natural properties of components in the power system: resistance, reactance, capacitance, voltage, current, and power.

Non-Technical Losses

Non-technical loss is the component of distribution system losses that is not related to the physical characteristics and functions of the electrical system. Rather, non-technical loss comprises distribution system losses caused by factors at the point of delivery and measurement. These are conditions that the technical losses computation fails to take into account. Such losses are caused primarily by human error, whether intentional or not. Non-technical losses are associated with unidentified and uncollected revenue arising from pilferage, tampering with meters, defective meters, and errors in meter reading and in estimating un-metered supply of energy. System miscalculation on the part of the utilities due to accounting errors, poor record keeping, or other information errors also contribute to non-technical losses.

Non-technical losses also can be viewed as undetected load—customers that utilities do not know exist. When an undetected load is attached to the system, the actual losses increase while the losses expected by the utilities will remain the same. The increased losses will show on the utility's accounts, and the costs will be passed along to the customers as transmission and distribution charges.

Reasons for non-technical (or commercial) losses:

- Non-performing and under-performing meters
- Incorrect application of multiplying factors
- Defects in current transformer (CT) and potential transformer (PT) circuitry
- Non-reading of meters
- Pilferage by manipulating or bypassing of meters
- Theft by direct tapping and so on

All these losses are due to non-metering or under-metering of actual consumption. Non-technical losses occur at many places in a distribution system. These are shown in the following insert.[2]

[2] *Best Practices in Distribution Loss Reduction*, DRUM Program, Power Systems Training Institute, Bangalore – 560070. December 2007. The DRUM (Distribution Reform, Upgrades and Management) project is a series of training and capacity building programs in distribution. The broad objective of the training program is to share relevant regional and international experience in the management of distribution business. The program will cover all the important aspects of the distribution business ranging from regulatory matters such as approaches to tariff setting, open access, and reforms to issues of concern to utilities such as quality of service, information management, and energy efficiency. It is supported by USAID and the Ministry of Power, India.

Losses Due to Non-Technical Reasons	
Loss at consumer end meters	Poor accuracy of meters
	Large errors in CTs/PTs
	Voltage drop in PT cables
	Loose connections in PT wire terminations
	Overburdened CT
Tampering/bypass of meters	Where meters without tamper-proof/temper-deterrent/tamper-evident meters are used
	Poor quality sealing of meters
	Lack of seal issue, seal monitoring and management system
	Shabby installation of meters and metering systems
	Exposed CTs/PTs where such devices are not properly securitized
Pilferage of energy	From overhead "bare" conductors
	From open junction boxes (in cabled systems)
	Exposed connections/joints in service cables
	Bypassing the neutral wires in meters
Energy accounting system	Lack of proper instrumentation (metering) in feeders and detector tubes (DTs) for carrying out energy audits
	Not using meters with appropriate data logging features in feeder and DT meters
	Lack of a system for carrying out regular (monthly) energy accounting to monitor losses
	Errors in sending end meters, CTs and PTs
	Loose connections in PT wires (which result in low voltage at feeder meter terminals)
	Energy accounting errors (by not following a scientific method for energy audits)
Errors in meter reading	Avoiding meter reading due to several causes such as house locked and meter not traceable
	Manual (unintentional errors) in meter reading
	Intentional errors in meter reading (collusion by meter readers)
	Coffee shop reading
	Data punching errors (at MRI and by meter readers)
	Data punching errors by data entry operators
	Lack of validation checks
	Lack of management summaries and exception reports on meter reading
Errors in bills	Errors in raising the correct bill
	Manipulation/changes made in meter reading at billing centers—lack of a system to assure integrity in data
	Lack of a system to ensure bills are delivered
Receipt of payment	Lack of a system to trace defaulters, including regular defaulters
	Lack of a system for timely disconnection
	Care to be taken for reliable disconnection of supply (where to disconnect)

Factors Contributing to Non-Technical Losses

Theft and Non-payment

The most prominent forms of non-technical loss are electricity theft and non-payment. Electricity theft is defined as a deliberate attempt by a person to reduce or eliminate the amount of money he or she will owe the utility for electric energy. This could range from creating false consumption information used in billings by tampering with the customer's meter to making unauthorized connections to the power grid.

Power theft by existing customers is the predominant cause of loss of revenue to the electrical utilities. Almost all customer classes are involved in this: residential, commercial, industrial, and public entities. The consequences of power theft are manifest in many areas of an electric distribution company's business, including transformer failures, equipment breakdowns, poor revenue collection, financial losses, lower credit rating for the utility, increased technical losses, and the corroded integrity of employees.

Theft of power is committed by bypassing the meter or meter tampering. Totally bypassing the meter is done by directly tapping into the distribution line; partial or full load is then fed directly.

There are numerous methods of meter tampering. New methods are constantly evolving and detection of tampering is a continuous challenge for distribution utilities.

Theft can be active or passive. A customer may actively engage in illegal tampering to avoid the registration on the meter, or a customer may take possession of a property, find that electricity and gas supplies are on, and therefore not apply for service, thus avoiding payment without tampering.

Direct tapping of power by non-customers is another source of theft that is widely prevalent in developing countries. This is mainly in domestic and agricultural categories. Geographical remoteness, mass basis for theft, poor law enforcement capability, and inaction on the part of utilities are helping this phenomenon.

Unmetered Connections

In some countries, certain customers are not metered and energy usage is estimated, instead of measured, with an energy meter. Usually, the loads involved are small and meter installation is economically impractical. Examples of this are street lights and cable television amplifiers. Unmetered connections pose problems in correctly estimating consumption, resulting in losses.

Defective Metering

Losses due to metering inaccuracies are defined as the difference between the amount of energy actually delivered through the meters and the amount registered by the meters.

Tampered, slow-running, stalled, or damaged meters cause substantial losses to distribution utilities. Electromechanical meters tend to get sluggish over a period of time, thus under-recording consumption. Stopped or damaged meters can be in place for many years, resulting in on-going losses.

Virtually all energy meters are subject to these kinds of errors and inaccuracies. Standards and protocols for accuracy audits, repairs, and replacement are required to ameliorate this situation.

Meter-Reading Errors

Meter-reading personnel occasionally make errors in recording their readings. For a good number of services the meter reader, at times, reports nil consumption without any comment. Sometimes the meter reader furnishes no readings or in some cases, furnishes table readings. Another error is the adoption of wrong multiplier factors.

Estimated Bills

Sometimes customer bills are prepared using estimates of consumption. The method of estimating customer consumption can distort recorded losses.

Late Billing and Poor Revenue Collection

Consumer complaints in the billing process can result from incorrect billing due to deficiencies in metering and data processing. Prolonged disputes, lack of consumer-friendly policies, connivance, incorrect identification of category, fictitious billing (of non-existent consumers), lack of reconciliation, and continuous provisional billing are causes for poor revenue collections and, thus, contribute to non-technical losses.

AMI WITH METER DATA MANAGEMENT (MDMS) CAN MITIGATE MANY OF THE FACTORS CONTRIBUTING TO NON-TECHNICAL LOSSES. THE ENABLING TECHNOLOGIES ARE DISCUSSED IN CHAPTERS 2 AND 3.

Non-Technical Loss Contribution to Technical Loss

It is often overlooked that non-technical losses can be a contributing factor to technical loss because of improper load management. Improper load management can lead to overloading of conductors and transformers in the system causing higher losses.

It can be argued that the distortion of load quantities caused by non-technical losses distorts computations for technical losses caused by existing loads, thereby rendering results ineffectual.[3] Energy diversion is a major aggravating factor in this situation.

Reducing non-technical losses may positively impact technical losses by mitigating congestion during periods of peak load when technical losses are particularly high.[4]

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[3] *Non-Technical Losses in Electrical Power Systems*, Thesis, Fritz J. and Dolores H. Russ College of Engineering and Technology Ohio University, Dan Suriyamongkol. November 2002.

[4] *Electricity Distribution Losses*, Office of Gas and Electricity Markets (UK) January 2003.

Measurement

Non-technical losses, by definition, are losses that are not accounted for and are, therefore, not subject to analytical measurement. Non-technical losses are simply the difference between the energy delivered to the distribution system and billed to end-users, less technical losses. Although there is agreement on the importance of non-technical losses, there is no firm data to define the level of losses on an industrywide basis. However, the importance of non-technical losses, especially in terms of their impact on revenue, is such that distribution utilities try to quantify them.

Such quantification is very difficult. Quantifying what statisticians call "unaccountable for" attempts the impossible. There is an inherent difficulty is obtaining data on unmetered supplies and theft. Estimating the revenue impact of non-technical losses presents yet further difficulties. This is brought into relief when trying to measure the benefits of AMI in reducing non-technical losses. Although there are expectations that AMI will help to reduce non-technical losses, the measurement of benefits (or costs) from AMI deployment are considered non-quantifiable. For example, the framework for the business case adopted by the California Public Utilities Commission lists the reduction of non-technical losses as a benefit, but states that they are "not quantifiable, qualitative."[5]

Utilities rely on studies that are designed to calculate the magnitude, composition, and distribution of system losses based on annual aggregate metering information for energy purchases, energy sales, and system modeling methods. These studies are compared to industry and academic studies and models to establish the magnitude, composition, and distribution of losses.

Utilities have developed methods to measure non-technical losses primarily based on detection by manual meter readings and statistical analysis. These are often inaccurate. This is because the data rely heavily on the records of detected cases, rather than by actual measurement of the electrical power system. The reason that measurement or monitoring the power system is not the preferred method of measuring non-technical losses is because the infrastructure of the system, specifically the metering system, makes accurate and detailed loss determination impossible.[6] Measuring distribution line loses directly is not economic.[7]

The metering system is focused on the end-user, not on intermediary stages in the power distribution where technical and non-technical losses could be more accurately measured.

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[5] *AMI Potential Benefits Categories Recommended Framework for the Business Case Analysis of Advanced Metering Infrastructure* (Draft Report), Moises Chavez, CPUC and Mike Messenger, CEC April 14, 2004. Easier identification of energy theft is categorized as "not quantifiable, qualitative"; meter accuracy, detection of meter failures, reduction in "idle usage," and billing accuracy are categorized as "short term."

[6] *Non-Technical Losses in Electrical Power Systems*, Thesis, Fritz J. and Dolores H. Russ College of Engineering and Technology Ohio University, Dan Suriyamongkol. November 2002.

[7] For the accurate measurement of technical losses on transmission and distribution systems, it would be necessary to install metering equipment at each voltage level of transmission and transformation.

The only real solution for identifying the non-technical loss component from transmission and distribution losses is through studies at the distribution utility level. Technical losses can be isolated at substations, and the differences with end-use consumption calculated from that point. Unfortunately, such studies are not conducted on a consistent or industrywide basis.

To get a magnitude measure of the impact of non-technical losses on revenue for purposes of this study, the approach is to examine aggregate measurements of revenue and "distribution" losses from reliable government statistical sources and apply ratios from various industry surveys and reports. The available data sources and their limitations must be taken into close account when considering the accuracy of the results. Economic loss levels tend to be system-specific. In the end, the resulting measure of revenue impact from non-technical losses is an order of magnitude estimation. Nonetheless, this approach is sufficient to demonstrate the value of each distribution utility taking its own measure of non-technical losses.

Data Sources

Data on revenue losses from non-technical losses are extremely difficult to come by. Data on non-technical losses are not collected by the Energy Information Administration (EIA) or industry associations. Data on the revenue attributable to those losses are not collected or estimated on an industrywide basis. Electric utilities consider these data confidential because they have implications for operating and financial performance.

Statistics on net generation and "transmission and distribution losses and unaccounted for," measured in kilowatt hours, are available in the Annual Energy Review.[8] Statistics on revenue from retail sales to ultimate customers and the supply and disposition of electricity are available from the Electric Power Annual.[9]

The most exhaustive study on revenue *metering* losses per se was made by EPRI in 2000.[10] The focus of this study was metering, anomalies, metering integrity, and theft rather than revenue and the full economic impact of non-technical losses.[11] This study was conducted before the benefits of automatic meter reading (AMR)/AMI had become noticeable. The study looks forward to that day though in its conclusion.

> "[Utilities have] a strong interest in quantifying these losses to assess their full effect on utility revenues and to provide a basis for mitigating technologies, such as Automatic

[8] Table 8.1 Electricity Overview, 1949-2006, Report No. DOE/EIA-0384(2006), Annual Energy Review 2006.

[9] Table 7.3 Revenue from Retail Sales of Electricity to Ultimate Customers by Sector, by Provider, 1995 through 2006 and Table ES2 Supply and Disposition of Electricity, 1995 through 2006, Electric Power Annual. October 22, 2007.

[10] *Revenue Metering Loss Assessment*, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA, Worcester, MA, South Carolina Electric & Gas Co., Columbia, SC and Baltimore Gas & Electric Co., Baltimore, MD: 2001. 1000365.

[11] Ibid. For example, the definition of meter/billing errors states, "Included in this class are all scenarios involving personnel actions, where 'people errors' compromise metering integrity because of inexperience, inattention, lack of review, and lack of training. ... Meter mis-installation falls into this category."

Meter Reading (AMR), and the development of other future programs to reduce non-technical losses."[12]

The Office of Gas and Electricity Markets in the United Kingdom has conducted a number of studies evaluating the cost of distribution losses, including non-technical losses and also illegal abstractions (tampering with meters and illegal connections).[13]

Statistics

Aggregate statistics for transmission and distribution losses are presented in Table 1-1, along with revenue for the corresponding year. From this data the relationships and trends can be observed that offer insights into transmission and distribution losses, technical and non-technical, at a global level. As stated previously in the section on data sources, unfortunately these are the only statistical series that are available that offer an objective and consistent measure of the relevant variables at any level, from generation to end-user.

Table 1-1
Statistics

Key Statistics							
Year	**Net Generation + Imports (million kWh)**	**T&D+UFE Losses (million kWh)**	**Ratio**	**Revenue from Retail Sales ($ million)**	**Revenue Loss T&D+UFE**	**Revenue Loss per million kWh**	**Rev Loss 2.0%**
1996	3,487,684	230,617	6.6%	212,609	14,058	0.0610	4252
1997	3,535,204	224,380	6.3%	215,334	13,667	0.0609	4307
1998	3,659,809	221,056	6.0%	219,848	13,279	0.0601	4397
1999	3,738,025	240,086	6.4%	219,896	14,124	0.0588	4398
2000	3,850,697	243,511	6.3%	233,163	14,745	0.0606	4663
2001	3,775,144	201,564	5.3%	247,343	13,206	0.0655	4947
2002	3,895,231	247,785	6.4%	249,411	15,866	0.0640	4988
2003	3,913,575	227,573	5.8%	259,767	15,105	0.0664	5195
2004	4,004,765	265,918	6.6%	270,119	17,936	0.0674	5402
2005	4,099,950	264,479	6.5%	298,003	19,223	0.0727	5960
2006[P]	4,095,321	250,918	6.1%	326,506	20,005	0.0797	6530

[12] Ibid.

[13] *Electricity Distribution Losses*, Office of Gas and Electricity Markets (UK) January 2003.

Transmission and Distribution Losses, Unaccounted for Energy

"Transmission and Distribution Losses and Unaccounted for" (T&D+UFE) is calculated as the sum of total net generation and imports minus total end use and exports.[14] Transmission and distribution system losses, including "unaccounted for energy," are generally defined as a percentage of the difference between total energy input to the network and sales to all customers.

These losses, as the global statistical measure of both technical and non-technical losses, are commonly compared to the aggregate of "Net Generation and Imports" to provide an indication of their magnitude and impact. This comparison is shown in Figure 1-1.

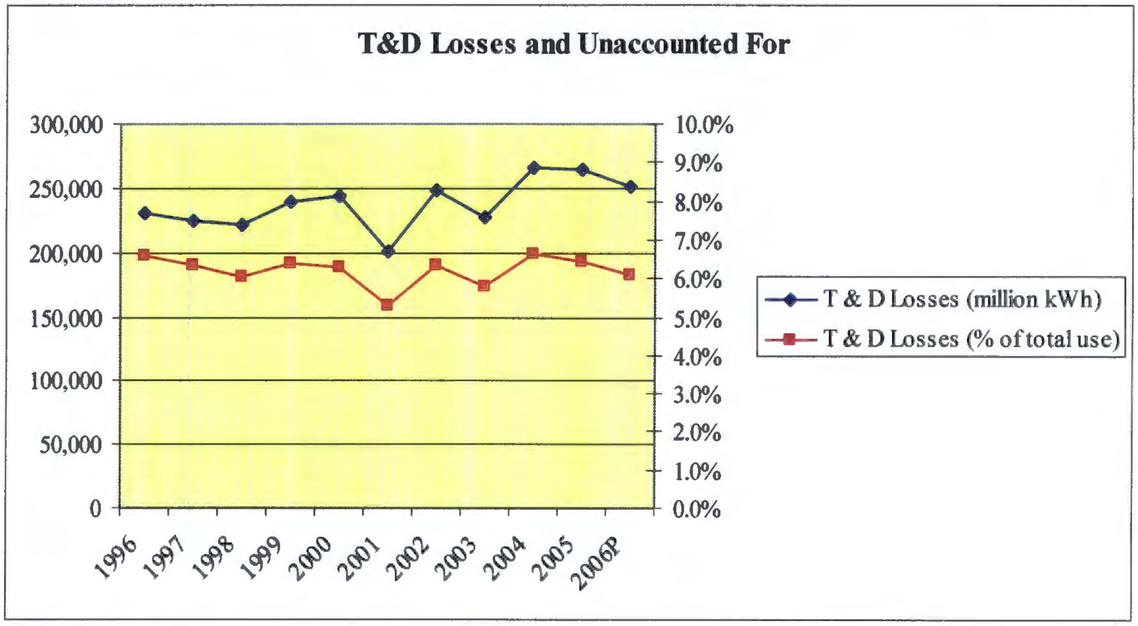

Figure 1-1
T&D Losses

Net Generation and Imports increased from 3.5 quadrillion kWh in 1996 to 4.1 quadrillion kWh in 2006, or 17.4%. Over that same time period, T&D+UFE increased from 230.6 billion kWh to 250.9 kWh, or 8.8%.

The average loss ratio of T&D+UFE to Net Generation and Imports was 6.2% over the eleven years from the beginning of 1996 to the end of 2006.

Revenue and Loss Trends

Revenue increased from $212.6 billion in 1996 to $326.5 billion in 2006, or 53.6%, while T&D+UFE increased only 8.8%. The trend lines for these increases are shown in Figure 1-2. For purposes of this study, it is significant to note that the trend for revenue increases is greater than T&D+UFE. This has a major impact on the importance of revenue loss from non-technical losses.

[14] *Annual Energy Review 2006*, Energy Information Administration, Department of Energy.

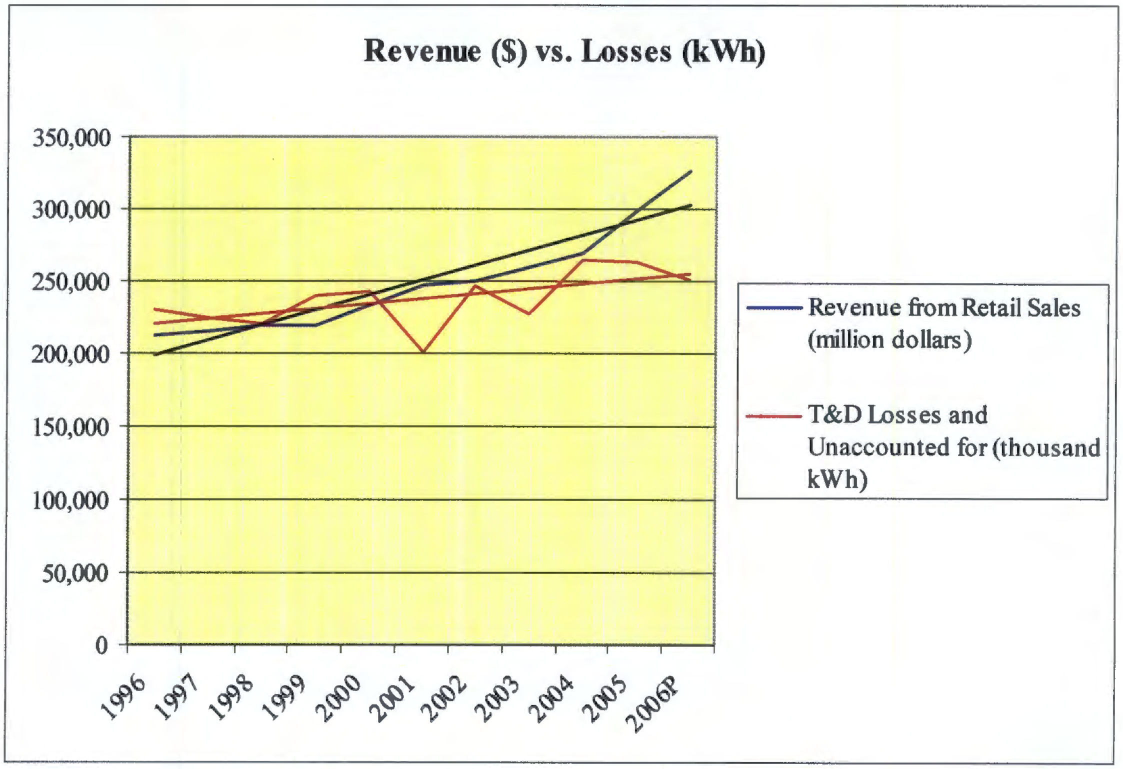

Figure 1-2
Revenue ($) vs. Losses (kWh)

Non-Technical Revenue Loss Estimate

It is difficult to ascertain the extent of technical and non-technical distribution losses separately. The reasons for the difficulty in estimating non-technical losses are discussed in the section on measurement above. For purposes of comparison, and again to get an order of magnitude view of the importance of non-technical revenue losses, a percentage of 2% is most often cited by experts in the industry (Figure 1-3). Applying a constant for the loss ratio, non-technical revenue losses parallel the global.

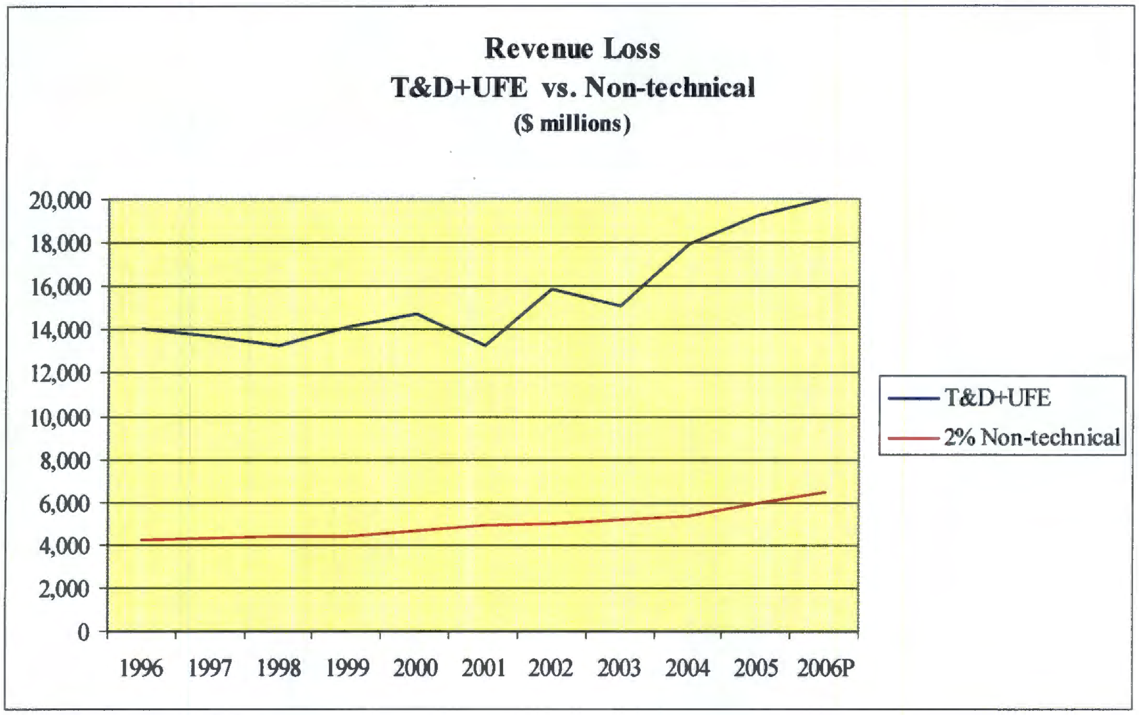

Figure 1-3
T&D+UFE vs. Non-Technical

Revenue Loss per kWh

With revenue rising at substantially higher rates than T&D+UDE losses, revenue loss per kWh is dramatically impacted. Each unit of technical and non-technical losses carries a higher revenue cost, just as each billed kWh carries a higher rate. The upward trend in revenue loss per kWh is shown in Figure 1-4.

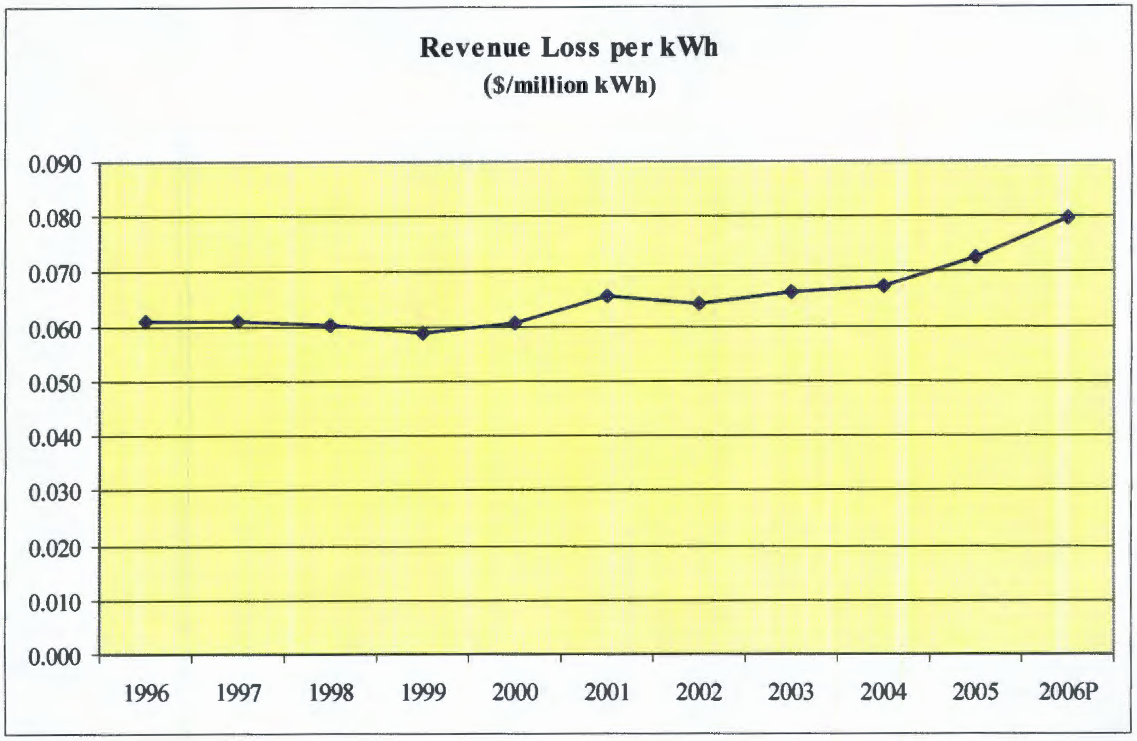

Figure 1-4
Revenue Loss per kWh

Whatever other inferences may be drawn from the data or conclusions reached about technical and non-technical losses, the fact remains that the revenue loss per kWh is increasing. The increases in these losses may be attributable to technical or non-technical components. However, it is most likely that they are more a function of revenue increases themselves. Energy costs have risen over the past decade, and this naturally is reflected in the value of units sold or units lost. Suffice to say, each kWh of reduction in non-technical loss brings the recovery of more revenue today than it did ten years ago.

Assuming that the ratio of non-technical losses to generation remains the same, the value of non-technical losses measured in $/kWh will be higher in terms of revenue. This should be taken into consideration when comparing the revenue losses in earlier studies (prior to 2002) to revenue losses today.

Non-technical revenue loss is greater today than ten years ago, placing greater importance on measures for their reduction.

Studies and Reports

Arizona Public Service Study

After reflecting on several reports and surveys from 1997 to 2000, the Revenue Protection Department at Arizona Public Service (APS) came to the conclusion that "available information regarding energy theft continued to be subjective, at best."[15]

The revenue protection team at Arizona Public Service Company decided to conduct a study of its own.

Two prior studies provided direction and information regarding the amount of various meter problems found in the field and could cite specific percentages. One study by United Energy determined that 2.16% of its meters were faulty. The other study, by the Canadian Electricity Association, found deviations (meter tampering), that would certainly lead to diversion, were definitely occurring across Canada. The average rate for these deviations (tamper rate) was 1.36%.[16]

The goal of the research study at APS was to determine the dollar amount of loss to theft and diversion.

The data in the APS study pointed to a much higher percentage loss among commercial accounts. Of the $7.9 million actual/probable loss, $5.1 million was attributed to commercial accounts. And, similar to the Canadian study, a large number of meter maintenance items were noted. Fully, 6.5% of the meters in the study had some type of maintenance problem.

The APS study concluded that 1.72% of meters were subjected to some form of tampering and that the associated revenue loss was $7.9 million, or 0.518% of revenues.

EPRI Study

The EPRI study on revenue metering loss assessment in 2001[17] concluded that there is "a widespread but unsubstantiated impression in the utility industry that revenue loss from all non-technical sources (excluding bad debt) is between 3% and 4% of utility revenue. Based on this work, we conclude it is far more likely that such losses are between 1% and 2%, and almost certainly are less than 3%. Of course, there will be exceptions in some utility territories. But today's well-managed utility with proactive revenue protection programs should fall below 2%.

[15] *Research Study Quantifies Energy Theft Losses*, John J. Culwell, Supervisor, Revenue Protection Department, Arizona Public Service, Metering International - Issue 1, 2001. January 29, 2001.

[16] Extent of Energy Division on Customer Premises for Canadian Utilities.

[17] *Revenue Metering Loss Assessment*, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA, Worcester, MA, South Carolina Electric & Gas Co., Columbia, SC and Baltimore Gas & Electric Co., Baltimore, MD: 2001. 1000365. This report describes three field studies at three utilities in the United States that inspected meters at over 1000 small- and medium-sized industrial and commercial sites and discusses the available options for utilities seeking to reduce their metering losses.

"Measured in dollars, this gives the following result: A 1.5% average loss corresponds to about $30 million annually for a utility with a million customers and $2 billion of revenue. This equates to about $30 per customer. If the loss is at the upper end of the range, that is 3%, the loss for the same utility corresponds to about $60 million per year, or $60 per customer."

Itron Report to U.S. Department of Energy

In a report submitted to the U.S. Department of Energy in 2005 Itron stated,

"… theft of energy services costs utilities, their shareholders and consumers billions of dollars each year. The consensus estimate among most industry groups and analysts is that energy theft in the U.S. stands between .5 percent and 3.5 percent of annual gross revenues. With U.S. electricity revenues at $280 billion in the late 1990s, theft of electricity alone would equate to between $1 billion and $10 billion annually. A recent article in the Wall Street Journal estimated the nationwide electricity theft figure at $4 billion per year. And with energy prices increasing sharply nationwide, theft of energy services is only likely to increase as consumers struggle to pay energy bills that have doubled or tripled over the past year."[18]

San Diego Gas & Electric

SDG&E demurred from the CPUC Framework for Business Case guidance that benefits from the reduction of theft were non-quantifiable. It proceeded to quantify benefits from AMI in its own business case based on its own estimates of theft. SDG&E claimed $69.4 million in benefits associated with reduced energy theft (both electric and gas), improved meter accuracy, and reduced billing exceptions.[19]

In its opinion approving SDG&E's AMI project, the CPUC stated,

"At the time of the July 2004 Ruling, it was not clear whether energy theft benefits would be quantifiable. That Ruling did not rule out future quantification of benefits. SDG&E has in fact quantified these benefits. We have reviewed SDG&E's calculations of energy theft benefits and find them to be reasonable."[20]

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[18] *The Critical Role of Advanced Metering Technology in Optimizing Energy Delivery and Efficiency*, A Report to the U.S. Department of Energy, Itron. October 2005.

[19] *Meter Reading and Customer Service Field Functions, Safety, Billing and Revenue Protection*, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, Chapter 3, Prepared Supplemental, Consolidating Superseding and Replacement Testimony of James Teeter, SGD&E before the CPUC, March 28, 2006.

[20] *Opinion Approving Settlement on San Diego Gas and Electric Company's Advanced Metering Infrastructure Project*, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, CPUC. March 8, 2007.

However, there was a procedural qualifier:

"It is unreasonable for SDG&E to include benefits which are not within the scope of benefits envisioned for this proceeding and therefore operational benefits should be reduced by $14.5 million."

Further, SDG&E claimed that no more than 0.65% of electricity revenue is lost due to meter error, energy theft, and unaccounted for energy, including meters that fail and mechanical meters that slow down over time as mechanical parts wear out.

In response to a CPUC data request, SDG&E reiterated that many references provide industry estimates for energy theft and all are consistently in the 1-2% range. The explanation for the basis of this figure was that total losses are not known. Field studies at samples of meter sites uncovered approximately that number of incidences of theft, and five sites published studies that report theft in that range.[21]

Hydro One Estimate

Non-technical losses were estimated by Hydro One by reviewing losses from theft, meter inaccuracies, and unmetered energy in other jurisdictions. Based on an overview of the non-technical losses value from utilities across North America, United Kingdom, and Australia, a value of 1.2% was recommended as a reasonable estimate.

Published figures for the level of non-technical losses in North America are very difficult to obtain. In California "unaccounted for energy" is defined as the difference between the energy purchased and the energy sold in a utility service territory after accounting for imports, exports, and technical line losses. This includes the first three categories of non-technical loss listed above. Estimates from different utilities range from 3.9 to 5% of energy sales.[22]

Published figures for theft alone in the United Kingdom estimate levels at 0.2 to 1% of energy sold. The upper limit of this range is used in Australia by regulatory commissions as a reasonable estimate in the calculation of distribution loss factors.

"In the past Hydro One has used a figure of 10% of the technical losses to estimate non-technical losses. With technical losses at approximately 6% of energy sold, this represents only 0.6% of energy sales as an estimate for non-technical losses. This is well below (<15%) the published figures for utilities in North America and is less than that used in Australia or most of the United Kingdom. A more reasonable estimate for theft and other non-technical losses would by 1.2% of energy sales."[23]

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[21] DRA Data Request Number 15, A.05-03-015, SDG&E Response.

[22] *Comments of the California Energy Commission Staff on the Report on Unaccounted for Energy and Upstream Metering*, Caryn Hough.1998.

[23] Distribution Line Loss, Exhibit A, Tab 15, Schedule 2, 2006 Distribution Rate Application (EB-2005-0378), Filed August 17, 2005.

Industry Reports

Industry experts estimate that on average, utilities are losing between 2% and 4% in revenues in the meter-to-cash cycle. Studies on electric and gas meter-to-cash cycle losses, also referred to as non-technical revenue losses, indicate that 80% of these losses can be attributed to theft, defective metering, and soft shutoff policies.[24]

Limitation

Some estimates of loss percentages (for example, the 1.5% figure) seem to be predicated mostly on losses from theft. Most of these loss estimates include only the detection of simple energy theft. There may be thefts that are not detected due to sophisticated bypass.[25] Other contributors to non-technical losses, such as defective meters and billing errors, should be given greater weight when deciding on the most likely percentage. Thus, the 1.5% figure is considered as being at the low end of the estimate for non-technical losses.

Revenue Loss

Considering the referenced studies and reports, statistics and analysis, and the opinions of industry experts in revenue protection, a reasonable percentage for non-technical losses is 2.0%. There are indications that the associated revenue loss might be at a lower level, say 1.4%. Some individual company studies suggest that the ratio for revenue losses is lower than the percentage for energy losses. An opposing argument points to the revenue effect due to higher rates reflecting rising energy costs. Nonetheless, for purposes of this study and for comparisons with other estimates in the industry, applying the 2% ratio to revenue seems credible.[26]

The statistical measures for technical and non-technical losses in terms of energy are relatively constant at around 6.1% in the United States. Although there are reasons to argue that technical losses have increased over the past ten years due to congestion, these technical variances are not thought to be greater than the variance in the ratio for losses using aggregate figures. A major study of transmission and distribution losses would be required to conclude otherwise.

Although the statistical measures do not differentiate between transmission and distribution losses, let alone identify non-technical losses (which are, after all, "unaccounted for"), the ratio for non-technical losses measured in terms of energy units cannot reasonably be larger than 4%, given the relative constancy of transmission losses.

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[24] Ken Silverstein, Editor-in-Chief, *EnergyBiz Insider*.

[25] There are reasons for bypassing the electric system than avoiding payment. One is the concealment of illegal activity. For example, the main source of electrical theft in Canada derives from indoor marijuana grow operations. The Electricity Distributors Association (Ontario) says statistics show grow operators steal an average of $1500 of electricity per kilowatt-hours per day or 10 times the electricity consumption in an average home. Estimates in Ontario, Canada, alone list over a $500 million power theft loss. Reports of seizures of large indoor grow operations list over a 90% electrical theft/bypass rate.

[26] In the absence of industrywide studies of technical and non-technical losses using a consistent methodology, this is a reasonable and sufficient basis for a discussion of the impact of AMI on non-technical losses.

The findings of numerous studies vary widely with respect to the level of non-technical losses, and even more so when imputing non-technical revenue losses.[27] Estimates of tamper rates range from 1.36% to 1.72%. Metering surveys indicate that defective meters may range from 2.16% to 6.5% of the total installed base. Related revenue losses are imputed anywhere from 0.50% to 3.5%. Many of the differences among these estimates derive from analyzing different customer bases and service territories while other differences relate to measurement difficulties with technical losses.

Estimates of non-technical revenue losses range from 0.5% to 4.0% of annual revenue. The 0.5% estimate is so low as to be almost a margin of error in estimation. Most likely, it relates to simple tampering, excluding by-pass and other sources of non-technical losses. The 4.0% estimate is unrealistically high, most likely based on worst-case scenarios.

Non-technical revenue losses most likely fall within a much narrower range: 1.65% to 2.15%, depending on the utility and service territory. Non-technical revenue losses, within this percentage range, over the past ten years are shown in Figure 1-5.[28] A "mode" of 2% would appear reasonable and reflective of the impact on distribution utilities.

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[27] Tamper rates and meter defect information are largely taken from surveys, not a complete census of customer bases. These are subject to wide variances, especially between utilities with different customer mixes. With few surveys at a limited number of utilities, it is difficult to apply them on a global scale.

[28] It should be kept in mind that the growth in non-technical revenue losses over the past ten years is a function of both the level of revenue and the non-technical loss rate. Utility revenues have increased significantly over the past ten years with the rise in energy costs. Thus, even while assuming a constant non-technical loss ratio and undertaking vigorous revenue assurance measures, the impact on revenue is increasing significantly. Further, high costs and rates may lead to increased theft by tampering and diversion by changing the risk/reward ratio. High costs make the "reward" more attractive; AMI/MDMS is a resource for increasing the "risk."

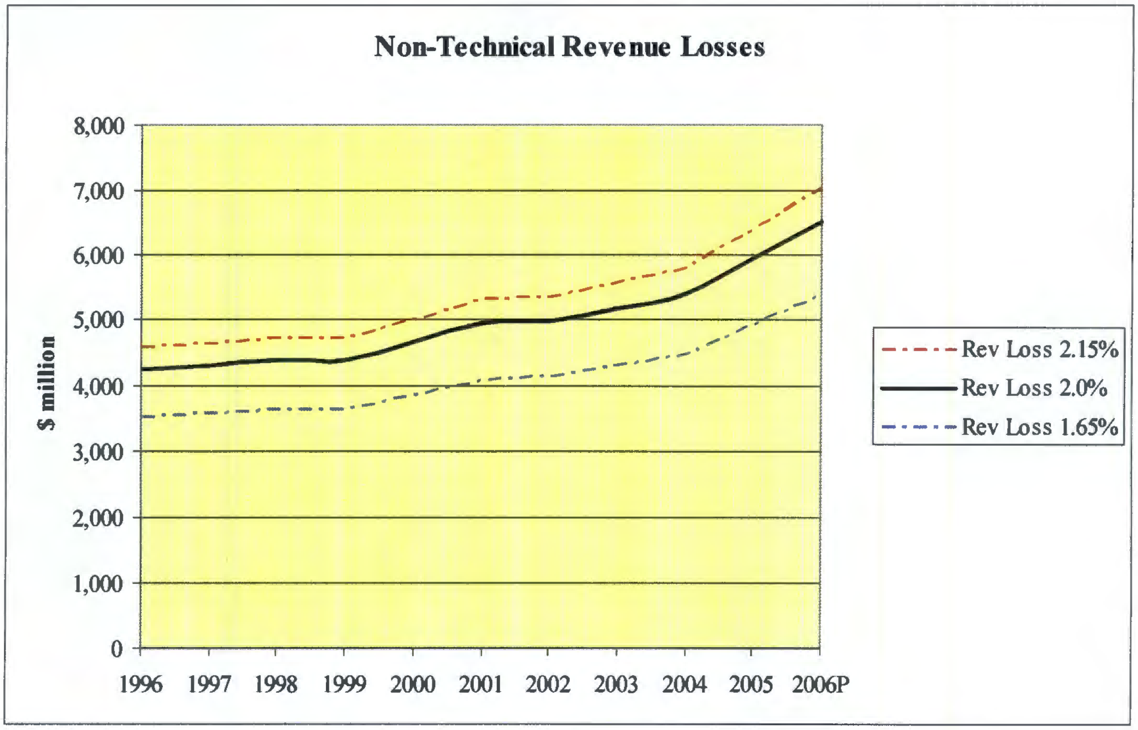

Figure 1-5
Non-Technical Revenue Losses by Year

Based on the 2% rate, non-technical revenue losses are estimated at $6.5 billion for 2006.

International Comparisons

United Kingdom

During the 1980s, some UK electricity companies were losing 2-½% of their total sales because of illegal abstraction (theft) alone. The worst hit areas were London, Merseyside, and Glasgow, with the Northeast having the least amount of theft losses.

Data concerning losses were gained by inter-company comparisons, statistical studies, and engineering studies along with comprehensive studies on street lighting loads to determine distribution system losses and units used in unmetered supplies. This work was underpinned by a number of substation metering exercises whereby meters on particular feeder cables in substations were used to compare the summated meter readings from the properties supplied by those cables.[29]

[29] *Theft of Electricity (Illegal Abstraction)*, Comments and Observations, Terry Keenan, Senior Manager, Manweb, Fellow of the Institution of Electrical Engineers (UK). Comment on Ofgem's Theft of Electricity and Gas Consultation Document.

Overall, Manweb[30] concluded that distribution losses accounted for 5% losses, unmetered supplies (for example, street lights) accounted for 1% losses, and theft accounted for 2-½% losses. This was evidenced by the various studies, metering exercises, signs of serious interference found, and the number of successful prosecutions.

Estimates from four distribution utilities, however, indicate that non-technical losses account for about 3 to 9% of total losses on distribution networks in Great Britain.[31]

Other studies of theft alone in the United Kingdom estimate levels at 0.2 to 1% of energy sold.[32]

Ontario, Canada

Based on an overview of the non-technical losses from utilities across North America, United Kingdom, and Australia, Hydro One considers a value of 1.2% to be a reasonable estimate for Ontario.[33] This ratio is in line with typical losses incurred by other utilities with a similar mix of rural and urban customers in Ontario. However, it may be low when losses from meter bypass in rural areas are fully discovered and accounted for.[34]

Published figures for the level of non-technical losses in North America are very difficult to obtain. In California, "unaccounted for energy" is defined as the difference between the energy purchased and the energy sold in a utility service territory after accounting for imports, exports, and technical line losses. This includes the first three categories of non-technical loss listed above. Estimates from different utilities range from 3.9 to 5% of energy sales.[35]

India

The problem of electricity theft is most pronounced in India, where an estimated one-third of all power is "free." Many users there run their own wires from the distribution lines into their homes. This is a tremendous hazard as the cables are strung through populated alley ways and corridors.

[30] Manweb, a subsidiary of Scottish Power, was among the first electricity companies to gain approval to enter the new market for electricity metering services to domestic and small business customers, which was opened up to competition in June 2004. Under the new arrangements, electricity suppliers have freedom to choose their own agent to collect and process meter readings and to provide and maintain metering equipment. These activities were previously provided on a monopoly basis by the local electricity company.

[31] *Electricity Distribution Losses*, Office of Gas and Electricity Markets (UK). January 2003.

[32] *Report on Distribution System Losses*, J.A.K. Douglas, N.J.L. Randles, PB Power report 10025D008, Victoria Australia. February 4, 2000.

[33] *Distribution System Energy Losses at Hydro One*, Kinectrics Inc. Report No.: K-011568-001-RA-0001-R00. July 20, 2005.

[34] Refer to the accounts of theft in Calgary, *Electricity Theft and Marijuana Grow Operations*.

[35] *Comments of the California Energy Commission Staff on the Report on Unaccounted for Energy and Upstream Metering*, Carolyn Hough, California Energy Commission. 1998.

Energy theft costs India's utilities close to $5 billion a year and is the major contribution to operating deficits.

These non-technical losses have costs well beyond the impact on revenue. The revenue losses impact the financial strength of the utility to the point that investments in infrastructure are prohibited. When energy is not paid for, the company is not recovering its costs and, thus, is unable to invest in new infrastructure. The result is regular power cuts. Without these investments, service degrades and further losses—technical and non-technical—ensue. For example, in May 2008 the Maharashtra State Electricity Board of India announced that it has been able to reduce non-technical losses by as much as 8% and says that, as a result, it will be able to reduce power cuts in the state.

United States

Losses in the United States in the 3% range seem low in comparison to India. However, when the related revenue losses are calculated, the number captures the attention of regulators and the electric utility industry. There are losers from non-technical losses in the United States as well as less developed countries.

Distribution Loss Ratios

Distribution loss ratios—calculated from generation to end-user—can be compared internationally (Figure 1-6). For developed countries, the ratio is lower than 8%, with non-technical losses in the range of 1.5% to 3.5%. For countries still developing, the loss ratios are more than double, with non-technical losses (mostly from theft) being the major explanation.

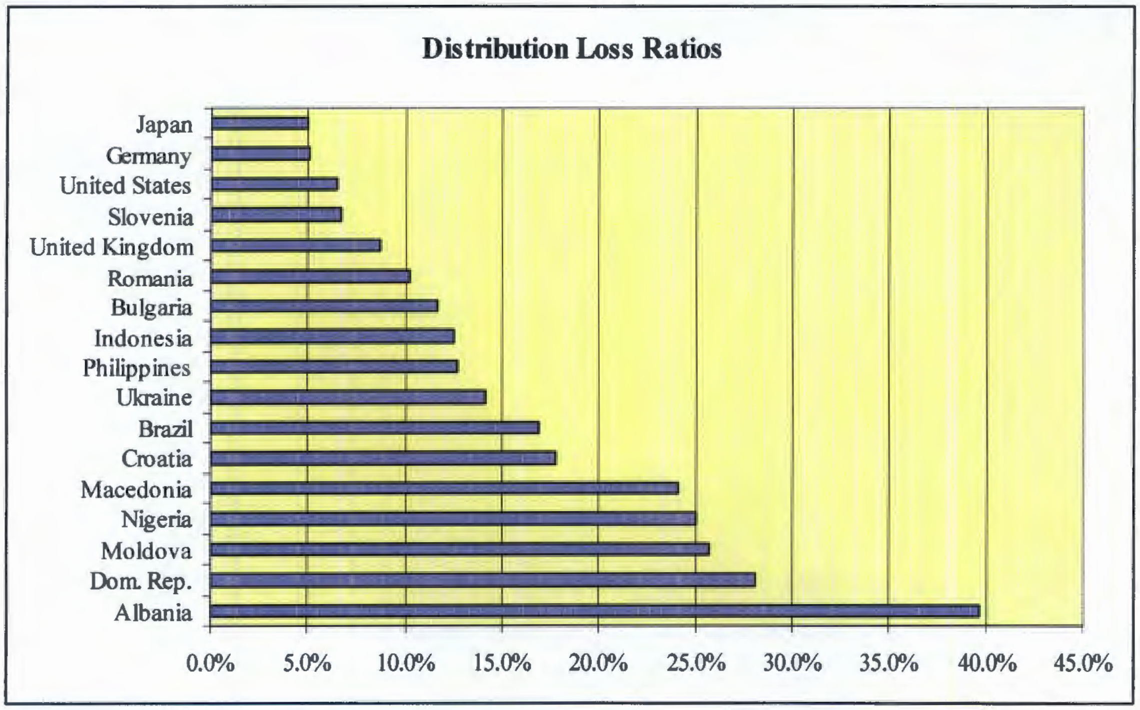

Figure 1-6
Distribution Loss Ratios

Revenue loss resulting from non-technical losses exceeds 40% in many developing countries.[36] Revenue losses of these dimensions have a significant impact on the local economy.[37] It is a problem that governments and utilities must address together. As one observer remarked, "The theft of energy is the largest systematic theft in the world."[38]

Losses Other Than Revenue

Safety

While theft of service is a huge source of revenue loss by any measure, more importantly it poses a serious threat to the safety not only of individuals involved in the theft, but also of utility personnel and the general public.[39] Meter tampering, bypassing, and other means used to steal service place those committing the theft, their families, emergency service personnel, and innocent bystanders in grave danger.

In situations where power must be shut off within a home or business, emergency personnel are at risk of electrocution or burning because meters that have been tampered with may remain "live."

Safety hazards can result in serious injury or death and destruction of public or personal property. These hazards have very real costs associated with them in terms of medical care, loss of productivity, damage to property, and sometimes even services with economic value.

Efficiency

Since losses are factored into the revenue requirement by way of distribution loss factors, and thus included in the rate base, some conclude that there is no real revenue loss to the distribution utility. In this view, reductions in non-technical losses merely shift the source of revenue for the utility among ratepayers. Aside from issues of basic fairness in having some ratepayers bear the burden of non-payment by other users of electricity, the existence of non-technical losses introduces basic inefficiencies into the distribution system.

Non-technical losses have an "efficiency cost." Although a reduction in non-technical losses will represent a reallocation of, rather than a reduction in, electricity consumption, the misallocation of resources introduces inefficiencies. Instead of a direct improvement in social welfare, a redistribution of benefits occurs from those agents whose consumption has been

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[36] *Controlling Electricity Theft and Improving Revenue, Reforming the Power Sector*, Note Number 272, Public Policy for the Private Sector, World Bank. September 2004.

[37] For example, in India electricity theft leads to annual losses estimated at US$4.5 billion, about 1.5% of GDP. The losers are honest consumers, poor people, and those without connections, who bear the burden of high tariffs, system inefficiencies, and inadequate and unreliable power supply.

[38] Kurt W. Roussell, Manager, Revenue Protection, We Energies.

[39] *How Safe is your Utility from Theft of Service?* Revenue Protection Task Force, Energy Association of Pennsylvania. The objective of the Revenue Protection Task Force is to provide education to the public, law enforcement agencies, legislators, and regulators about the facts of energy theft in terms of frequency and quantity of theft.

identified to suppliers and general consumers. However, if consumed units of electricity are correctly allocated, cost signals should encourage a more efficient level of demand for electricity.[40]

The trend toward performance-based rate making highlights the issue of losses where their reduction may change this situation and put in place greater incentives for utilities to reduce non-technical losses.

The reduction of non-technical losses reduces these inefficiencies and rectifies a situation where "lost revenues from energy theft and failure to detect meter errors put upward pressure on rates." Ratepayers benefit when energy theft and meter errors are detected sooner and costs are shifted to the customer who actually used the energy."[41]

Then there is the question of basic fairness. "Although the total revenue requirement does not change through the reduction of energy theft, all law-abiding customers will have lower rates. This is a quantifiable and tangible benefit for our customers."[42]

Technical and commercial losses, however defined, affect allowed tariff levels through a two-step process as shown in Figure 1-7:

<u>Step 1 – Calculation of T&C</u>

$$\text{T\&C} = 1 - \left\{ \frac{\text{Energy Units Billed}}{\text{Energy Units Purchased}} \times \frac{\text{Collection in \$}}{\text{Billing in \$}} \right\}$$

<u>Step 2 – Gross-up Calculation</u>

$$\text{Allowed Units of power purchased} = \frac{1}{1 - \text{T\&C}}$$

Figure 1-7
Calculations

[40] *Electricity Distribution Losses*, Office of Gas and Electricity Markets (UK). January 2003.

[41] *Opinion Approving Settlement on San Diego Gas and Electric Company's Advanced Metering Infrastructure Project*, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, CPUC. March 8, 2007.

[42] Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, Chapter 29, Prepared Rebuttal Testimony of James Teeter, SGD&E before the CPUC. September 7, 2006.

The level of losses, therefore, has a direct impact on the price of electricity consumed. The cost of losses is generally spread out over all users.

It must be noted that the full cost of technical losses on a network consists of not only the value of the electricity lost, but also the cost of providing the additional transportation capacity and the cost of the environmental impacts associated with the additional generation that is needed to cover losses.

Unmetered Demand

Loss in revenue results from the uncontrolled increase in demand from unmetered customers. Also, dissatisfied and angry customers can overload the system, which may lead to faults in the distribution network and load shedding with consequent loss of revenue from customers affected.

Energy Theft Impact on Revenue Ratepayer

Energy theft occurs and is a cost of doing business that is borne by all ratepayers. Any reduction in energy theft from the implementation of automated meters will enable SCE to spread its revenue requirement over more energy sales, thus reducing rates.

Edison Smartconnect™ Deployment Funding and Cost Recovery, Errata to Exhibit 3: Financial Assessment And Cost Benefit Analysis, California Public Utilities Commission. December 5, 2007.

Investigation and Prosecution

The adverse financial impacts of energy theft include lost revenues and the costs for investigation and prosecution. Although these costs are not included in non-technical losses, they are borne by ratepayers nonetheless.

Societal Cost and Theft Comparisons

The public is aware of losses from identity theft, stolen credit cards, hold-ups, and personal robberies. In contrast, the theft of electric and natural gas service, despite the magnitude of the problem, has not received much attention from the public or from regulators.

The cost of non-technical losses in electricity distribution to society can be placed in perspective by comparing it to property crimes.

In the Uniform Crime Reporting Program[43] (UCR), property crime includes the offenses of burglary, larceny-theft, motor vehicle theft, and arson. The object of the theft-type offenses is the taking of money or property, but there is no force or threat of force against the victims. The property crime category includes arson because the offense involves the destruction of property. Property crimes accounted for an estimated $17.6 billion dollars in losses.

[43] *Crime in the US, 2006* US Department of Justice, Federal Bureau of Investigation. September 2007.

Larceny-theft is the crime category closest to theft of electrical services. The UCR Program defines larceny-theft as the unlawful taking, carrying, leading, or riding away of property from the possession or constructive possession of another. Examples are thefts of bicycles, motor vehicle parts and accessories, shoplifting, pocket-picking, or the stealing of any property or article that is not taken by force and violence or by fraud. There were an estimated $5.6 billion dollars in lost property in 2006 as a result of larceny-theft offenses.

The revenue estimate for non-technical losses is $6.5 billion. A comparison of non-technical losses to other thefts crimes is shown in Figure 1-8.

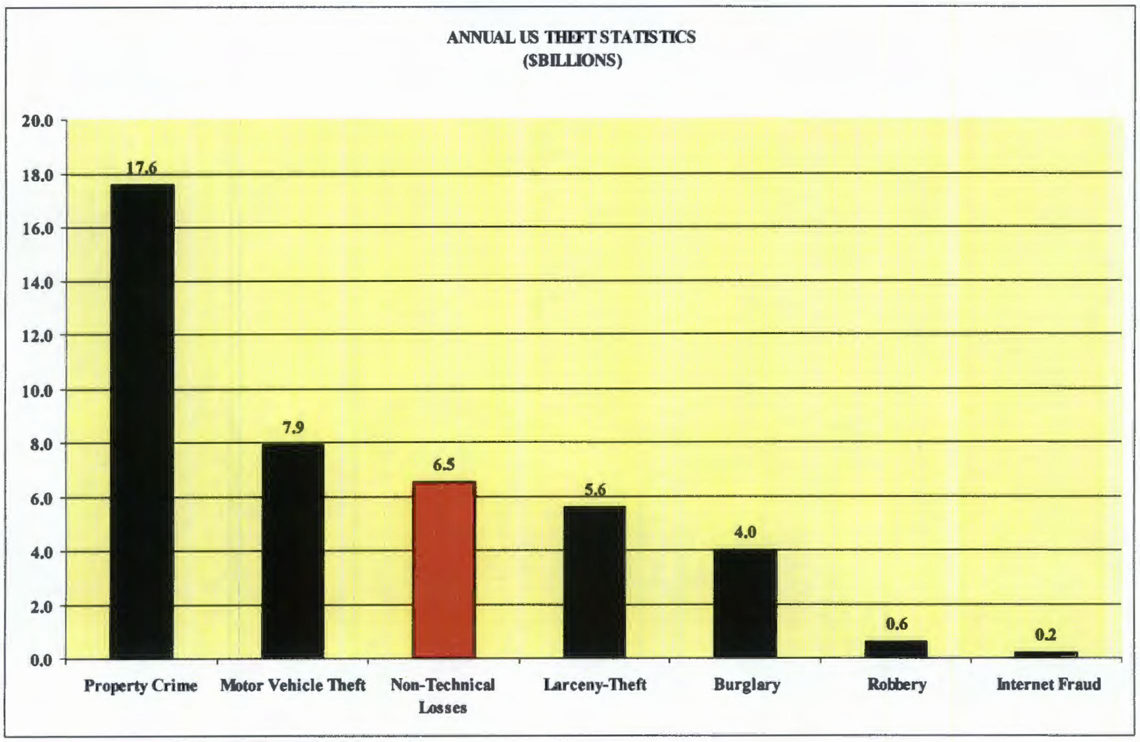

Figure 1-8
Annual U.S. Theft Statistics

2
CHAPTER 2

Revenue Security

"Revenue security" is an apt term to describe the activities intended to protect the distribution system and network resources from external attack or internal subversion, especially theft from diversion by means of "meter bypass." Revenue security ensures that the resources of the electricity industry are available only to those who have the legitimate right to use them. Thus, "revenue security" describes the precautions taken to ensure against non-technical losses.

The activities involved in revenue security are oftentimes called "revenue protection", or more recently, "revenue assurance." Three definitions are presented in the inset below.

Definitions

The term "Revenue Protection" is a colloquialism used by the English-speaking world to refer to the prevention, detection, and recovery of losses caused by interference with electricity and gas supplies.
UK Revenue Protection Association

Revenue Protection is a set of activities to reduce the unauthorized use of energy, ensure metering accuracy and detect meter tampering, and identify customers who fraudulently obtain service.
Kurt W. Roussell, Manager-Revenue Protection, We Energies

Revenue Assurance: A set of activities designed to increase the revenue from providing electric service to ultimate customers, including locating meters without associated customer accounts, relatively high line losses compared with other similar locations, energy theft, and/or improper metering installations.
Federal Energy Regulatory Commission (FERC)

The revenue security function is traditionally performed by utilities' revenue protection departments, using data collected by manual meter reads. The introduction of remote meter-reading technology—beginning with automated meter reading and later including advanced metering systems—changed methods and procedures used for revenue protection, eventually evolving to revenue assurance. These changes in technology and their impact on revenue security are the subject of this chapter.

Meter Readers: The Need for "Eyes in the Field"

The time-honored way of finding electricity theft is through detection by meter-reading personnel. Meter readers are trained and experienced in detecting theft from meter tampering and bypass, and they inspect meters for tampering during regularly scheduled on-site meter reads.

The methods of meter tampering vary from elementary to sophisticated. The ones most commonly detected by meter readers are shown in the insert below.

Common Tampering Techniques

- Stolen meter
- Magnets
- Wire tap on service
- Inverting meter
- Debris, foreign objects inside glass
- Potential link
- Internal—gears, disc, dial hands, adjustment screws
- Load (customer) wires connected to line
- Jumpers—wires connecting line to customer connection

There is some apprehension that AMI, notwithstanding the tamper detection mechanisms in AMI systems, may increase energy theft due to the loss of "eyes in the field" when meter readers no longer visit every meter every month. For example, AMI does not specifically detect and report some kinds of theft, such as taps ahead of the meter.

> "The overall conclusion is that AMR, although it can provide valid and useful assistance in the detection of theft and interference if the system is well thought out and well designed, is not the full answer and that it would be prudent to retain or develop some form of back-up, in terms of conventional revenue protection measures. For instance, one company with an AMR system is considering a new post of Meter Inspector to carry out periodic inspections of customer installations."[44]

There is a concern that AMI—especially after complete meter replacement—will lead to more sophisticated thefts and more bypass, both above and below ground.

Many of these apprehensions and misgivings are founded in experiences with earlier AMR installations. While these are valid concerns, a comparison of AMR and AMI should bring perspective.

[44] OFGEM Consultation on Domestic Metering Innovation, Response by the United Kingdom Revenue Protection Association, Version 3 (final). March 15, 2006.

Comparison of AMR and AMI

Energy theft detection capabilities in AMI systems are far superior to those in simple, first-generation AMR systems. The "infrastructure" in an AMI system includes information systems capable of processing large amounts of interval data for use in discovery of energy theft. This contrasts dramatically with AMR systems, which generally automate only the monthly consumption read.

Prior AMR (not AMI) installations involved tamper alarms so sensitive that false alarms could easily overwhelm the system. Unlike the AMR systems, AMI can intelligently sort and prioritize tamper flags, reducing unnecessary investigations. In addition, AMI, using solid-state meters, is far more tamper-proof than AMR. For example, a solid-state electric meter does not have a spinning disc that can be slowed down. Inverted meters also can be detected quickly through the daily collection of hourly data. Other forms of theft will be discovered through investigation of tamper flags.

AMI solutions involve the retrieval of daily or hourly consumption readings and use database information (comparisons with prior once-a-month readings) to identify locations where theft might be taking place. MDMS applications are essential in the delivery of these solutions. The effectiveness of these solutions is not yet fully documented, as AMI/MDMS have not been deployed on a wide scale over a long period of time. Nevertheless, all indications are that they will be successful when combined with aggressive revenue protection programs with well-trained meter revenue protection agents. With off-cycle reads being supplied through the MDMS, as much as 95% of field service orders for special reads can be eliminated.45

Many on-site inspections by traditional meter readers were focused specifically upon meter tampering and meter anomalies, but did not reach more deeply into supply and service wiring where taps and bypasses are likely to be found. AMI reduces the number of routine site inspections and allows the meter revenue protection agent to concentrate on serious issues of diversion.

AMI Contribution to Theft Reduction

After the installation of AMI, it is expected that utilities may uncover a substantial number of previously unknown sources of diversion. Indeed, some utilities are planning to add staff to handle the increased number of theft cases that will be uncovered.

"During the installation period, SDG&E will need six additional Meter Revenue Protection agents to handle the large number of energy theft cases the company anticipates discovering when the new meters are installed. There also will be some transitional costs during the first year to determine the best way to process false positive signals. After AMI installation is complete, SDG&E will require two additional agents to prosecute the large number of energy thefts we expect to uncover."[46]

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[45] *Meter Data Management System—What, Why, When, and How*, Hahn Tram and Chris Ash, System Engineer, Enspiria Solutions. August 29, 2005.

[46] *Meter Reading and Customer Service Field Functions, Safety, Billing and Revenue Protection*, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, Chapter 3, Prepared

With comprehensive AMI/MDMS and vigorous meter revenue protection programs, the most likely outcome is that AMI will bring a reduction in non-technical losses due to theft.

Meter Reader Shortcomings

At the same time, it should be kept in mind that there is an existing level of theft occurring even with manual readers in the field. In some cases, field-level engineers have not been made responsible or accountable for the energy input to their areas, the energy billed, or the revenue. This inattentiveness contributes to non-technical losses.

The personnel best qualified to detect metering problems are often the ones responsible for the faulty metering installation in the first place. In some countries, meter technicians and readers are complicit in meter tampering and bypass.

Meter Defects

Real-time two-way communications offered by AMI allow a utility to detect meter defects that might degrade to failure before the utility could learn about them from manual meter reads at intervals that are often as long as six or twelve months. Furthermore, there is evidence that meter readers miss some amount of meter tampering.[47] There are instances when distribution utilities have discovered meter tampering when deploying AMI that had not been reported by meter readers.

Need for On-site Inspections Post-AMI Deployment

Periodic on-site visits by meter inspectors carefully trained to know what they are looking for are an essential tool in the detection of theft in a post-AMI environment. It is good practice to visit randomly and inspect meters on a recurring basis. Some utilities plan such inspections on a 5-year cycle.

Customers who engage in diversion activities usually act to prevent access for meter reading, and procedures to require and enforce inspection are essential. Traditional meter readers may not be trained for new, more creative methods of energy diversion and must be schooled to recognize the sophisticated tampering methods that may follow the deployment of AMI. In addition, it should be noted that with advanced metering technology, various system abnormalities can resemble power theft. Thus, the staff of revenue assurance departments must have a higher level of training, technical know-how, leadership, judgment, and inquisitiveness.[48]

Supplemental, Consolidating Superseding and Replacement Testimony of James Teeter, SGD&E before the CPUC. March 28, 2006.

[47] In an extensive study undertaken in the Merseyside area over a five-year period, Revenue Protection staff acted as meter-reading staff and gained valuable intelligence. It became apparent that meter readers were poor at recording signs of interference with, say, only 1 in 15 of them providing reliable reports. *Theft of Electricity (Illegal Abstraction)*, Comments and Observations, Terry Keenan, Senior Manager, Manweb, Comment on Ofgem's Theft of Electricity and Gas Consultation Document.

[48] *Pilferage of Electricity—Issues and Challenges*, G. Sreenivasan, Assistant Executive Engineer, KSEB; guest faculty, Engineering Staff College of India, Hyderabad.

The transformation from "meter reader" to "meter revenue protection agent" is a core change in the evolution from traditional meter reading to AMI.

> "The old-fashioned methods are dwindling."
> Ron Jones, Residential Meter Services Manager, JEA

Meter Readers

Meter readers read electric, gas, water, or steam consumption meters and record the volume used. They serve both residential and commercial consumers. The basic duty of a meter reader is to walk or drive along a route and read customers' consumption from a tracking device. Accuracy is the most important part of the job, as companies rely on readers to provide the information they need to bill their customers.

Other duties include inspecting the meters and their connections for any defects or damage, supplying repair and maintenance workers with the necessary information to fix damaged meters. They keep track of customers' average usage and record reasons for any extreme fluctuations in volume. Meter readers are constantly aware of any abnormal behavior or consumption that might indicate an unauthorized connection. They may turn on service for new occupants and turn off service for questionable behavior or nonpayment of charges.

Median annual earnings of utility meter readers in May 2006 were $30,330. The middle 50 percent earned between $23,580 and $39,320. The lowest 10 percent earned less than $18,970, and the highest 10 percent earned more than $49,150. Employee benefits vary greatly between companies and may not be offered for part-time workers. If uniforms are required, employers generally provide them or offer an allowance to purchase them.

Tasks

- Read electric, gas, water, or steam consumption meters and enter data in route books or hand-held computers.
- Walk or drive vehicles along established routes to take readings of meter dials.
- Upload into office computers all information collected on hand-held computers during meter rounds, or return route books or hand-hand computers to business offices so that data can be compiled.
- Verify readings in cases where consumption appears to be abnormal, and record possible reasons for fluctuations.
- Inspect meters for unauthorized connections, defects, and damage such as broken seals.
- Report to service departments any problems such as meter irregularities, damaged equipment, or impediments to meter access, including dogs.
- Answer customers' questions about services and charges, or direct them to customer service centers.
- Update client address and meter location information.
- Leave messages to arrange different times to read meters in cases in which meters are not accessible.
- Connect and disconnect utility services at specific locations.

Work Activities

- Documenting/Record Information—Entering, transcribing, recording, storing, or maintaining information in written or electronic/magnetic form.
- Collect Information—Observing, receiving, and otherwise obtaining information from all relevant sources.
- Communicate with Supervisors, Peers, or Subordinates—Providing information to supervisors, co-workers, and subordinates by telephone, in written form, e-mail, or in person.
- Process Information—Compiling coding, categorizing, calculating, tabulating, auditing, or verifying information or data.
- Work Directly with the Public—Dealing directly with the public. This includes contact with customers, representing the organization to customers, the public, government, and other external sources. Information can be exchanged in person, in writing, or by telephone or e-mail.

Bureau of Labor Statistics, U.S. Department of Labor, *Occupational Outlook Handbook*, 2008-09 Edition.

Revenue Protection: Transition from Traditional to AMI

The first step in transitioning from traditional meter reading to remote was AMR, which replaced meter readers with remote meter reading via one way communications. The primary driver for this was savings on meter readers. This introduced difficulties with respect to theft detection. These difficulties were overcome with the evolution from AMR to AMI. AMI, coupled with MDMS, offers considerable advantages with respect to theft detection and the reduction of non-technical losses.

When AMR was introduced, there was an expectation that revenue protection would benefit greatly, and the need for revenue protection analysts and investigators would be greatly diminished. Tamper flags would be the solution. This did not prove out during large-scale deployment. In fact, AMR produced a flood of tamper flags that had the practical effect of being impossible to manage and, thus, being ignored. Except now, the "eyes in the field" were gone.

Most AMR meters have revenue-protection-related features that are useful for detecting novice tamperers, such as reverse rotation (meter being inverted by the customer) and magnetic presence (external magnets placed on meter in an attempt to reduce its registration).

However, there are limitations to AMR's ability to detect theft by experienced or professional tamperers who seek to defeat the system by installing taps ahead of the meter (for example, masthead), limit the ability to detect "last gasp" while installing bypass behind the meter, or using conventional tactics to slow disk rotation on retrofitted meters. Of course, stolen meters placed in-service by customers are difficult to locate.

Tamper Flag Problem

Several companies that have installed large-scale AMR have experienced problems with tamper flags. AMR has functionality for determining valid flags, but AMR supplies more information than utilities are able to monitor. There are problems with tamper data because of volume and the number of variables that must be taken into account for validation and separating the "urgent" and "genuine" interference cases from false alarms and technical faults. Utilities had to develop their own algorithms for dealing with this.

Further, AMR is not able to cover the types of theft that tamper flags do not report. It cannot detect diversions where the meter is bypassed completely (by "tapping" into the cutout or the wiring from it ahead of the meter). There is no way of detecting this, other than from analysis of consumption. Additionally, AMR is not able to monitor consumption and detect abnormalities which might be due to theft.

The solution to this is offered by AMI and MDMS.

The limited benefit of AMR for theft detection and problems with tamper flags pointed toward the need for MDMS, which only really came into its own later, when AMI was introduced. The awareness of data management requirements, after the experiences with AMR, was a major developmental turning point in the evolution of AMI applications for theft detection and non-technical loss reduction.

AMI provides information for detecting certain kinds of losses, such as detecting recurring tampers from upside-down meters and dial tampering, site and installation diagnostic problems, consumption on inactive accounts, and detailed data for trends and comparisons. However, AMI offers little or no protection from "one-time tampers" (adjustment screws, register tampering, magnetic circuit alteration, electrical circuit alteration or alternations external to the meter, magnets, disk "pinning", stolen meters and, most obviously, taps and jumpers.) These can only be detected using customer modeling (MDMS) and other revenue assurance tools as part of pro-active revenue assurance programs and systems, staffed by well trained and knowledgeable people.[49]

AMI provides a valuable tool to help utilities reduce lost revenue in each one of these areas, but AMI "... is only a tool—it must be coupled with *systems, people, and experience*."[50]

The transition in the detection process from traditional to AMI is summarized in Table 2-1.

Table 2-1
Comparison of Detection Process

Comparison of Detection Process
Traditional vs. AMI

Detection Process: Traditional	Detection Process: AMI	Change
Meter readers	Solid-state meters	Improved reading accuracy
Tips/utility hotline	Remote meter reading	Eliminates need for meter reader
Meter-reading reports	Two-way communications	Permits more frequent readings
Statistical analysis	Remote diagnostics	Discovers malfunctioning meters
Proactive sweeps	MDMS	Supports enhanced customer service
Collateral investigation	Meter revenue protection agents	Meter Audits

Transition to Revenue Assurance

In the 1970s and 1980s, these activities were called "current diversion." In the 1990s, they were called "revenue protection." Today, the preferred term is "revenue assurance." Revenue assurance conveys the full meaning of its role in a distribution utility, namely assuring that all the revenue owed the utility is collected.

Revenue assurance includes the following:

- Theft detection and follow-up
- Metering mistakes—for example, malfunctions, meter constants, and billing errors

[49] One study reported an average accuracy of 35% using AMI flags with consumer models. This is much better than AMI flags alone (4%) and better than customer models alone (29%) and is considered a very good "hit rate." *Revenue Protection and AMI Come Together*, Ed Malemezian. June 25, 2007.

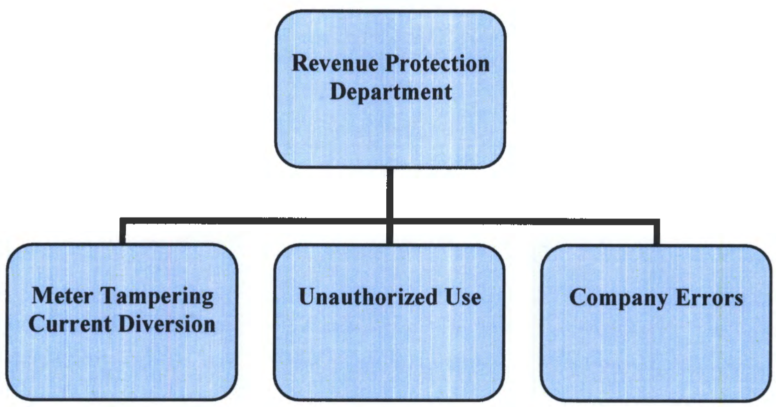
[50] *AMR Tamper Detection—The Good, the Bad, and the Possibilities*, Ed Malemezian

- Consumption on inactive accounts
- Collections

Revenue Protection Department

As revenue protection transitioned to revenue assurance, so did the responsible department and staff. The responsibilities remain the same, namely personnel training (mostly meter readers), receiving information on electricity theft from customers and staff, analyzing consumer load profiles for drastic changes compared to past trends, assessing charges for electricity theft and equipment tampering, and—if necessary—prosecuting clients who endanger themselves or field staff. The main source of information that utilities traditionally use to detect and prevent electricity theft is the meter-reading staff.

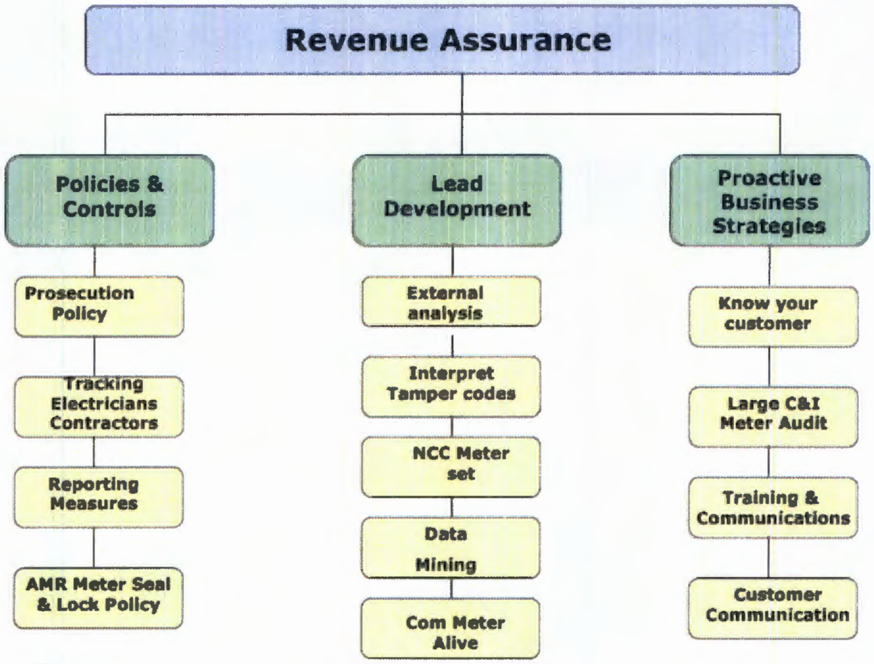
The traditional organization for discharging these responsibilities is illustrated in Figure 2-1. The three major areas where revenue (non-technical) losses were discovered by the Revenue Protection Department were meter tampering and current diversion, unauthorized use, and company errors.



Source: IURPA/WSUTA Conference, Las Vegas, Kurt W. Roussell, Revenue Protection, WEC.

Figure 2-1
Revenue Protection Department

Revenue assurance, on the other hand, is a term that describes the revenue security function as performed with AMI / MDMS. The new Revenue Assurance Department does not rely on manual meter readers—the "eyes in the field." Rather, there is a heavy reliance on policies and controls, lead development using analytical data and customer profiles, and proactive business strategies that include meter audits and customer communications. Meter readers are not absent from this department, but they are no longer depended on so extensively. Rather, revenue assurance with AMI relies heavily on MDMS, analytical tools, and analysts.
The organization of a typical Revenue Assurance Department under AMI is shown in Figure 2-2.



Source: NSTAR

Figure 2-2
Revenue Assurance

Revenue Protection Using AMI and MDMS

The AMI data collection front end detects and reports unexpected usage patterns. Typically, consumption profiles are established for each meter through automatic assignment of profiles using CIS supplied data and manually assigned profiles for specific or temporary situations. Each profile can consist of one or more checks. These checks can be enabled and disabled by the time of the year. They can be used to find diversions for monitoring seasonal meters. Drops in usage can be correlated by power outages for each meter as compared with other meters on the same transformer. All of the applicable checks need to be flexible enough to allow assignment of predetermined percentage changes in consumption, with day of the week and date range selection set up as required for each profile.

The Meter Data Management System (MDMS) receives additional information to aide in more filtering. Typically weather data, utility work order tickets, account status, and limited demographic data are brought in to aide in the filtering. Monthly and daily consumption data are collected and compared on a regular basis against profiles established for each customer. This data can be normalized by weather and other variable parameters. Effective usage is compared against baseline usage to generate candidate lists. These lists are then further filtered by additional information from tamper flags and more advanced consumption patterns to develop suspect lists. The suspect lists are organized and sent to the field for investigation. Various tools are often provided to drill down by customer and groups of customers.

The availability of interval data raises the bar to yet a higher level. Tools to compare actual interval usage against expected interval usage provide a much better picture in spotting the outliers. Advanced statistical techniques are used to generate appropriate algorithms that analyze the data. Science and art come together in making a success of this. Statistics also can be helpful in establishing confidence levels of the suspect lists, allowing the lists to be cranked up or down to match the availability of investigators to do the follow-up work.

Tests by transformer and geography provide another view of customer consumption patterns. When a utility utilizes account-to-transformer mapping, it allows the comparison of usage across similar homes served by the same transformer to look for low usage outliers, and to correlate changing usage patterns with blinks, reverse rotation, or other events. This mapping also enables comparison of transformer load to aggregated usage, if the utility installs additional interval meters upstream of the utility transformers. When meter data is supplemented with data from other sources, more views and points of comparison can be created. Examples include creative mining of other CIS fields such as the SIC Code or Customer Name to find groups of customers with similar names.

The Revenue Protection application receives all relevant data from the utility CIS, historical and present temperature data from an internet based source, triggered flags from the AMI tamper database, geographical information from external sources, SIC codes and NAIC codes from CIS, demographic data from paid or public sources, operating hours from public sources and feet-on-the-ground research, as well as daily and interval consumption data from the utility AMI or MDM systems.

Profiles and consumer models are built from sets of flexible rules. These are assigned to each account and analyzed on a regular basis. Tools include the ability to drill down by customer or group and to score each deviation from expected consumption patterns by numerous methods. Candidate lists and suspect lists are managed, and feedback is provided for both tracking results and improving the process.

Revenue Protection and AMI Come Together, Ed Malemezian. June 25, 2007.

MDMS Theft Reports

With the advancement of AMR/AMI, the traditional approach of identifying potential theft with a meter reader's visit to the site is becoming obsolete. Aided by MDMS, data analysis provides leads based on usage patterns and other data.[51] This is proving to be an effective approach to identifying theft.[52]

MDMS is used to turn AMI data into leads that can be followed up by revenue assurance teams. MDMS provides "automated exception processing" reports. An exception is when the system sees an event or data circumstance that it is not expecting. Examples with revenue-assurance relevance include meter readings that show lower consumption than expected, meters that do not report any consumption, and readings that show power being used at a supposedly vacant premise.

"Plus or minus 20" reports look at accounts where consumption has gone down by at least twenty percent. Data is reviewed over a thirteen-month period, ensuring that the information reflects seasonal usage patterns.

Another approach looks for unusual usage patterns, such as usage that drops off substantially on weekends. Through the MDMS, utility managers can compare unusual usage reports with power-outage and restoration reports that narrow down dead-end leads. This lowers the cost of collection.

Examples of Reports Using AMR/AMI Data[53]

- An "unplanned outage" report spotlights accounts with more than 10 outages in 30 days. About 40 percent of PECO's theft detection stems from this report.
- A "billing window" report detects meters turned on or off close to the billing period, indicating attempts to force low-balled estimates or pay for only a few days' worth of consumption. This report pinpoints around 35 percent of the utility's theft.
- A "reversed meter" report finds power-out and power-up messages that occur in quick succession if the customer unplugs the meter, then plugs it in upside down to make the register run backward. About 20 percent of PECO's theft shows up via this report.

[51] AMR / AMI tamper indications are analyzed with detailed consumption data, outage information, tickets from work order systems, and numerous external demographics. Advanced analytics are used to establish baseline patterns and profiles for customer accounts. Outliers can easily be identified and followed-up according to procedures established by the revenue assurance department.

[52] For example, at NSTAR, revenue protection billings increased more than 130 percent, while the cost per case processed decreased by 25 percent. The improvement was due to leveraging the lead generation partnership and streamlining the process with automated reports, fewer handoffs and triage of theft cases. *Reducing Revenue Leakage*, Penni McLean-Conner, NSTAR. Electric Light & Power, July 2007.

[53] *Deputizing Your Data: AMI for Revenue Protection*, Betsy Loeff, Electric Power and Light.

AMI Remote Service Disconnect

In certain instances, utilities incur losses when customers leave without disconnecting. In these cases, the utility has active accounts without contracts. Oftentimes, it would take utilities a minimum of thirty days to find active accounts with no contract. This produces non-technical losses.

With AMI, service cut-offs can be "virtual," without dispatching a field service technician to the site. Instead, the utility takes a reading through the AMI system, sends a final bill to the departing customer, and leaves the premises ready for the next resident.

Sometimes the new resident does not call to set up an account after moving into a house or apartment. In these instances, a consumption threshold is set up. Once the threshold is surpassed, the MDMS automatically generates an order for a field service technician to shut off service.

Key Attributes for Revenue Protection—AMI + MDMS

Advanced Meter Infrastructure

- Full two-way communications
- Advanced meter capabilities with extensive diagnostics
- Exponential increase in meter reads and meter data
  Example (500,000 meters):
  1 monthly read = 500,000 reads/month
  1 daily read 500,000 reads/day, 15 million reads/month
  1 hourly read 12M reads/day, 360 million reads/month

Meter Data Management Systems

- Systems to create reports that analysts/investigators can use to research, investigate, and take corrective action
- Energy Diversion will become more innovative with smart metering (without manual meter reading). Data and analytical tools must be used to "outsmart the thieves"

Pros

- Better knowledge of unbilled revenues
- Notification of illegal reconnects
- Ability to examine consumption patterns from daily read information
- Ability to examine 15-minute interval data

Cons

- Loss of regular field visits to examine metering equipment
- Inability to determine connections ahead of the metering scheme
- The meter will tell you only what it sees—not what it doesn't see
- Unless additional services are known, unmetered (unbilled) revenue can occur for years
- The combination of these factors along with the rising cost of energy increases the potential for revenue loss significantly

Source: *Various Applications of Electric Metering & How They Relate to Revenue Protection*, Guy Cattaruzza United Illuminating NURPA. September 19, 2007.

Billing and Customer Service

Along with theft, the billing and customer service problems encountered by traditional manual meter-reading operations are contributors to non-technical losses.

Traditional Billing System[54]

Currently, meter readers travel to customers' meters each month to collect customer usage information (meter reads) with a hand-held data collection device.

These meter reads are used to prepare monthly bills. After the meter-reading route is completed, the customer's meter reads are transferred from the hand-held device to the customer information system. This data transfer must be done at a meter-reading base location. Back-office billing systems then perform a series of data validation routines that will, if warranted, automatically trigger a pre-billing review that may result in bill adjustments. The largest number of bill adjustments is due to meter-reading error.

When customers move from one residence or business to another, field service personnel must visit the meter and complete a "close order" or a "change of account" order to obtain the "end read" for the departing customer and a "start read" for the new customer. A certain number of these orders are "revert to owner" reads where service is left on for the convenience of property owners or managers when a tenant moves. Also, when meter-reading errors are suspected, field service must perform a "read verify" order at the customer's meter.

Billing System with AMI

AMI eliminates field visits as part of the billing process. Instead, utilities obtain meter reads electronically on the date a customer desires rather than on a service order schedule, which is subject to delay due to workload constraints. This reduces error and, thus, non-technical losses. It also improves customer service.

To prevent billing errors, once meter data is captured the billing system performs a series of billing edits prior to sending the customer bill. Despite comprehensive edits, some billing adjustments are required after bills have been sent. Other anomalies (billing exceptions) also are detected after completion of the billing cycle, such as meters in "off" status but registering consumption (OBR), meter failures, and unauthorized energy usage theft. With AMI, many of these billing exceptions will be eliminated and others will be detected more quickly, thus reducing non-technical losses.

Estimating

Estimating is one of the defining issues for which AMI offers a solution and contributes to the reduction of non-technical losses.

[54] *Meter Reading and Customer Service Field Functions, Safety, Billing and Revenue Protection*, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, Chapter 3, Prepared Supplemental, Consolidating Superseding and Replacement Testimony of James Teeter, SGD&E before the CPUC. March 28, 2006.

The vast majority of utility customers receive a monthly visit from their utility's meter reader. This meter reader visually reads the electric and/or gas meter, then forwards that information to the utility's billing office to generate a monthly consumption bill. If the meter reader is unable to access the meter,[55] most utilities will proceed to estimate the electricity consumption based on previous usage and recent weather patterns. They will then use that estimate as the basis for the next bill.

Exception reports are another area where estimates are made. After data are collected, they are analyzed, looking for exceptions such as missing reads, zero consumption, idle with consumption, out of range readings, and negative consumption. These transactions are placed in an exception file for review. Actions taken by revenue protection to correct the exceptions include reading, re-reading, checking for malfunction, checking for tampering, or accepting the read and estimates.

It is not uncommon for utilities—particularly those in higher-density urban areas—to estimate ten percent, twenty percent, even thirty percent or more of the meter reads each month for billing purposes. This practice leads to inaccurate billing, increased customer complaints, and higher costs for utilities to investigate and resolve those complaints.

AMI Solution to Estimating

AMI provides accurate, timely, and reliable information about energy use and demand that offers a solution for estimating.

AMI minimizes meter access problems, limiting them to meter installation and inspection upon suspicion of tampering or diversion. AMI eliminates estimated reads and improves meter-reading accuracy, which results in improved billing accuracy, fewer customer complaints, reduced call center traffic, and improved customer service.[56] Further, AMI reads remotely interrogate meters daily, rather than monthly. This identifies bad meters more quickly and avoids much of the estimating.

Thus, AMI offers a solution to estimating, which contributes to the reduction of non-technical losses.

Security

AMI avoids the security risk of giving keys and access to premises to meter readers. This is a concern of high importance in these security conscious times.

[55] A meter cannot be read when it is located in the basement and the consumer is not home; the yard is fenced with a locked gate and a dangerous animal in the yard; customers are threatening or hostile; extreme weather; or when the meter is dead, damaged, or missing.

[56] *The Critical Role of Advanced Metering Technology in Optimizing Energy Delivery and Efficiency,* A Report to the U.S. Department of Energy, Itron. October 2005.

AMI + MDMS Solution: Importance of Information Technology

A comprehensive revenue assurance program is based on AMI and MDMS.

This constitutes a "holistic approach to revenue recovery"[57] that combines expert analytical resources, data analysis software, internal utility customer asset data, and external data sources. This involves identifying data flow requirements and providing solutions to ensure timely and accurate billing. This requires the effective integration of AMI and MDMS with existing data systems in the utility.

Information Technology Integration

IT integration is a major participant in the transition from traditional meter reading and revenue protection methods to AMI and comprehensive revenue assurance programs. It's importance is underscored by the level of investment in most AMI programs. Indeed, back-room office applications are a large portion of the total AMI investment, ranging from a low of 5% to over 30%. IT integration is essential to the management and reduction of non-technical losses after the transition to AMI.

IT heavily influences the success of the AMI program and the integration of information systems using new MDMS that is essential for the success of the AMI program. The IT integration plan includes five major systems:

1. Meter Reading
2. Meter Inventory Management
3. Work Order Management
4. Customer Information
5. Revenue Assurance

Integrating these systems is a substantial and complicated task. This requires a high level of commitment from IT stakeholders.

When AMR systems were installed, primarily for savings in manual meter reading, IT integration was not a priority. However, when the data flows (such as tamper flags) became overwhelming, utilities needed applications to manage them. These were often provided through *ad hoc* custom programs developed internally by IT departments.

For this reason, it is advisable to include IT stakeholders from the beginning when making the transition to AMI. The commitment should be in terms of the project, resources, change management, and setting expectations for results. Commitment from IT stakeholders dramatically affects the success of the transition and results in reducing non-technical losses, both at the time of installation and throughout project life.

[57] *Discovering Unaccounted-for Energy with the Revenue Assurance Service*, Patty Seifert, Revenue Assurance Product Manager, Itron. 2007.

Revenue Assurance and IT Integration

The advent of AMI brings a total change to the conduct of revenue protection. If not preceded by AMR, the most obvious change is the elimination of manual meter reading as the primary method of data collection on meter tampering and theft.

Without the benefits of manual meter readers, revenue protection must supplement AMR/AMI with meter data management systems to compensate for the loss of functionality previously provided by meter readers. This involves integrating MDMS into the customer information system. The combination of data from AMR/AMI, MDMS, and customer information system (CIS) can be used to generate leads and profiles for target areas and customers.

Revenue Assurance, Metering & IT business units must come together early, prior to the deployment of AMI, to form a team separate from the deployment itself to develop a Revenue Assurance Transition Plan.

Transition to AMI—Information Technology
Issues that Impact Revenue Protection

- System reliability, data backup and disaster recovery
- Reporting / monitoring capabilities
- End of day vs. real-time 24/7
- Exception handling
- Secure access
- Customer information system integration
- Work order file definitions
- Customer data file management
- Meter reading / billing window ("blackout")
- Test and validation of upload/download processes
- Meter-reading systems integration
- Migration path
- Project size, schedule,and budget

Bob Donaldson, PE, PMP Progress Energy Carolinas Project Manager, Mobile Meter Reading.

Theft and Enforcement

New Methods of Theft

A major risk of realizing the full benefits of AMI for revenue protection is posed when customers learn to divert energy in new, unknown ways. Given historical data from AMR installations, this risk does not appear too great. Also, AMI endpoints have software and tamper sensors that are more sophisticated at detecting theft. Enhancements to back-office systems with new algorithms and heuristics to identify new types of theft are continuously being developed. Nonetheless, most certainly the ingenuity of a few customers will lead to some new types of theft. Distribution utilities need to be alert to new possibilities for theft and take them into account in their revenue protection strategies.

"The western countries and India have treated this as a criminal offence. But crooks always have the ability to keep one step ahead of the theft detection system. They stay in business purely through their flair to overcome any challenge that comes their way. They will find ways to be ahead of any anti-power theft detection system and will try to hoodwink the vigilance wing. Gone are the days of crude mechanical ways to tamper with the meter or divert electricity from main line. The R&D of electricity theft is moving faster than that of the best metering mechanisms, which was revolutionized with the advent of ICs and programmable logic circuits. Sharp minds frame laws and invent technologies; sharper minds find loopholes in it. Now power theft using the remote sensing devices, tampering of crystal frequency of integrated circuits; theft using harmonics, etc. have been developed."[58]

Customer Perception and Motivation

Far from deterring customers from theft, some distribution utilities have reported an increase in occurrences after AMI installation. Once some customers are aware that meter readers are no longer calling, they think that there is less likelihood of being caught. The technical aspects of dealing with advanced electronic metering are no deterrent. There is a wealth of data available on the internet on how to interfere with meters. Even consumption monitoring is not the full answer. Clever thieves know that they should gradually reduce consumption over a period to avoid detection by the relevant "filters."[59]

One new class of customers that are wittier than thieves in the past and have new motivations are "grow operations." These customers—the illegal growers—are motivated not by saving on electricity, but by not being detected as customers. This is a major source of non-technical revenue loss in Canada and parts of California.

AMI can be helpful in detecting theft by this new class of customer. An example from Sacramento, California, is noted in the following quotation.

"Energy theft is not high at all, but we have experienced a significant number of 'grow houses' springing up in the area. We see AMI assisting us in finding these houses from a transformer load perspective—it will tell us that we're sending out X amount of kWh and only billing for Y amount, and alert us to a potential problem."[60]

AMI systems that are deployed at the substation transformer and feeder level are particularly effective in detecting these thefts.

Enforcement

As the attention of regulatory bodies and the public is drawn to energy theft, new and better methods for detecting and finding instances of theft will be called for. AMI has much to

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[58] *Pilferage of Electricity—Issues and Challenges*, G. Sreenivasan, Assistant Executive Engineer, KSEB; guest faculty, Engineering Staff College of India, Hyderabad.

[59] OFGEM *Consultation on Domestic Metering Innovation, Response by the United Kingdom Revenue Protection Association*, Version 3 (final). March 15, 2006.

[60] Erik Krause AMI project manager, SMUD

contribute to these methods. AMI offers significant tools to expedite both discovery and resolution of theft cases. It can be used to build intelligent databases for identifying trends and potential factors influencing future theft strategies and targets. This is an ongoing endeavor.

AMI makes more aggressive enforcement programs possible by 1) identifying high-probability targets for investigation and 2) gathering more evidence and constructing more convincing cases.

Meter bypassing can be proved only when it is observed at the time of inspection. The consumer can erase all traces of theft if the inspection is known in advance. This is a significant problem in many developing countries. AMI can help identify customers and locations with a high probability of meter tampering and diversion, thereby increasing the chances to observe theft.

Investigating Power Theft

Utilities often initiate probable cause investigations after a meter reader detects a broken seal or other indications of tampering. The meter reader reports the condition to a supervisor or power theft investigator, who then conducts the investigation. At this point, some utilities will contact their local law enforcement agency and an officer will accompany the utility investigator during the initial investigation.[61]

If the investigator finds evidence of tampering, evidence is collected and reports are prepared. The utility maintains the evidence and provides supporting documentation.

Evidence and Prosecution

Before a utility can file charges against a potential suspect, it must gather the following as evidence, documents, and appropriate statements:

- Tampering devices—These could include straps behind the meter, wires used in a bypass system, or other tampering devices or equipment relevant to the case.
- Meter report—This report shows that the meter was operating correctly when installed and demonstrates how the particular tampering method used would have affected the metering of electricity.
- Witnesses—These are witnesses who provide testimony. They include the meter reader who initially detected the possible diversion, the utility investigator, and the police officer who conducted the investigation.
- Account billing history—This report illustrates the time the theft began and the amount and cost of the stolen electricity.

Without manual meter reading and field service personnel, AMI and MDMS are now expected to provide much of the required documentation for theft investigations. With AMI, this documentation can be much more detailed and present more persuasive cases. For example, most utilities have account billing histories on each account's consumption and billing records on

[61] *Power Theft: The Silent Crime*, Karl A. Seger, and David J. Icove, FBI Law Enforcement Bulletin. March 1988.

a month-by-month basis. AMI provides information on a daily and hourly basis. This is necessary to detect more sophisticated theft techniques, such as "on offs" during the day.

The burden of this documentation is one reason that utilities prosecute only about 10% of cases.[62] The burden can be lessened considerably by using the data that AMI generates and the ability of MDMS to organize it into useable formats for preparing complaints for use by prosecution.

Installation Effect

AMI deployment requires replacing legacy meters with new meters that include two-way communications and diagnostic capabilities. This is a one-time opportunity to significantly reduce non-technical losses due to meter defects, theft, and billing.

> "AMI provides the opportunity for a 100% clean sweep."
>
> Ed Malemezian

Meter Defects

Although theft is a major source of non-technical losses, a significant percentage of non-technical losses arise from factors that utilities can control, especially those related to meter damage, failure, and errors.

"Although, numerous published papers imply that all revenue losses are a result of customer mischief, this is far from true. This project found that, at least in the small industrial and commercial sector, utility operations themselves are responsible for the larger share of lost revenue. Equipment failure, non-malicious equipment damage, incorrect meter constants or 'CT' ratios, meters in need of recalibration, etc. all contribute to revenue loss."[63]

These are largely due to problems with maintenance issues of electromechanical meters nearing the end of their useful life and the tendency of electromechanical meters to run slower as they age. The replacement of legacy electromechanical meters with electronic metering, as part of AMI deployments, should substantially mitigate this source of loss.

The installation of AMI itself, and the replacement of obsolete meters, will contribute greatly to the discovery and remedy of this source of non-technical loss.

A large proportion of meter problems, and nearly all of the failures, will be remedied by a competent AMI deployment that re-installs all meters. Finally, for the life of the AMI system, the AMI-equipped meters will detect and report many types of energy diversion and meter tampering.

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[62] Ed Holmes, Senior Consultant, Arnett Industries.

[63] *Revenue Metering Loss Assessment*, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA, Worcester, MA, South Carolina Electric & Gas Co., Columbia, SC and Baltimore Gas & Electric Co., Baltimore, MD: 2001. 1000365.

Some existing meters may be within the permitted accuracy tolerances and still under-register consumption. This is so small that it is not cost-effective to change the meters on an exception basis. However, the AMI deployment replaces every meter anyway, and brings aggregate meter plant accuracy very close to 100%. This benefit will be long-standing because solid state meters have no mechanical wear or friction and do not slow down over time. Sometimes dead meters are found during meter replacements. "Dead meters" are not caught by "no consumption" reports because they usually occur on the percentage of meters that are not yet converted to automated metering.

Inspection

A full AMI deployment provides the opportunity to inspect, find, and correct tampering that has been in place for a long time—100% inspection. However, to be effective, AMR installers must be properly trained and incentivized to take the time required to discover, record, and report tampering.

The entire service entrance facility, not only meters, must be inspected. The importance of inspection to the reduction of non-technical losses is shown in the following statement.

"Utilities that take the time to thoroughly inspect the entire service entrance facility, as well as the meter and meter socket themselves, at the time of AMI equipment installation have the opportunity to minimize otherwise lost revenues."[64]

Some methods of energy theft, such as meter bypass, meters turned upside-down, and meters with drilled holes or adjusted dials, are not necessarily seen by meter readers during their monthly meter-reading cycle visits. Since AMI offers total meter replacement, almost all simple energy theft will be uncovered during the installation of the new meters.

Meter Change-outs

As the volume of AMI-related meter change-outs increases, timely synchronization of meter changes with customer account data becomes essential to help a utility avoid large numbers of billing system rejections caused by incorrect meter assignments. MDMS helps to minimize the number of incorrect and estimated bills that result from the change-out process, thus avoiding billing errors that can contribute to non-technical losses during AMI deployment.[65]

Billing Transition Period

When new meters are installed, a number of data elements must be recorded properly to set up the billing systems. Additionally, new data about meter communications are typically required (such as AMI communication module serial numbers). The installation of AMI offers the opportunity to consolidate databases from multiple sources into a fully integrated MDMS.

[64] Interview with Ed Holmes.

[65] This is particularly important with large-scale AMI deployments that can take from three to five years.

MDMS provides benefits to utilities during AMI implementation by helping to identify and track meter installation problems and verify that data received from endpoints is sufficient for customer billing. If installed as part of the AMI meter installation, MDMS can be used to process data for billing. MDMS can be used for validation, estimation, and editing in the billing process during installation. Interval data provided by AMI systems may have gaps and/or errors. The MDMS system can be used to fill in the gaps and correct the errors in the data.

The AMI installation period offers an opportunity to create customer profiles that compare usage patterns before and after AMI installation. The identification of possible theft in the past is an indicator of theft likelihood in the future.

GIS Mapping

AMI requires that meter asset data is maintained timely and accurately. Meter asset data, including meters and communication modules, must track assets from acquisition to inventory to field installation and provide accurate meter-to-customer and meter-to-network connectivity information. This often requires consolidating and enhancing existing meter applications, including those in meter test, inventory, AM/FM/GIS, and customer information systems. These issues must be addressed at the time the AMI system is installed.

Geographic information system (GIS) mapping during AMI installation provides a valuable resource for revenue assurance. AMI installation offers an opportunity to integrate a GIS system with the customer billing system. This is an effective tool for detecting theft at consumer, distribution transformer, and feeder or substation levels. Analysis of patterns of individual consumption over GIS can help in identifying the sources of theft.

Energy Diversion Program

Utilities can take advantage of the replacement of meters to refresh their energy diversion programs, as well as public awareness of the issues and penalties.

Distribution utilities that have some type of revenue protection program in place can update their program and institute more aggressive programs using a combination of the AMI, MDMS, and teams of newly trained field inspectors.

For distribution utilities that do not have an energy diversion program, AMI installation is an opportunity to institute one at low cost.

AMI Planning and Transition

The revenue protection department staff should be included in the AMI project team from the beginning of the planning process. These individuals can offer valuable insight on many pertinent issues, ranging from a customer's behavior to billing (the integration of databases in the MDMS) to collection. Most importantly, they have the experience to help train meter installation teams and monitor the testing and installation of the meters themselves. They are an important part of the transition to AMI. Their participation can contribute greatly to the realization of potential savings from AMI and the reduction of non-technical losses.

The transition itself—replacement of meters, analyzing customer profiles, testing, system development, algorithm development, and customer profiling—probably has the greatest impact on revenue security and the reduction of non-technical losses.

3
CHAPTER 3

AMI Technologies to Detect Non-Technical Losses

AMI offers many technologies for the detection and reduction of non-technical losses. These technologies can be divided into two main categories, hardware and software, as outlined in the following insert.

Hardware – metering technology

- Meter accuracy
- Tamper detection
- Remote testing diagnostics
- Remote connect/disconnect

Software-based applications and tools

- Meter data management systems
- Statistical analysis
- Geographical information systems

These technologies can be used alone or, preferably, in combination with one another for enhanced effectiveness and manageability.

In this chapter, these technologies will be discussed in the context of their relevance to non-technical losses.

Importance of AMI Technologies to Detect and Reduce Non-Technical Losses

The relevance of the technologies for the detection and reduction of non-technical losses is evidenced by the functions and uses that utilities consider most important as part of overall AMI deployment.

As part of the FERC report[66] on demand/response and advanced metering, FERC staff conducted a survey of utilities.[67] Respondents were asked how they used their systems and which functions

[66] Section 1252 (e) (3) of the Energy Policy Act of 2005 (EPAct 2005) requires FERC to prepare a report by appropriate region that assesses electric demand/response resources.

[67] *Assessment of Demand Response and Advanced Metering Staff Report*, Docket AD06-2-000. FERC. August 2006. In preparing this report, Commission staff developed and implemented a first-of-its-kind, comprehensive national survey of electric demand response and advanced metering. The FERC Demand Response and Advanced Metering

are provided by the AMI systems. Specifically, the FERC survey asked organizations that have installed AMI systems[68] to identify which of the following possible AMI features they used:

- Remotely change metering parameters
- Outage management
- Pre-pay metering
- Remote connect/disconnect
- Load forecasting
- Reduce line losses
- Price responsive demand/response
- Enhanced customer service
- Asset management, including transformer sizing
- Premise device/load control interface or capability
- Interface with water or gas meters
- Pricing event notification capability
- Power quality monitoring
- Tamper detection
- Other

The most often reported functions were "enhanced customer service," and "tamper detection." Figure 3-1 shows the results of the FERC Survey.

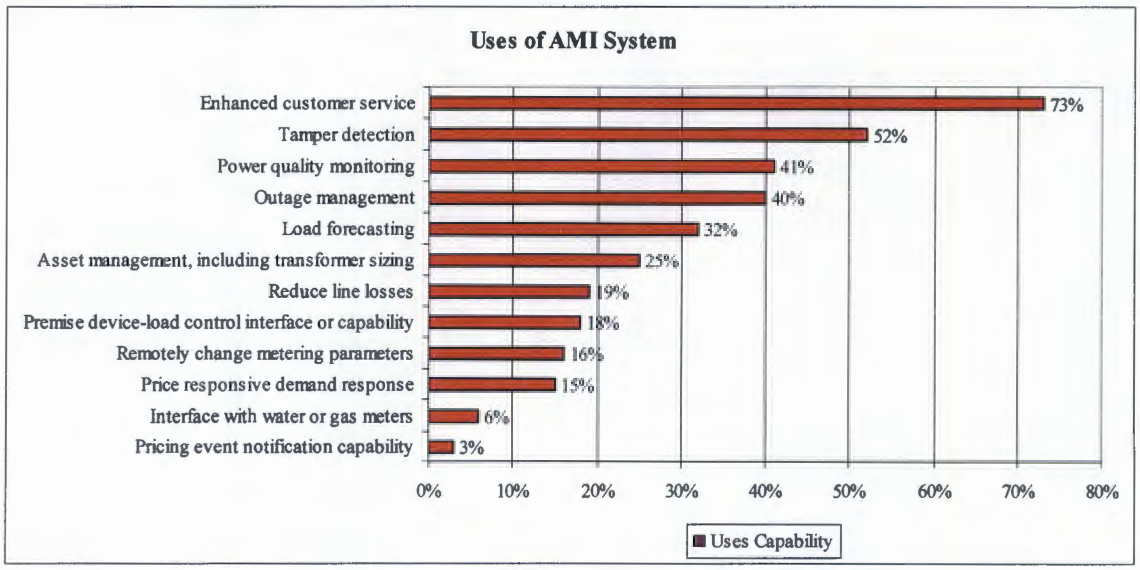

Figure 3-1
Uses of AMI System

Survey (FERC Survey) requested information on a) the number and uses of advanced metering and b) existing demand/response and time-based rate programs, including their current level of resource contribution.

[68] For purposes of this report, Commission staff defined "advanced metering" as follows: "Advanced metering 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."

The identification of these uses of advanced metering by utilities points to a number of areas related to the detection and reduction of non-technical losses. Recognition of these functions indicates the importance of non-technical losses to utilities as part of overall AMI programs. At minimum, it shows that AMI must deliver enhanced customer service and tamper detection:

> *Enhanced Customer Service:* The ability to offer ultimate customers the choice of bill data, additional rate options such as real time pricing or critical peak pricing, verification of an outage or restoration of service following an outage, more information to address a customer concern over an electric bill, reduced bill estimates when a meter read is not available, opening or closing of an account due to customer relocation without requiring a site visit to the meter(s), and/or more accurate bills.[69]

> *Tamper Detection:* The ability to detect the possibility that a revenue or billing meter has been tampered with, and to indicate a potential energy theft in progress, to be further investigated by the utility.

Theft at the Meter

There are two types of theft at the meter that contribute to non-technical losses: bypassing the meter and tampering with the meter itself.[70] The various ways in which this theft is done are listed in the following two inserts.

Installation Tampering

Line-side taps
- Weather-head
- Service entrance conductors
- Underground
- Switchgear / buswork / troughs

Bypass
- Jumpers in meter socket
- Close bypass device

Instrument transformer installations
- "Re-wiring"
- Shorting of current transformers

Meter Tampering

Internal to the meter
- Adjustment screws—one time
- Register tampering
- Magnetic circuit alteration
- Electrical alteration
- Dial tampering—Recurring

External to the meter
- Magnets—RC
- Hole in cover / disk "pinning"
- Upside-down meter
- Stolen meter

Internal physical tampering with the meter itself appears to be a less popular method of stealing energy than bypassing the meter or using diversionary taps installed ahead of the meter in the supply wiring.[71]

[69] AMI—through remote reading—allows for faster, more accurate accounts, reduces discrepancies, and through remote connect/disconnect allows for faster, more timely activation and deactivation of accounts. This translates to more revenue and fewer disputes.

[70] AMR Tamper Detection - The Good, the Bad, and the Possibilities, Ed Malemezian

Installation tampering and meter tampering should be kept in mind while considering the technology features described in this chapter.

Technologies

The uses of AMI technologies to support revenue assurance programs were discussed in the previous chapter. In this chapter, we shall focus on describing the technologies in terms of their characteristics and functionality.

Meter Features

Among the meter features used in AMI systems, those that are important for detecting non-technical losses are listed in the following insert.

[71] *Revenue Metering Loss Assessment*, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA, Worcester, MA, South Carolina Electric & Gas Co., Columbia, SC and Baltimore Gas & Electric Co., Baltimore, MD: 2001. 1000365.

Meter Standards and Features

Important for Detecting Non-technical Losses

Institute of Electrical and Electronics Engineers (IEEE)/ American National Standards Institute (ANSI) Standards

- IEEE 1701/ANSI C12.18 (1996)
  Protocol Specification for ANSI Type 2 Optical Port
- IEEE 1377/ANSI C12.19 (1997)
  Utility Industry End Device Data Tables
- IEEE 1702/ANSI C12.22 (1999)
  Protocol Specifications for Telephone Modem Communications

High-accuracy internal clock

Communications

- two-way communications
- communications functions that can be installed without disturbing metrology

Measurements

- power quality measurements: outage detection and duration; phase loss, sag, and surge detection
- storage capabilities for multiple sets of readings
- event log with circular memory buffer to store up to 100 events
- measure and display active energy delivered, received or net, or any two registers from delivered, received and net (kWh and kVAH)

Prepayment

- prepay functionality, including varying deductions per time-of-use scheduling, configurable emergency credit, and audible low-credit alarm

Security

- measurement technology that is immune to magnetic tampering
- record of programming changes, power outages, number of demand resets
- reverse disk rotation

Disconnect/connect

- disconnect switch controlled via software
- remote disconnect/reconnect switch

Tamper Detection

- tamper indications that can be communicated regularly through the communications system
- indicators include meter inversion, meter removal, and reverse energy flow
- tamper-resistance features that measure energy even if the meter is inverted and detecting when the meter is removed from a live socket
- increments a counter each time the meter senses reverse power flow
- power removal tamper (increments a counter each time the meter is removed from a live socket)

Hardware: Meter Requirements

Meter requirements will be discussed under four major headings:

1. Meter accuracy
2. Tamper detection
3. Remote testing and diagnostics
4. Remote disconnect / connect

Meter Accuracy

The accuracy of metering data is becoming increasingly important as advanced metering provides data that are integrated across many utility functions. The trend towards solid-state meters capable of delivering information for real-time use has increased both the visibility and importance of meter accuracy to distribution utilities, customers, and regulators. The increasing inaccuracy of legacy electromechanical meters as they age contributes to non-technical losses.

To evaluate the best metering platform for AMI, one utility performed a statistical study of electromechanical meter accuracy.[72] The results were as follows:

1. A thorough statistical analysis of electromechanical meter accuracy found that 20% of electromechanical meters have a high likelihood of under-recording usage by an average of nearly -0.8% (or 99.2% meter accuracy), with significant levels of variability in meter accuracy.
2. Service location (environmental factors), manufacturer meter serial number, and meter age were found to be reliable predictive factors of electromechanical meter accuracy.
3. The "accurate life" is about 25 years for most electromechanical residential meters and about 20 years for most electromechanical demand meters.
4. The volume of in-service meters recommended for replacement was highest for meters purchased from the late-1970s to the mid-1980s. Over 32,000 in-service meters recommended for replacement had an unknown purchase year and an average kWh composite meter error of -1.13%.

Meter Accuracy

Mechanical meters, in addition to being less accurate than solid-state electronic meters when new, fail as they age. Many meters eventually fail completely and register zero-use. Such failures often go undetected for a period of time because they are assumed to be caused by customer vacancy. Eliminating slow meters and other metering issues involving "lost and unaccounted for" energy use will result in accurate bills and assign payment obligations to those customers who use the energy rather than to all other customers.

Meter Reading and Customer Service Field Functions, Safety, Billing and Revenue Protection, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, SGD&E before the CPUC, March 28, 2006.

[72] *Metering Accuracy, Solid State Metering and the Electric Utility Enterprise Transformation*, Dave Mundorff, Entergy Corporation. September, 2005.

Tamper Detection

Tamper detection features that are important to AMI include the following:

- Reverse energy flag / reverse energy register
- Tilt switch
- Meter inversion
- Blink counter—no power to meter
- Magnetic sensors and diagnostics

These tamper detection features are described in the sections below.

Reverse Energy Flags
Reverse energy flags detect meters that have been turned upside down. In addition to the flag, some meters capture the reverse energy in a separate register. Other meters simply add reverse energy to forward energy, thereby accumulating total consumed. Theft is detected when the total no longer matches the meter dials.

Tilt Switches
Tilt switches detect meters that have been tilted from the normal position, usually around 50° to 70°. Tilt switches are prone to give false indications from vibrations. Meter removal is inferred when the tilt switch closes and a power outage detected after short time delay. Tilt switches, along with the outage detection, provide a reliable indication of meter removal. However, it must be noted that meter removal does not necessarily mean that tampering has taken place.

Meter Inversion
Meter inversion is inferred when meter removal has been detected.[73] In this instance, the tilt switch stays closed and power is restored, providing a reliable indication that the meter is running upside down. This also can generate a reverse energy flag.

Blink Counters
Blink counters measure increments for each interruption detected. A repeated number of interruptions can indicate tampering.

Magnetic Sensors & Diagnostics
Site and meter diagnostic sensors on solid-state meters (solid-state meters only; not meters with communication interface add-ons) detect meter wiring, instrument transformer, voltage, and current balance problems. Meter diagnostic flags detect internal meter malfunctions and tampering.

Reverse energy flags have proved effective in tamper detection. However, AMI generates a very large number of flags that must be sorted out. In many cases, the number of flags is overwhelming. Some of the flags are "false;" for example, magnet sensors generate many false flags.

[73] When the meter is pulled out of the socket and plugged back in upside down, the meter runs backwards and the kWh register goes down instead of up. The user leaves the meter inverted for a number of days to shave usage off the bill, and the meter is then reinstalled before a meter reading.

To be effective, tamper indicators must be filtered to spot trends and provide reliable comparisons.[74] Blink counts and outage flags must be compared against neighbors. Regular meter work, emergency work, maintenance, and repair work must be backed out of data on meter tilts, removals, and power outages. In other words, a system solution is required for these features to be utilized effectively by revenue protection departments.

Tamper Detection Features

Meters shall be able to:

- detect removal from its socket and generate a tamper event before it loses ability to communicate with the communications network
- detect voltage at the load side when the disconnect switch in the meter is open (for the purpose of detecting meter bypass) and generate a tamper event
- detect physical inversion and generate a tamper event
- detect physical tampering, such as, seal tampering, meter ring removal, case / cover removal, etc. and generate a tamper event
- transmit and locally log the following information (at a minimum) for each tamper event:
    1. Event Timestamp
    2. Tamper status (event type)
    3. Meter ID
- communicate tamper events to the Data Center Aggregator as soon as they occur (when possible)
- send meter tamper events with a higher priority than normal status messages
- store tamper events and transmit them when meter communications are re-established (if the meter is unable to communicate at the time the tamper event is detected)
- distinguish initial installation events and re-energize events (i.e. after an outage) from meter removal and reinstallation (potential tampering) to avoid transmission of non tamper related events.
- store tamper events until they are flagged for deletion once they have been successfully transferred to the Data Center Aggregator and 45 days have passed.

AMI Preliminary System Requirements, SCE. June 2006.

Testing and Diagnostics

Since AMI systems allow the reduction or elimination of meter service personnel and on-site visits, remote diagnostics are used to replace the meter reader's "eyes in the field."

Diagnostic features located in the meter typically provide measurements of parameters such as the following:

- Polarity
- Voltage deviation

[74] AMR Tamper Detection—The Good, the Bad, and the Possibilities, Ed Malemezian

- Inactive phase current
- Phase angle displacement
- Current imbalance
- Reverse energy

Service scan diagnostics read data on these parameters and current conditions at meter locations.

Results are reviewed by engineering staff who initiate an investigation, issue an instruction for meter change-out, or an investigation of the distribution line.

Service scans can discover open voltage test switches, current test switches left shorted, failed wiring on the meter harness from test switch to meter base or incorrect initial wiring, failed voltage transformers, and open distribution line fuses. All of these, including meter failure itself, contribute to non-technical losses.

The requirements for testing and diagnostics for meters and data center aggregators are shown in the following insert.

Testing and Diagnostics

Meter shall be able to:

- support a remotely or locally initiated meter test for communications connection status
- support a remotely or locally initiated meter test for energized status
- support a remotely or locally initiated meter test for load side voltage
- support a remotely or locally initiated meter test for disconnect switch status
- support a remotely or locally initiated meter test for internal clock time accuracy
- return results for all remote or local meter tests within 60 seconds
- Neighborhood Aggregator shall permit remote:
    1. status report (up / down)
    2. diagnostics
    3. link status report
    4. communications event log retrieval

Data Center Aggregator shall be able to:

- provide comprehensive remote testing and diagnostic capabilities for each system component (communications and meters) based on a (periodic) schedule or on demand. Remote testing and diagnostic alarm messages are to be considered high priority.
- remotely test meters for communications status, energized status, load side voltage and switch status on-demand.
- remotely test communications with external third parties.
- identify the probable cause of a communications failure within the AMI communications network.
- provide mechanisms for remotely correcting system/component problems, which at a minimum shall include the ability to remotely recycle (or restart) a component.
- log the results of all remote testing and diagnostics activities and any automatic actions taken based on those results.
- make the results of all received alerts and remote testing and diagnostic results available to authorized IT systems (e.g. MDMS, CSS, Work Order Tracking, etc.).
- have configurable alert levels and notifications based on the severity of a problem detected and the number of endpoints affected.
- classify specific testing/diagnostic results to either require or not require human intervention (configurable) in the determination of issuing trouble reports.
- detect if any network components are not responding within the following intervals based on the number of meters affected. (Estimate only; different network topologies will result in different values.)

    A) < 200 meters - next read.
    B) 200 - 1000 meters - within 6 hours
    C) 1000 - 5000 meters - within 1 hour
    D) 5k - 20k meters - within 15 minutes
    E) 20k - 50k meters - within 1 minute

AMI Preliminary System Requirements, SCE. June 2006.

Remote Disconnect / Connect

With solid-state meters being deployed as part of AMI systems over entire service territories, remote connect/disconnect features are attractive from service, operational, and economic points of view. The key driver for this change is that meter providers can integrate the disconnect/connect switch into the solid-state meter.

Remote connect/disconnect switches have traditionally been installed on electric meters for customers who either were consistently late on paying their electric bill or that lived in an area where people moved more frequently.[75] These classes of customers have a high incidence of non-technical losses with respect to non-payment of bills and errors in billing due to timing of disconnects / connects (stop time for one customer; start time for another).

[75] This is not an insignificant class of customer. For example, customers in SCE's service territory move at a rate of one in every four customers per year. (Paul DeMartini, Director AMI Program)

Remote Connect/Disconnect Features

Meter shall be able to:

- accept scheduled service disconnect/ reconnect
- remotely disconnect/ reconnect on demand
- remotely disconnect/reconnect according to utility pre-configured rules
- detect duplicate service disconnect/ reconnect events and ignore the duplicate events (e.g. Meter is already on -- reconnect event accepted with no action taken)
- cancel or update/reschedule scheduled disconnect/ reconnect events prior to their completion
- send a meter read and acknowledgement to Data Center Aggregator upon a successfully completed or failed electric service disconnect/ reconnect event
- enable an SCE Employee working on-site at the customer premise to be able to physically operate its service disconnect/ reconnect switch at any time. 24 hours, 7 days a week, 365 days a year
- support an external authorization/ authentication routine (i.e. by remote systems or field tool) to enable only active and eligible SCE employees to operate its service disconnect/reconnect switch on-site at the customer premise
- allow authorized SCE employee (while on-site at the customer premise) to operate the service disconnect/reconnect switch immediately (regardless of interval) or to schedule a connect/ disconnect for a future interval
- log date/time and status of attempts to operate the service disconnect/reconnect switch remotely or on-site at the customer premise. Log entries will include requesting user or system identity and authorization status
- remotely disconnected/reconnected on demand and have acknowledgement received by requesting system within 1 minute of request being initiated
- allow a reconnect event to occur following a disconnect event only after a configurable amount of time (e.g. at least 1 to 2 minutes) has elapsed since the disconnect event.
- Note: Should a disconnect event and reconnect event be scheduled to occur for the same meter on the same day, Meter shall log the events and automatically provide an on-demand read to the Data Center Aggregator without operating the disconnect/reconnect switch

AMI Preliminary System Requirements, SCE. June 2006.

Software-based Applications and Tools

To be effective, AMI tamper indicators need to be filtered to spot trends, outliers, and provide for reliable comparisons. Blink counts and outage flags need to be compared against neighbors. Normal meter and trouble work need to be backed out of meter tilts, removals, and power outages. Custom algorithms and a formal process are required to look at trends. Energy consumption needs to be compared—by individuals and by groups.

To be most effective, AMI data needs to be combined with the following:

- Class of customer
- Geographical information
- Normalization for weather, occupancy, and other similar factors
- Customer's past history—family, friends, and other businesses
- Other utility usage—gas, water, cable
- Experience

Software-based applications and tools must be used to analyze the data that are delivered by AMI metering and communications technology to utilities—revenue assurance departments in particular. There are three major categories of software-based applications and tools that are necessary for AMI to effectively detect and reduce non-technical losses and maximize its impact on revenue:

1. Meter data management systems
2. Statistical analysis
3. GIS—at time of installation and for identifying locations for abnormal behavior

Meter Data Management Systems

Advanced metering delivers frequent interval data, which greatly increases the amount of information a utility will have about consumption. The volume, frequency, resolution, and type of data (for example, interval demand data, voltage, outage events, and meter tempering indications) delivered by AMI from meters are vastly different from manual meter reads and mobile (drive-by) meter-reading systems.

MDMS is used to manage the large volumes of meter data generated from AMI systems. MDMS is the software that accepts data collected from an AMR/AMI system, stores the data, and forwards the data to utility systems such as billing. MDMS is an essential tool for utilities that may have tens or even hundreds of thousands or millions of meters generating data that are gathered in multiple ways.

Data Collection and Analysis

While AMI monitors customer power consumption , MDMS uses the data collected for statistical analyses that generate standard reports, such as Hi/Lo reads with statistical process control charts, multi-day bad meter reads, zero usage day with non-zero average, and custom meter groups. These can be used to identify customer load changes that may be related to meter theft.

MDMS is used to develop actionable intelligence for use in revenue protection programs. MDMS receives revenue protection flags from the meters and compares them with usage trends, outage information, and service order/field work to determine which are actual revenue protection issues and which are false positives.

By relying on a central repository of historic meter data, analytics can pinpoint usage patterns that might indicate meter defect, meter tampering, or theft of service. If a customer's energy usage remains abnormally low during heat waves, cold snaps, or before and after outages, then the meter might be malfunctioning. If more energy is flowing past distribution points than is being billed for, then it's possible that someone is stealing service. Without meter data management, this type of revenue-assuring analysis is nearly impossible.

MDMS is used to validate data against theft indicators, automatically initiating appropriate alerts and tracking responses. MDMS is used to set threshold levels for usage on a premise-by-premise basis.

Integration with CIS and Billing Systems

MDMS automates and streamlines the identification of accounts with potential theft, thus reducing the time and expense of unnecessary site visits by revenue investigators. With visibility into the probable condition of each meter in the system, revenue investigators can monitor accounts systemwide without additional investments in time, resources, meter seals, locks, and other security gadgets.

For optimum performance of AMI-supported applications such as tamper or leak detection and processing of on-demand and off-cycle reads, MDMS should be integrated with utility functions carried out in CIS, billing, and other systems such as load control. Customer service personnel, for example, should have access to daily and interval read information provided by AMI to respond to billing inquiries, process service cancellations, and perform other functions. This will require development of new screens for integrating and displaying data and can be time-consuming to develop and test.

Interestingly, MDMS identifies meter failure before the billing cycle, thus avoiding billing errors on both the hardware and software components of AMI, both contributors to non-technical losses.

Integration into AMI and Enterprise

To realize the benefits of revenue protection, including meter tempering and illegitimate consumption, AMI must be capable of providing the data required to detect theft. This means that MDMS should be able to ingest and analyze the AMI data to initiate, track, and close-out follow-up work orders via the utility's work order management system with respect to meter installations, change-outs, communications interfaces, maintenance, and upgrades.

MDMS is an integral and essential part of AMI with respect to developing solutions for non-technical losses.

MDMS and the AMI Technology Evaluations

Conceptually, the meter module hardware, communications infrastructure, AMI head-end system, the MDMS, and the integrations with a utility's existing back-office systems should be thought of as one end-to-end integrated and seamless solution that, only together, can enable the utility to achieve the expected benefits of AMI. Hence, it is beneficial for a utility to assess the capabilities it requires of an MDMS and determine how the AMI data will touch the utility's existing systems, the same time when evaluating AMI technologies and developing an AMI business case.

Meter Data Management System, Tram, Hahn and Ash, Chris, Enspiria Solutions. August 29, 2005.

Statistical Analysis

AMI generates a wealth of data. The shear volume of this data demands that software applications be developed to perform statistical analysis for it to be useful for detecting and correcting non-technical losses. As meters become more sophisticated (solid-state meters flag many meter-tampering techniques automatically in real time), so do thieves. Software applications can be used to strike the balance in favor of revenue assurance.

Some of the more prevalent software applications and techniques for statistical analysis are described in the sections below.

Customer Profiling

Load profiles and data mining techniques can be used to minimize non-technical loss activities. Load-profiling methods and data-mining techniques can be used to classify, detect, and predict non-technical losses in the distribution sector due to faulty metering and billing errors. They provide a framework for the analysis of customer behavior.

Load Profiling

The key to this approach is the recognition of significant deviations known as outliers in the customer behavior patterns. The method of doing so involves modules including the load profiling and non-technical losses analysis in processing large volumes of data relating to customers' electricity consumption patterns. The load profiling module includes clustering customer behavior according to the loading conditions identified and allocating the clustered load profiles to the respective categories based on the customer and commercial indices. The non-technical loss analysis module uses the representative load profiles as a time series model and detects the outliers based on the set up benchmark based on abnormal and normal behavior patterns. The detected abnormalities due to non-technical loss activities are used as a reference to develop a forecast model on non-technical loss profiles with other external features.

Framework Analysis of Customer Behaviour due to Non-Technical Losses in Malaysian Electricity Supply Industry, Anisah Hanim Nizar, ITEE. July 17, 2006.

Interval Metering

Since AMI systems can support frequent readings and high data resolution, interval metering is possible. This allows the utility to study consumption patterns for anomalies that may indicate metering problems.[76]

Some "smart meters" measure consumption in intervals of an hour or less. The resulting increase in data points (from 4 or 12 per year to 8700+) allows utilities to develop highly sophisticated customer profiles. This information can be used to analyze consumption patterns at sites where theft is suspected.

Utilities can develop and compare profiles within the billing system. However, the process would likely slow down bill production. A far more efficient solution lies in the use of an out-of-the-box business intelligence application that extracts data from a billing or meter data management application, then builds and compares profiles in a non-production environment.[77]

A list of significant deviations based on interval data provides targets for investigation. Deviation from a profile norm is a good indicator of theft, sufficient to merit investigation.

Distribution Analysis

Metering cannot detect bypass-tapping supply before it reaches the meter. For most utilities, bypass is the primary theft method. Bypass on underground lines can go undetected for years.[78]

Using data from smart meters, distribution management systems can be used to reach a solution to this problem. A distribution management system can correlate energy meter readings with available feeder load data to identify feeder loss characteristics and a profile. Utilities can use these to create a ranking of the worst performing distribution feeders. This system perspective of feeder loss allows a utility to address load theft where it is greatest. Also, smart-meter-provided power quality data (for example, voltage, current, and power factor) can assist in determining the feeder section losses.

This analysis helps narrow the source of a loss to a relatively small number of sites. Looking at the accounts associated with those sites, along with information on ownership and purported use, points to the likely location of the theft.

Trends and Comparisons

Custom algorithms and a formal process are required to identify trends. Energy consumption needs to be compared by individual customers and by class of customers. Comparisons are made by combining AMI data with the following:

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[76] Load profile analysis using monthly meter readings is impractical for detecting energy theft. *Algorithm for Detecting Energy Diversion,* EPRI. 1991.

[77] New metering & grid applications improve theft detection, Adrian Patrick, PhD, Automatic Meter Reading Systems, Oracle, Utilities Global Business Unit. July 31, 2007.

[78] When the power is used for illegal, high-consumption "growing" and drug-manufacturing purposes, losses can be substantial.

- class of customer
- geographical information
- other utilities—cable, gas, water
- customer history and behavior patterns

Statistical Algorithms

MDMS uses a series of statistical algorithms that, in essence, perform the same initial screening and analysis work usually performed by a team of utility revenue assurance experts, only in a more consistent manner and at a much lower cost.

MDMS identifies revenue leakage by applying these algorithms, along with revenue assurance investigation best practices, across multiple utility internal data sources (CIS, MIS, WFMS) and appended with external data sources (SIC, zip +4, credit score, weather) to create a list of suspect accounts. The suspect list is a prioritized list of premises or accounts with reason codes and a weighted revenue recovery valuation of each opportunity. A suspect list is provided to the utility's revenue protection investigation team on a periodic basis for field investigation and subsequent actions (for example, customer contact, back-billing, mediation, and negotiations).

Geographical Information Systems (GIS)

GIS mapping and integration with customer databases is used to identify and locate consumers on the geographical maps being fed from the distribution network. There may be cases where an electric connection exists, but is not in the utility's record. There may be instances of unauthorized connections or unrecorded connections. On the other hand, there may be instances where a connection is recorded, but does not exist physically at the site.

GIS provides utilities with accurate data and useful information to manage their assets and customer base. GIS coupled with GPS can assist in maintaining data integrity and recovering "lost revenue."

GIS should be used to provide aerial photographs or maps of the area, with spatial references to the physical and electrical distribution network, metering points within buildings, and buildings without meters installed. All network and customer documentation should be linked, and all assets in the area should be mapped. Widespread access to relevant data should be available through a web-enabled client-server.

Installation of AMI at the substation level helps to target areas where technical and, more importantly, non-technical losses are problematic.

Results from analysis using GIS-enabled tools can be used to focus energy audits by revenue protection teams. In the case of major retail and industrial customers, technical specialists can prioritize locations for on-site audits, checking meters and installations, instrument transformers, metering and billing constants and ensuring that no by-passing is taking place.

GIS is an ideal integration platform for meter data, supervisory control and data acquisition (SCADA), and customer information systems, as shown in Figure 3-2.

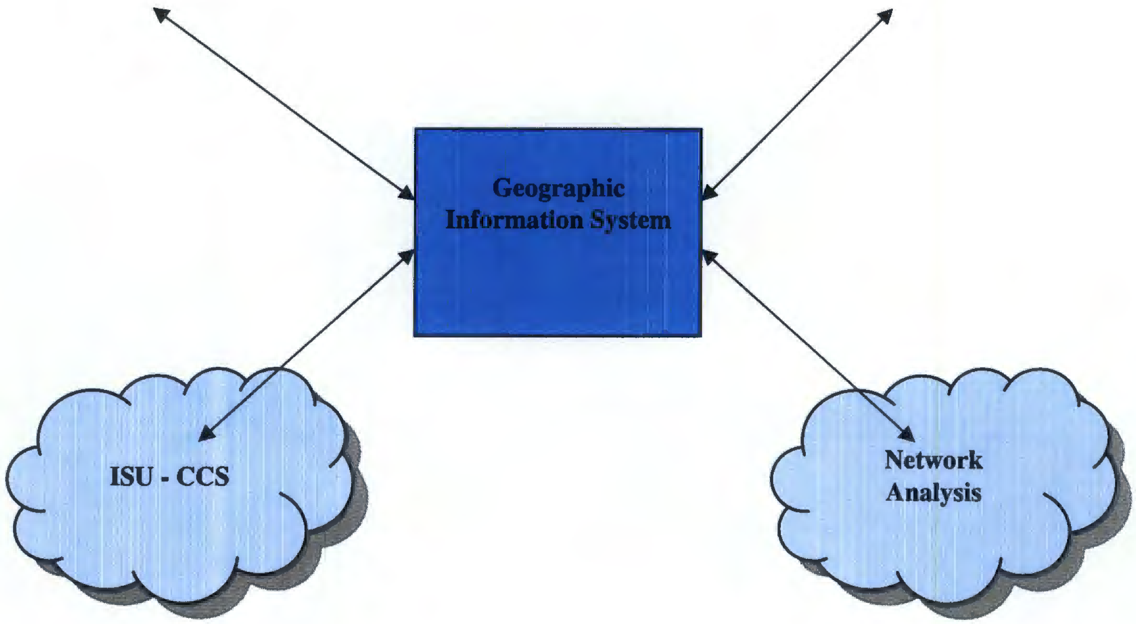

Figure 3-2
Geographic Information System

Tasks for which spatial data can improve processes are meter reading (including rollout of AMI systems), credit and collections, customer analytics, billing, and customer communications. An enterprise GIS fully integrated within the mainstream of utility IT infrastructures helps utilities understand customer behavior and their transactions.[79]

GIS can help visualize significant mismatches between known usage and actual consumption using GIS advanced network modeling.

Many utilities consider the GIS system as the "ultimate" source database, acting as a common repository for all enterprise applications. This is accomplished by integrating GIS technology into the mainstream business operations of the company.

[79] *GIS Enhances Electric Utility Customer Care*, An ESRI ® White Paper. May 2007.

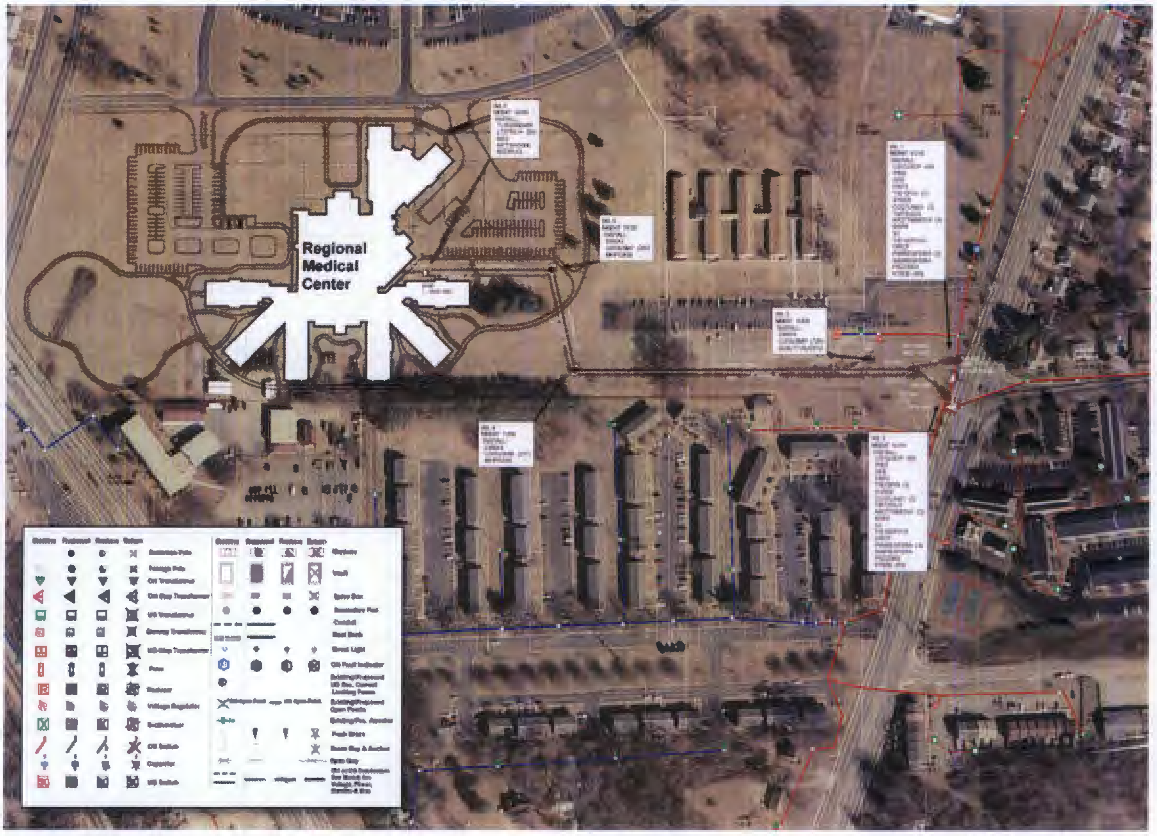

Figure 3-3
GIS Aerial Map

GIS Integration Functional Requirements

The functional requirements for integrating AMI with GIS are as follows: [80]

- Complete automation of the distribution network is not possible. It would require implementation of SCADA/DMS at every section of distribution system, which is prohibitively expensive. Hence, getting real-time data from SCADA/DMS for all parts of distribution network is not possible. This problem can be overcome by the integration of GIS with AMR/AMI.
- Normally, the metering data from AMR/AMI are available to billing personal. However, these data are not available to other employees directly. Once integrated with GIS, every employee can have access to data through multiple GIS applications.
- AMR/AMI data are helpful for detecting losses in the distribution system. Using GIS, losses can be viewed geographically and analyzed. This analysis can be used to map areas where there is a high incidence of theft or other distribution system losses. These maps can be used to develop predictive models (Figure 3-3).
- Energy consumption information can be used to build databases of real-time and historical (periodical) demand and energy data at the source (for example, feeders and

[80] A detailed discussion of this subject can be found in *GIS integration with SCADA, DMS & AMR in Electrical Utility*, Uday D. Kale and Rajesh Lad. Reliance Energy Ltd., Map India. 2006.

DTs) and load (consumers) levels. This information can be used to build network simulations of loading conditions and for load forecasting. These databases can be helpful in developing profiles, behavior models and incidence indicators for theft.

- With the data received from AMR/AMI, GIS tools can be used for energy auditing in a geographic context, which is useful in specifically identifying particular areas suffering high energy losses.
- The correct assessment of technical and non-technical loss components needs correct metering data. This information can be provided over the GIS platform. GIS tools can be used by network analysts to identify and display spatially feeders, transformers, and distribution areas having high-energy losses (Figure 3-4).

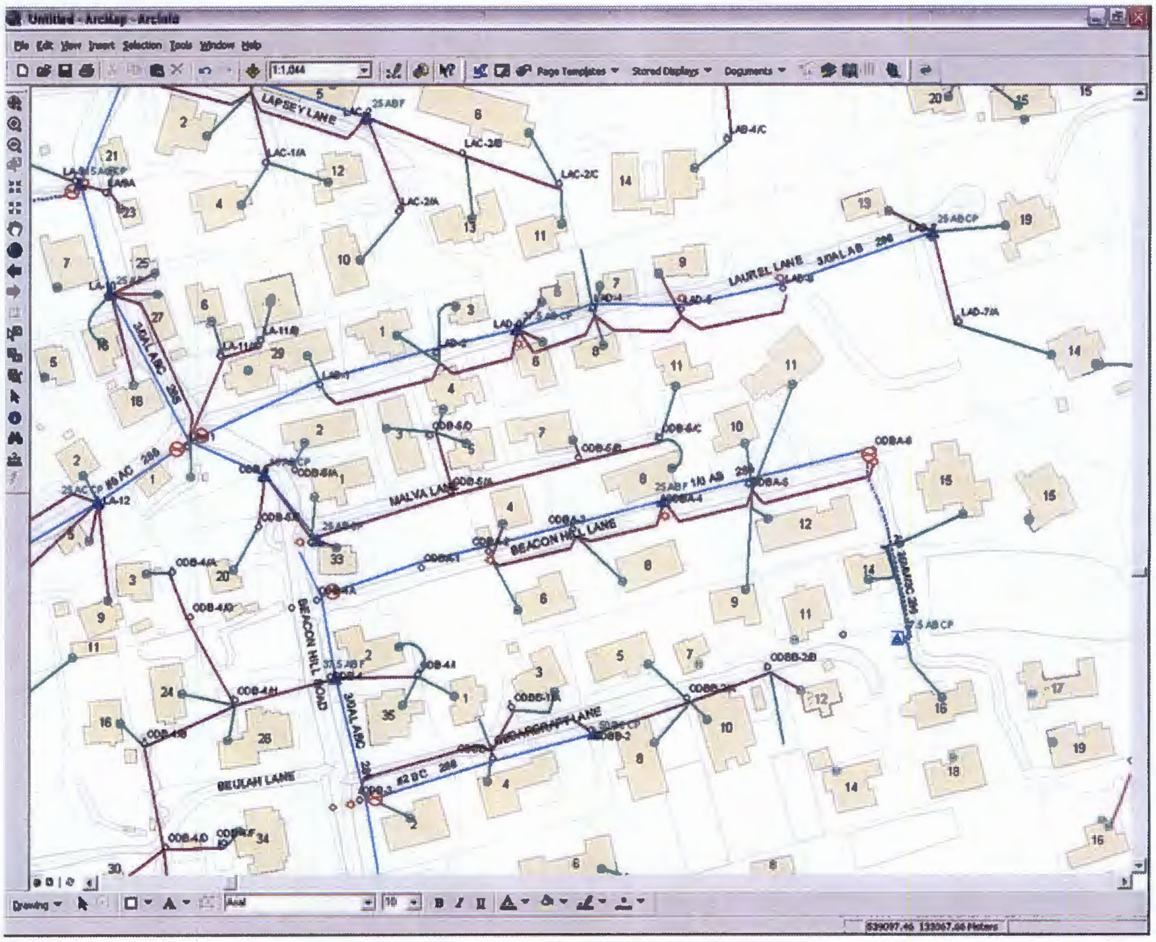

Figure 3-4
GIS High-Energy Loss Map

GIS and Field Inspections

GIS mapping of AMR/AMI data has been used successfully to identify locations for field inspections. These have led to high "hit rates" for the detection of meter tampering. An example of GIS for field inspections is shown in Figure 3-5.[81]

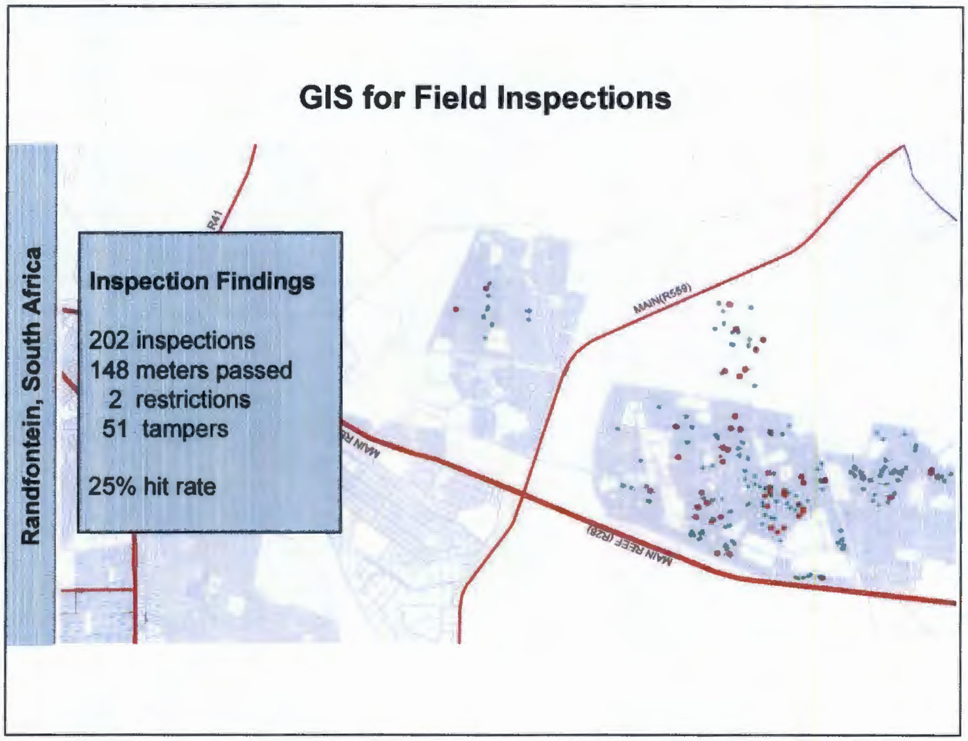

Figure 3-5
GIS for Field Inspections

Analyzing Theft at Substation Level

With integrated GIS, it is possible to access exactly the geographical areas where theft is most prevalent, areas where theft can be preempted by enhanced levels of vigilance, and areas where revenue assurance should step up its efforts and be more accountable for results. Typically, the area served by a substation is only a few square kilometers in size, facilitating the implementation of corrective measures.

GIS can play a major role in identifying areas of the distribution network where theft is likely. Identifying potential theft in the distribution network is accomplished by the integration of billing and SCADA systems on a GIS platform.[82]

[81] *Resource & Revenue Protection as a Tool for DSM*, Christophe Viarnaud, Actaris and Gregor Schmitz, BreakThru Consulting.

[82] *Role of GIS in Preventing Power Pilferage,* Dr. Nagesh Rajopadhyay, Manish Arora and P. Madhusudhan, Info Tech Enterprise Limited, Hyderabad. GIS Based Distribution System Planning, Analysis and Asset Management Training Program, USAID.

SCADA systems continuously collect real-time readings of all electrical parameters at monitored points on feeders.[83] The system obtains information on the status of various switching devices (for example, circuit breakers, switches and isolators) and transformer parameters (for example, tap position).

When electronic meters are installed at the customer level, they can be equipped with an interface for communications with the SCADA system, using an industry standard protocol. Meter readings can then be used both to monitor the load and to detect attempts to tamper with the meter. As soon as a tamper is detected, the meter/consumer can be tagged on the GIS system. The information can then be passed on to revenue assurance for physical checks and corrective action.

PSS/Engines™ must be interfaced with GIS for network analysis and optimization. A data model must be created in GIS for geographic locations as well as for the network.

Steps for the system and database integration and GIS mapping:

- Interface of billing system to GIS (GIS application software reads external relational database management system [RDBMS] of billing system).
- Entry of billing-related information to customer database.
- Identify the total power delivered from the substation (P-total) and the total power billed to the customer (P-billed).
- Calculate network power loss (P-lost) with network analysis tools and map network data in GIS.
- Calculate power theft (P-theft) or commercial loss at the substation level. Formula: (P-theft) = (P-total) - (P-billed) - (P-lost).
- Plot the results on GIS.

A similar analysis can be made at the transformer level, provided that the meter is installed at the transformer and a reading is available.

A link must be maintained between the external billing database and the GIS database. Billing data must be populated simultaneously in the external database and the GIS database. After the entry of meter data at a substation level, the system can be asked to evaluate the total commercial loss.

[83] These parameters include voltage, angle, power factor, active power, reactive power, and energy.

Implementation of AMI Technology

The way in which an AMI installation is planned and executed has a major impact on its success in ensuring that the technologies are installed properly, detecting meter tampering and by-pass at the time of installation and setting up and integrating the data management systems and GIS platform for revenue assurance programs in the future. It must be recognized that installation of hardware and software is as important as the technologies themselves for realizing the benefits that AMI offers for the detection and control of non-technical losses.

Successful implementation of AMI technology requires the participation of experienced revenue assurance staff at all stages of the process—planning, procurement, installation, and integration into the utility enterprise systems. These individuals have valuable insights into the transition from manual to remote meter reading and auditing. They have much on-site experience to share for meter replacement. Moreover, they understand the need for comprehensive data management tools. Most importantly, revenue assurance offers quality control for the realization of the operational savings that provide the economic justification for many AMI programs.

4
CHAPTER 4

Overview PPL Electric Utilities

PPL Electric Utilities is the regulated electricity and gas subsidiary of PPL Corporation. The annual revenues and assets of PPL Corporation are $6.9 billion and $19.7 billion, respectively. PPL Electric Utilities serves over 1.4 million customers over 10,000 square miles in Central Eastern Pennsylvania (Figure 4-1).

PPL Electric Utilities has a peak load of ~7,700 MW with 36.7 billion kWh delivery.

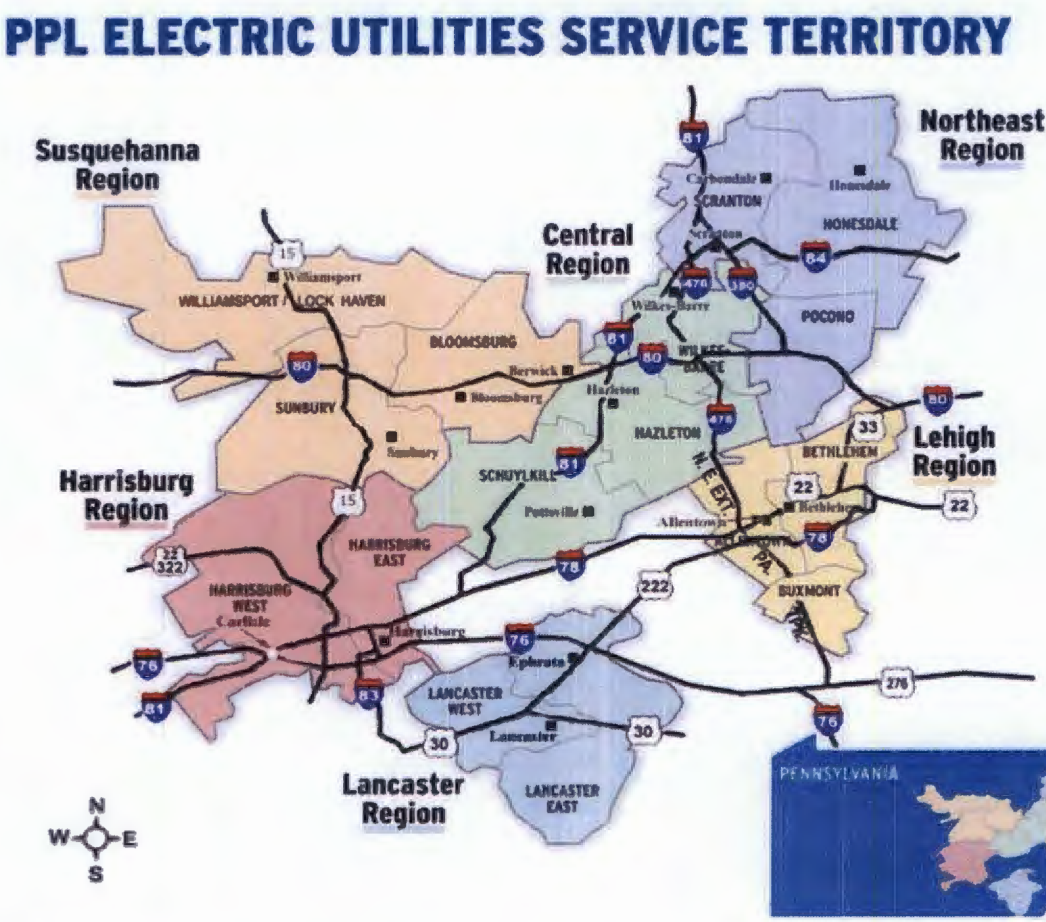

Figure 4-1
PPL Electric Utilities Service Territory

PPL Electric Utilities was one of the first utilities to introduce an automated meter-reading system, starting the program in November 1999 and completing the deployment to its 1.4 million customers in October 2004. Beginning in the spring of 2002 and concluding in the fall of 2004, PPL deployed an automated meter-reading system that included the replacement of over 1.4 million meters, installation of communications equipment in over 330 substations, and modified meter data and billing systems. Total implementation cost was $163 million. The automated meter-reading system replaced 175 manual meter readers and allowed the reduction of personnel for large power installations from 17 to 11.

With manual reads, PPL Electric Utilities experienced 95% accuracy (due to human error and weather, especially snow); accuracy with automated meter reading is now close to 99.8%.

PPL Electric Utilities started change management for business processes six months before installation. Before installation started, 200 business processes were reviewed; 70 risks were identified and addressed and appropriate changes made to ensure the successful transition to the automated meter-reading system. Many of these changes related to billing processes and impacted revenue assurance and, thus, non-technical losses.

The information technology staff was actively involved in the project team, contributing to the smooth transition. During the installation period, manual meter reads were sent to billing using middleware, so downstream processes did not notice the difference between manual and remote meter reads. The computer software programs and interfaces necessary to transfer the automated meter reads to the PPL billing system were developed in-house. Among these were the data validation and revenue assurance tools. Statistical analysis was used very early on. From the beginning of the project, the information technology staff, using its own software, provided effective and productive applications for revenue assurance.

Although the system deployed by PPL Electric Utilities was an automated meter-reading (AMR) system, it was designed as an advanced metering infrastructure (AMI) system upon which expanded capabilities could be deployed. These expanded capabilities include two-way communications and the use of a commercial MDM solution.

The AMI system reads meters three times per day; hourly data collected daily for each customer. The database currently (2008) holds over three terabytes (two years of data). This is the largest database of hourly data in the industry.

PPL Electric Utilities was one of the earliest utilities to deploy and utilize AMR/AMI throughout its entire service territory, establishing it as one of the leaders in the industry. As of 2006 it had the second largest deployment in the United States (1,353,024 meters), after PECO Energy (1,759,913); Wisconsin Energy was third (723,000), Wisconsin Public Service fourth (396,837), and United Illuminating fifth (324,992).

The transition from manual to remote meter reading at PPL Electric Utilities was well managed with an inclusive and highly competent project team, making it a model for the industry. Most importantly, with respect to the subject of this study, the AMR/AMI system at PPL Electric utilities provides new and innovative tools for revenue assurance that have a positive impact on the reduction on non-technical losses.

Revenue Assurance Using Meter Data from AMI with Meter Data Management Software

AMI fundamentally alters the way revenue assurance operations are performed. In the past, the Revenue Assurance group at PPL Electric Utilities used various strategies to identify specific target accounts for investigation. Most of these strategies involved manual analysis of large quantities of data, a labor-intensive exercise. The data available for such queries were generally limited to daily and monthly consumption. The results were based on an *ad hoc* process that takes considerable time, with different screening tests being designed and deployed at different times. AMI, with a robust MDM system, changes this paradigm in several ways.

The collection of higher-frequency data and meter status by AMI—reverse rotation flags, outage count indicators, interval data, and metered usage on previously cut meters—is just the beginning of the assurance solution. MDM software helps utilities analyze AMI data, providing knowledge about customer energy use. In-depth analysis helps pinpoint where and by whom power is being diverted, making it easier to identify cases of theft. For example, such analysis enables the utility to discover when there is energy use on non-paying accounts and when there is no use for specific time periods on an active account.

Data Repository

The core repository of data is collected from multiple sources: AMI meters, weather, customer and billing, SCADA, GIS mapping and real-time pricing, as shown in Figure 4-2. The data are validated and stored in two scenarios, working and approved.

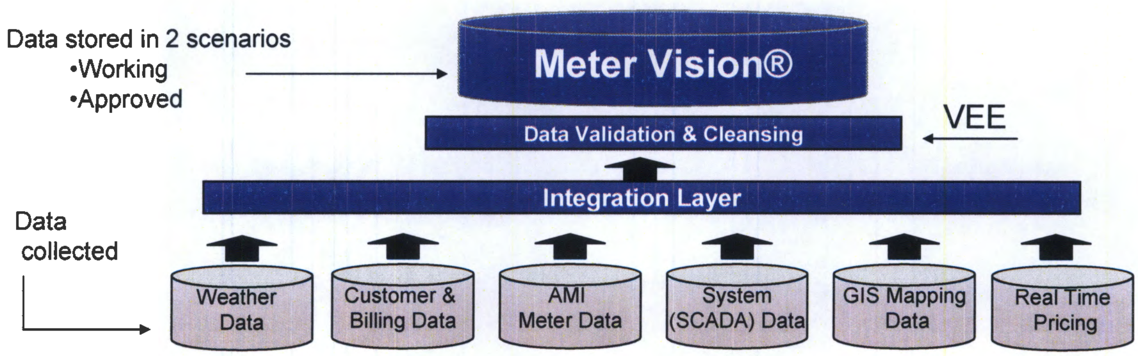

Figure 4-2
Data Repository

Data Repository and Applications

Revenue assurance software allows PPL Electric Utilities to zero in on problem accounts by combining data collected by the AMI system, such as daily readings, interval data, and momentary interruption notifications (blink counts) with other pertinent information such as daily temperatures, meter status, and account status.

Chapter 4

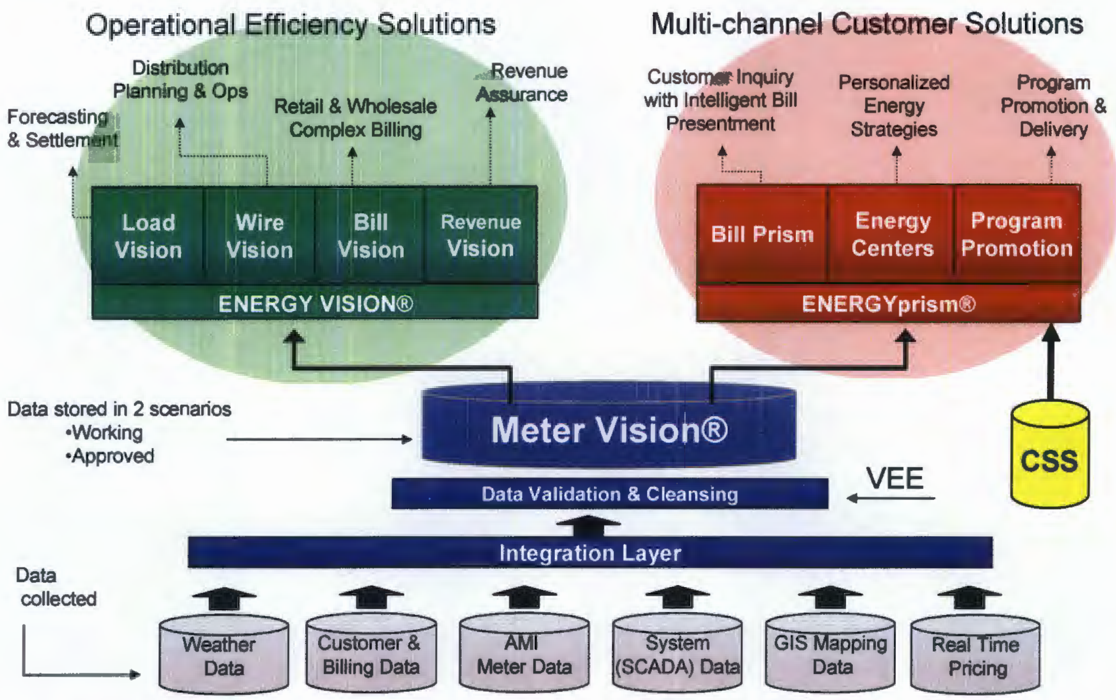

Figure 4-3
Data Repository and Applications

The combination of data and applications for analysis together constitute the Revenue Vision solution at PPL Electric Utilities (Figure 4-3).

Revenue Vision

The Revenue Assurance group at PPL Electric Utilities uses MDM software, called Revenue Vision, to help them simplify the process for identifying possible cases of theft, meter tampering, or equipment problems. This takes a significant amount of guesswork out of the effort to identify possible theft cases. Rather than make assumptions about the cause of a reduction in consumption, the granularity of data available from MDM can provide a pattern that can be used to identify theft or failing equipment with a high degree of confidence so that the site visit to confirm will be fruitful. It also allows users to create rules and logic, manage the list of outputs, tweak logic for better results, and group the results by geographic location to make it easier to assign work to field investigators. An optimum solution would automatically notify group members of anomalies around usage patterns.

PPL Electric Utilities uses a commercial MDM solution to improve analyses of large volumes of interval, daily, and meter data collected by its AMI system. By combining various meter, premise, and account data, the software makes it easier to identify problem meters. PPL Electric Utilities identifies suspicious consumption patterns by applying specific, utility-defined screening tests to a targeted population of accounts, meters, or other entities. The goal is to define tests narrowly enough so that the data combination yields a true and manageably sized "hot list" of accounts requiring investigation.

Revenue Assurance Application

- The revenue assurance application is used today to find meter issues as well as theft.
- The application collects raw data from meters with a specific scenario.
- For example, meters with 3 hours of no use are collected between the hours of 6 pm and 6 am and reports them to a "hot list" for further investigation.
- Additionally, it collects meters that have reverse rotation with blinks and puts them on a "hot list" for additional investigation.

Tests

The Revenue Assurance group began its project by evaluating existing tests already in use for assessing monthly meter readings. During the course of the review, they were able to determine the biggest revenue loss issues, such as equipment malfunctions, installation issues, and potential theft, and to identify usage patterns that were indicative of each problem, as well as the customer class or attribute that should be tested. Upon completion of this exercise, the group came up with eight logic tests to implement within the MDM application and then determined the criteria for each; for example, the meter type or the account type as well as selecting a schedule for running the test (weekly, monthly, or quarterly).

Design and implementation of screening tests within MDM are distinctly separate steps. Analyses are designed to fit customer load and data characteristics to effectively identify energy theft or tampering. Once an analysis is designed, it is implemented as a regular production process, making it possible to keep up with the examination of current data and alert the Revenue Assurance group of anomalies as soon as they arise.

The design step involves exploratory analysis of different test schemes by running, reviewing, and comparing different result sets. Hourly data are utilized for these tests and supplemented by external data sources such as weather data, GIS, and customer characteristic data. In the design phase, these tests are run on all or just a sample of customers, with the primary purpose of evaluating the effectiveness of the tests, rather than simply generating customer lists from the tests.

Tests

- Periodic zero use/with blink—shows meter blinks and zero usage
- Periodic zero use/no blink—same above with no blinks
- Reverse rotation/with blink—shows reverse meter rotation
- Reverse rotation/no blink—same as above with no blink

Note: Typically, abnormal blink counts and reverse rotations counts are due to meter tampering.

PPL continues to refine other tests that will allow them to monitor accounts within two days of an event (for example, termination for non-payment or slowing or stopped meter).

The implementation step is automated. Once logic tests are found to be effective by the analyst, they are put into production by scheduling them as automated runs for whatever period makes sense. All AMI data are initially screened by the validation rules inherent in the MDM system.

After validation, certain accounts are identified for further review. The revenue assurance analyses are run automatically on selected meters. Tests can be nested into a single logic string within a single production run, rather than performed sequentially in multiple runs.

Analysts apply standard tests or test combinations to specific accounts or groups of accounts. Failure of a combination of tests may detect meter tampering. For example, the combination of a loss of power indicator on a meter with a reverse rotation flag is a better indicator of theft than either test alone. No one test determines energy theft or meter tampering, but various combinations of failures may place an account or meter on the suspicious account list.

Workflows

The next step in implementing the logic tests required that a workflow be set up for each of the tests (Table 4-1). The workflows consist of a name, brief description, the group of entities to be included in the test, and the filters necessary to identify the attributes of the entities included. Once the workflows were completed, the group determined how often to run the test.

PPL Electric Utilities generally runs tests weekly, but has the flexibility to change the frequency of test runs. Weekly runs allow better management of output, and there is an added security benefit from a frequent "electronic eye" on every meter in the field.

Table 4-1
Revenue assurance workflows at PPL Electric Utilities

Revenue Assurance Workflows at PPL Electric Utilities	
Workflow	**Description**
800 Series Commercial	Captures commercial meters that have 20% or greater decrease in monthly consumption and/or peak demand in comparison with lowest monthly consumption and peak demand of previous 12 months
800 Series Residential	Captures residential meters that have 20% or greater decrease in monthly consumption in comparison with lowest monthly consumption of previous 12 months
Seasonal Use	Captures seasonal meters that have 20% or greater decrease in seasonal consumption and/or peak demand in comparison with seasonal consumption and peak demand 1 year and 2 years ago
Billing Constant	Captures meters for which billing constant changed from that of previous month
CIM Monthly Commercial	Captures commercial meters that have registered 1000 kWh of consumption since account became inactive
CIM Monthly Residential	Captures residential meters that have registered 1000 kWh of consumption since account became inactive
CIM Weekly Commercial	Captures commercial meters that register average daily consumption of 500 kWh or greater since account became inactive
Load Factor Commercial	Captures commercial meters that have monthly load factor of 1 or greater
Load Factor Residential	Captures residential meters that have monthly load factor of 1 or greater
Periodic Zero Use Commercial	Captures commercial meters that register four or more consecutive hours of true zero use during calendar month (excl. power outages)
Periodic Zero Use Residential	Captures residential meters that register more than 40 occurrences of consecutive 12 hours of zero use during calendar month (excl. power outages)
Reverse Rotation and Blink	Captures meters that register reverse rotation and blinks, indicating meters potentially tampered with
Reverse Rotation and No Blink	Captures meters that register reverse rotation but no blinks, indicating defective meters creeping backwards
Reverse Spike Commercial	Captures commercial meters that have more than 6 occurrences of 90% or greater decrease in daily consumption from previous day during calendar month
Reverse Spike Residential	Captures residential meters that have more than 6 occurrences of 90% or greater decrease in daily consumption from previous day during calendar month
Zero Use Commercial	Captures commercial meters that register zero consumption for calendar month
Zero Use Residential	Captures residential meters that register zero consumption for calendar month
Company Use	Captures meters classified as Company Use so they can be verified as such
Commercial Rate and Residential Revenue Class	Captures meters that have commercial rate class and residential revenue class
Residential Rate and Commercial Revenue Class	Captures meters that have residential rate class and commercial revenue class

Figure 4-4 shows a workflow that is used to find commercial meters that have 20% or greater decrease in the monthly consumption and or peak demand in comparison with the lowest monthly consumption and peak demand of the previous twelve months.

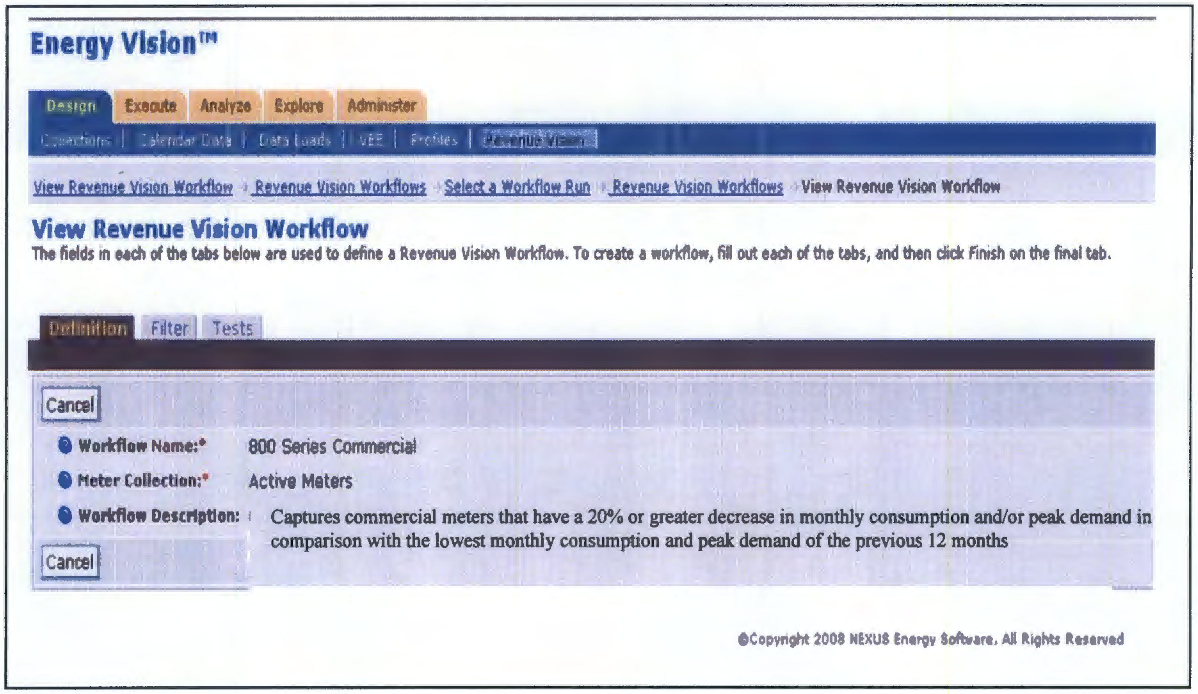

Figure 4-4
800 Series Commercial Workflow (Screen Print)

Filter

Within Revenue Vision (see Figure 4-5 Data Repository and Applications) a filter is applied by selecting the specific attributes, as well as a specific value such as commercial vs. residential—active vs. inactive—and so on.

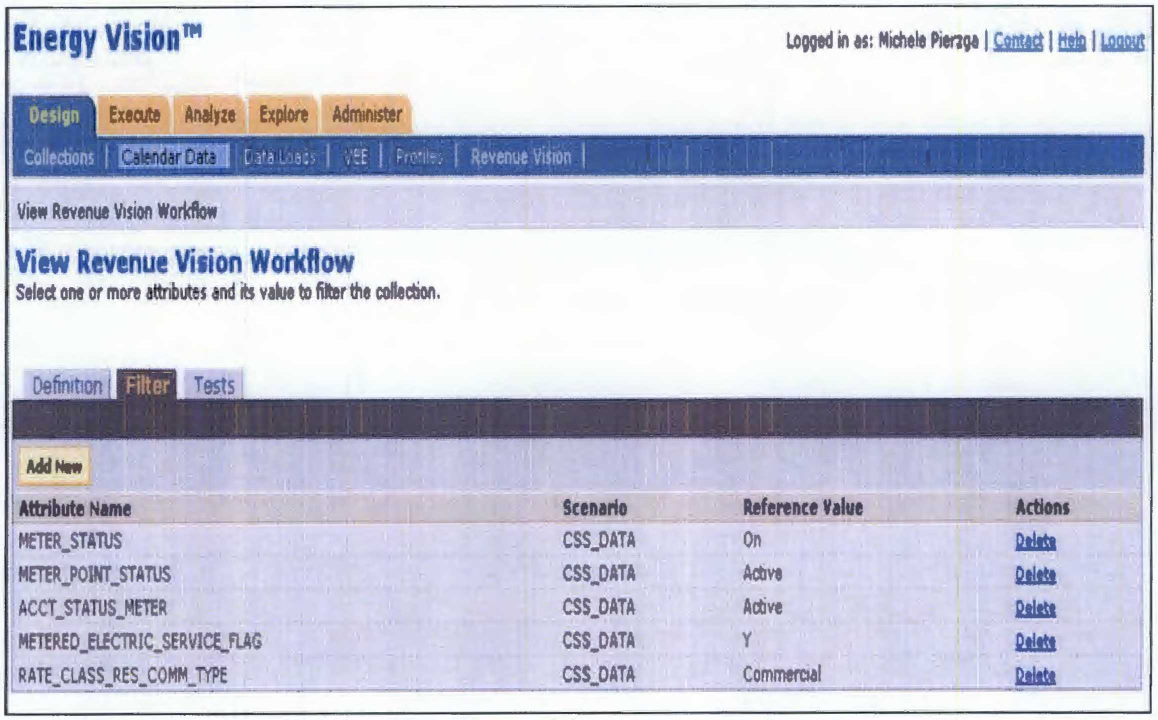

Figure 4-5
Filter (Screen Print)

"Hot List"

The results are displayed on a "hot list" (Figure 4-6) from which a Revenue Assurance specialist can pinpoint candidates for further investigation and corroboration of the AMI indicators.

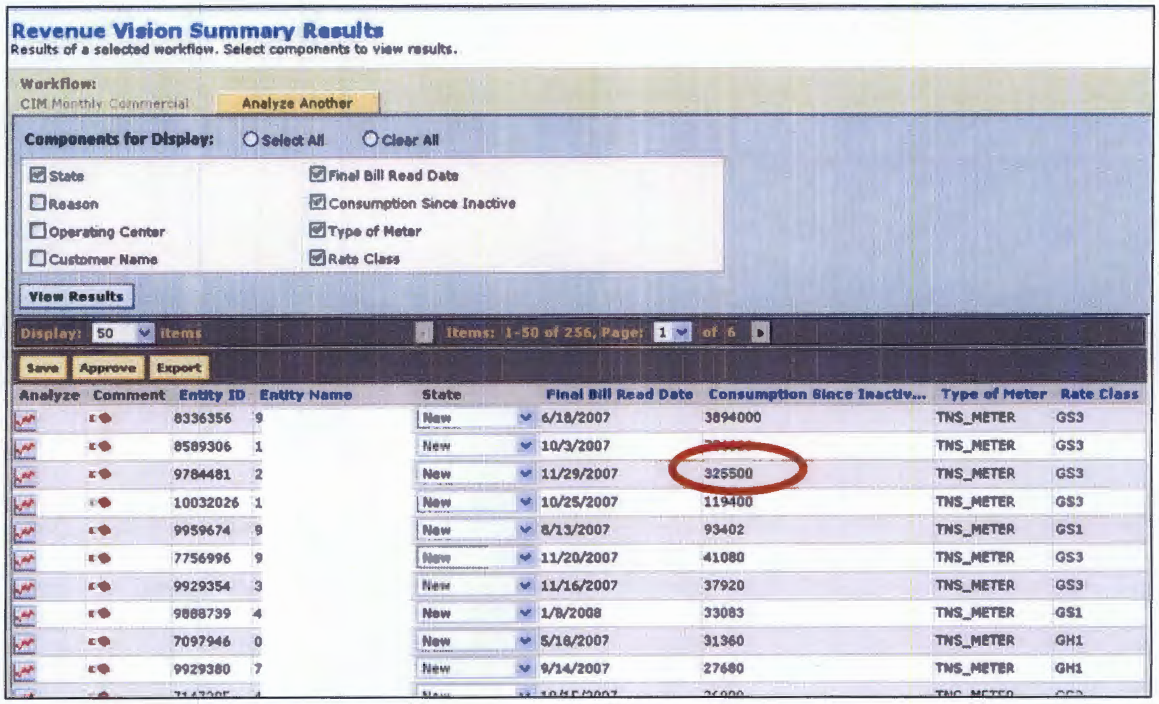

Figure 4-6
Hot list (Screen Print)

The "hot list" is used to prioritize revenue assurance leads for field personnel, thus reducing service order costs and efficiently identifying likely sources of non-technical losses.

Example of Theft Detection Using a Usage Pattern

In one recent case, PPL Electric Utilities was able to identify potential theft by looking at a usage pattern (Figure 4-7).

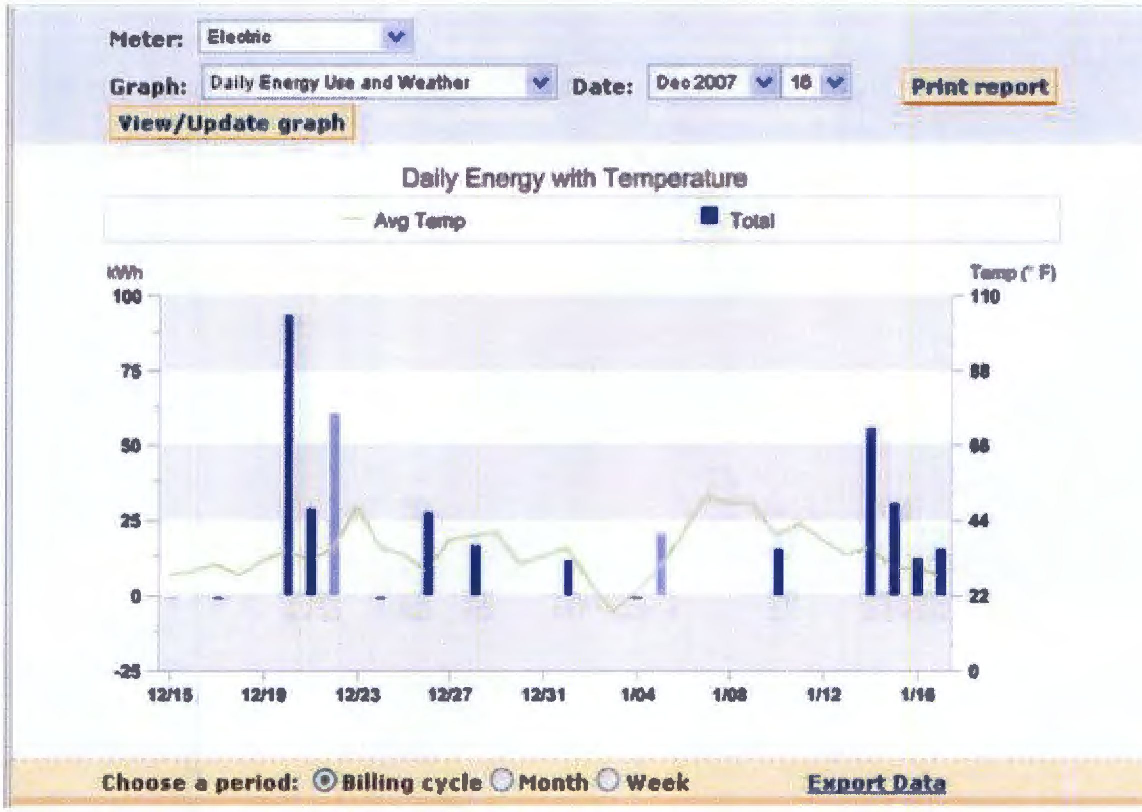

Figure 4-7
Usage pattern indicating abnormal meter behavior

The graph, taken from reports output from the MDM, indicates a suspicious usage pattern, with the meter going into a reverse rotation several times during a single billing cycle. What is more, there are days during the month when the customer is not using any power, while on other days the meter recorded usage. On December 20, 94 kW of usage was recorded, for example, while on January 3, when the temperature was -8°C, no usage was recorded. An investigation of the premises based on analysis of the AMI data indicated that the customer had tampered with the meter. Wires were attached to the meter's potential clip (Figure 4-8).

Figure 4-8
Meter recorded in Figure 7 with wires attached to its potential clip

The bypass was controlled by a simple toggle switch (Figure 4-9).

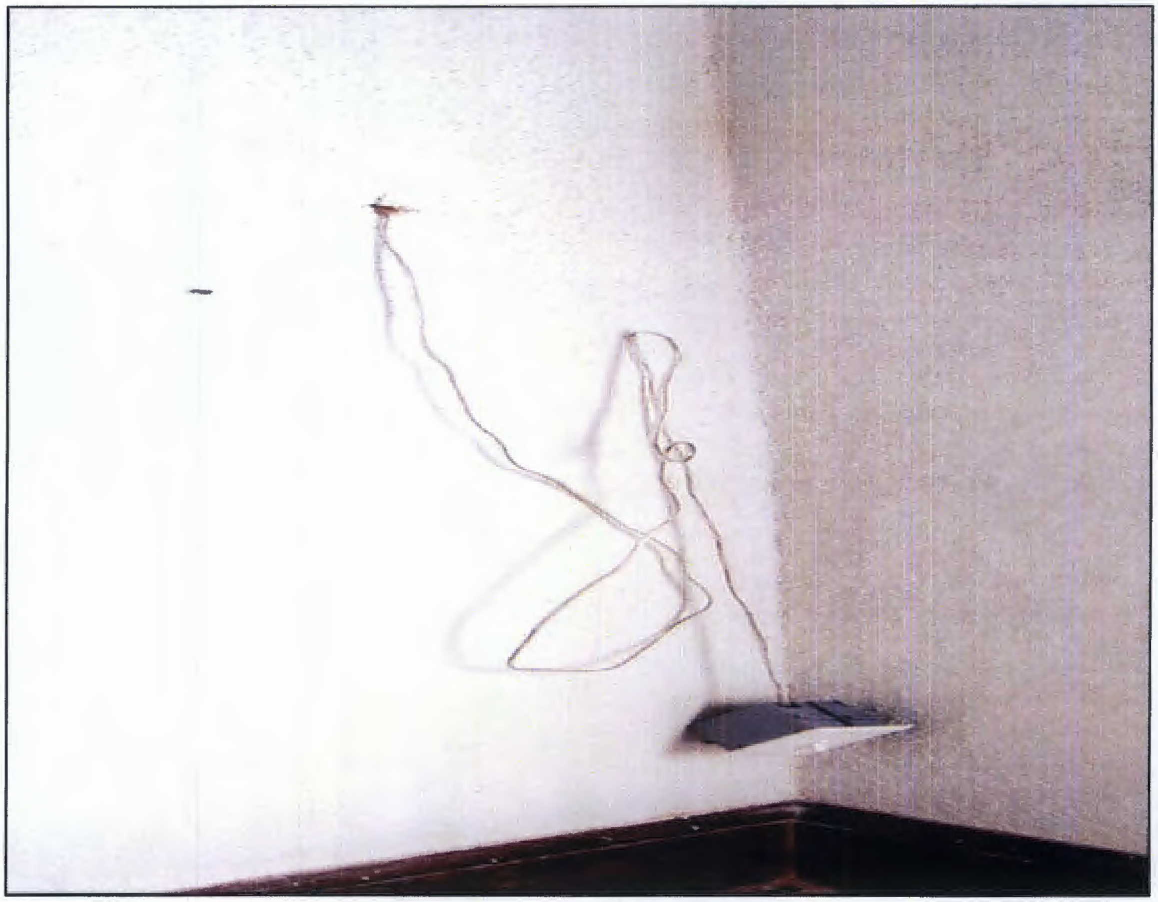

Figure 4-9
Toggle switch controlling the meter bypass

In this case, PPL Electric Utilities was able to use the interval data to extrapolate usage for rebilling purposes from the periods that were recorded.

Further, PPL Electric Utilities can use the detailed data for responding to questions raised by the judicial system.

Results

PPL Electric Utilities has had positive results from implementation of MDM-based revenue assurance software. The results for April and May 2008 are shown in the insert below.

RESULTS
April and May 2008

- Forty (40) cases were identified for a field investigation where 100% resulted in action being taken.
- Eighteen (18) of the cases were a result of equipment issues.
- In twenty (20) of the cases, theft was detected.
- Two of the cases revealed customer-owned generation via windmill and solar panel; these cases were identified through anomalies in blink counts and reverse rotation on the meters.

Reduction of Non-Technical Losses Using Meter Data Management

As defined in Chapter One, non-technical loss comprises distribution system losses caused by factors at the point of delivery and measurement. These losses are associated with unidentified and uncollected revenue, arising from pilferage, tampering with meters, defective meters, and errors in meter reading and in estimating un-metered supply of energy. System miscalculation on the part of utilities, due to accounting errors, poor record keeping, or other information errors also contribute to non-technical losses. In this example, the focus has been primarily on issues related to theft. However, in the future, PPL Electric Utilities expects to further maximize the benefits that can be derived from its meter data, such as using the features of its MDM system in customer service to respond more quickly and accurately to high-bill inquiries.

AMI at PPL Electric Utilities is an evolving enterprise. The ongoing initiatives of the AMI operations team will lead to further reductions in non-technical losses, as well as further benefits in terms of operational efficiencies and customer service.

Sources

AMI and MDM Program—PPL Electric Utilities, Mike Godorov, Manager; AMI Operations, Kimberly Golden, Supervisor—Information Solutions; and Wayne Fairchild, Special Project Manager, AMI, interviews and presentation. September 18, 2008.

PPL Electric Utilities Reduces Revenue Losses with AMI, Bernie Molchany, Manager—Revenue Assurance, PPL Electric Utilities; Michele Pierzga, Lead Business Systems Analyst, PPL Services Corporation; and Jackie Lemmerhirt, Director of Product Management, MDM, Aclara, Metering International. Issue 3 2008.

Using Meter Data from AMI with Meter Data Management Software to Identify Theft and Equipment Issues, Michele A. Pierzga, Lead Business Systems Analyst, PPL Services Corporation, Autovation 2008, Atlanta, GA. September 7, 2008.

A
APPENDIX

Product Differentiators

- Each product has its own distinct functional strengths and weakness.
- Each product has its own unique architecture differentiators, such as the ability to perform and scale as needed.
- Each product is implemented with differing technologies that the utility IT department has to support and integrate with other applications in the enterprise.
- Some products have service-based architectures at the enterprise level; others do not.
- Some products have well-defined interfaces and points of interoperability; others do not.
- Some products meet industry and international standards; others do not.
- Some products adhere to Smart Grid principles;[84] others do not.
- In addition, each vendor is unique in its level of product development maturity and implementation experience and expertise.

Utilities are encouraged to find the solutions that best fit their needs—in the present and foreseeable future.

[84] As envisioned by Smart Grid researchers such as EPRI, the California Energy Commission's Public Interest Energy Research program, the Modern Grid Initiative, and DOE's GridWise program.

Vendor List

Aclara Software

- Energy Vision®
- http://www.aclaratech.com/software/

Advanced AMR Technologies, LLC

- 8800 Energy Information and Control System
- http://www.advancedamr.com/

American Innovations Ltd.

- AIMetering System®
- http://www.aimonitoring.com

BPL Global

- Power SG™ Theft Detection
- http://www.bplglobal.net/

Detectent, Inc.

- Revenue Enhancement Suite
- http://www.detectent.com/

E-Mon LLC

- E-Mon Energy™
- http://www.emon.com

Echelon Corporation

- Networked Energy Services
- http://www.echelon.com

Ecologic Analytics, LLC

- WACS Meter Data Management System
- http://www.ecologicanalytics.com/

EKA Systems, Inc

- Energy Insight
- http://www.ekasystems.com

Elster Electricity, LLC

- EnergyAxis® System
- http://www.elsterelectricity.com

eMeter Corporation

- eMeter's Consulting and Implementation Services
- http://www.emeter.com/

EnergyICT Inc.

- COMServerJ
- http://www.energyict.com

Enerwise Global Technologies, Inc

- Metering & Integration
- http://www.enerwise.com

Envision Utility Software Corporation

- foCIS™
- http://www.envworld.com

IBM Corporation

- Asset Monitoring and Advanced Metering
- http://www.ibm.com/us/

InStep Software, LLC

- Enterprise Energy Management Software
- http://www.instepsoftware.com

Itron

- Enterprise Edition Customer Care
- http://www.itron.com

MeterSmart

- Meter Data Management
- http://www.metersmart.com

Metretek Inc.

- DC2000
- http://www.metretekfl.com/

MU Net, Inc.

- WebGate® System
- http://www.munet.com

Neptune Technology Group Inc.

- FIELDNET®
- http://www.neptunetg.com

Oracle

- Oracle Utilities Meter Data Management
- http://www.oracle.com/industries/utilities

OZZ Corporation

- Meter Data Management Solutions
- http://www.ozzcorp.com

Powel, Inc.

- Meter Data Management
- http://www.powel.com/

Power Measurement

- EEM Systems
- http://www.pwrm.com/

SAP America, Inc.

- SAP Enterprise Data Management
- http://www.sap.com/usa/industries/utilities/index.epx

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Results of Modifications to AMI Business Plan BCA

Changes	SCT BCA ratio Opt-In Low	SCT BCA ratio Opt-In High	SCT BCA ratio Opt-Out Low	SCT BCA ratio Opt-Out High
Company Results	0.96	1.05	1.20	1.56
Reduce Discount Rate	0.97	1.07	1.22	1.60
Update Capacity Prices	0.94	1.00	1.10	1.33
Change AMR replacement Schedule	0.90	0.96	1.06	1.29
Update Price of CO2	0.89	0.95	1.04	1.26
Add CO2 Benefit for CVR	0.90	0.96	1.06	1.28
Reduce incremental CRV .5%	0.89	0.94	1.04	1.26
Adjust VVO Roll-out Schedule	0.88	0.94	1.04	1.26
Change TVP assumptions	0.86	0.89	0.92	1.00
Remove Green Button and E-Commerce	0.88	0.91	0.94	1.03

		Staff Proposed Changes to BCA			
Category	Deployment Period Capital Cost	20 Year 6.17% NPV (FY19$) Opt-in Lo	20 Year 6.17% NPV (FY19$) Opt-in Hi	20 Year 6.17% NPV (FY19$) Opt-out Lo	20 Year 6.17% NPV (FY19$) Opt-out Hi
AMI Meter and Installation Cost Table 4-1					
AMI Electric Meter Equipment and Installation	$ 293.74	$ 225.47	$ 225.47	$ 225.47	$ 225.47
AMI Gas ERT Equipment and Installation	$ 73.50	$ 56.79	$ 56.79	$ 56.79	$ 56.79
AMI Inventory	$ 6.25	$ 4.78	$ 4.78	$ 4.78	$ 4.78
Support Infrastructure	$ 18.37	$ 13.63	$ 13.63	$ 13.63	$ 13.63
Total	**$ 391.86**	**$ 300.67**	**$ 300.67**	**$ 300.67**	**$ 300.67**
Communications Network Equipment and installation Table 4-2					
Network Equipment and Installation	$ 6.06	$ 8.29	$ 8.29	$ 8.29	$ 8.29
Communication Network Installation Management	$ 9.49	$ 8.42	$ 8.42	$ 8.42	$ 8.42
Backhaul	$ -	$ 2.98	$ 2.98	$ 2.98	$ 2.98
Total	**$ 15.55**	**$ 19.69**	**$ 19.69**	**$ 19.69**	**$ 19.69**
Platform and Ongoing IT Operations Costs Table 4-3					
Total	**$ 166.11**	**$ 225.76**	**$ 225.76**	**$ 225.76**	**$ 225.76**
Project Management and Ongoing Business Operations Cost Table 4-4					
Project Management	$ 4.15	$ 11.72	$ 11.72	$ 11.72	$ 11.72
Equipment and Installation Refresh Cost	$ 0.54	$ 8.91	$ 8.91	$ 8.91	$ 8.91
Oning Business Management	$ -	$ 25.83	$ 25.83	$ 25.83	$ 25.83
Customer Engagement Cost	$ -	$ 26.29	$ 26.29	$ 26.29	$ 26.29
Total	**$ 4.69**	**$ 72.76**	**$ 72.76**	**$ 72.76**	**$ 72.76**
Total Cost	**$ 578.21**	$ 618.88	$ 618.88	$ 618.88	$ 618.88
Avoided O&M Costs Table 5-1					
AMR Meter Reading		$ 49.37	$ 49.37	$ 49.37	$ 49.37
Meter Investigation		$ 5.90	$ 5.90	$ 5.90	$ 5.90
Remote Connect and Disconnect		$ 61.56	$ 61.56	$ 61.56	$ 61.56
Reduction in Damage Claims		$ 10.25	$ 10.25	$ 10.25	$ 10.25
Total		**$ 127.08**	**$ 127.08**	**$ 127.08**	**$ 127.08**
Avoided AMR Costs Table 5-2					
Capital		$ 245.98	$ 245.98	$ 245.98	$ 245.98
Operations & Maintenance		$ 12.68	$ 12.68	$ 12.68	$ 12.68
Total		**$ 258.67**	**$ 258.67**	**$ 258.67**	**$ 258.67**
Customer Benefits Table 5-8					
Volt-Var Optimization		$ 14.24	$ 14.24	$ 14.24	$ 14.24
Energy Insights/High Usage Alerts		$ 57.76	$ 57.76	$ 57.76	$ 57.76
Time Varying Pricing		$ 16.81	$33.61	$47.62	$95.23
Total		**$ 88.81**	**$ 105.61**	**$ 119.62**	**$ 167.23**
Societal Benefits (CO2 Emmission Reductions) Table 5-9					
AMR Meter Reating		$ 8.20	$ 8.20	$ 8.20	$ 8.20
Meter Investigations		$ 2.96	$ 2.96	$ 2.96	$ 2.96
Remote Connect and Disconnect		$ 35.37	$ 35.37	$ 35.37	$ 35.37
Energy Insights/High Usage Alerts		$ 18.48	$ 18.48	$ 18.48	$ 18.48
Time Varying Pricing		$ 3.06	$6.12	$8.68	$17.35
CO2 Reduction from Incremental CVR		$ 4.66	$ 4.66	$ 4.66	$ 4.66
Total		**$ 68.07**	**$ 71.13**	**$ 78.35**	**$ 82.36**
Revenue Benefits Table 5-10					
Reduction in Theft of Service		$62.73	$62.73	$62.73	$62.73
Reduction in Write-offs and Inactive Meter Consumption		$96.07	$96.07	$96.07	$96.07
Total		**$ 158.80**	**$ 158.80**	**$ 158.80**	**$ 158.80**
Total Benefits		**$ 701.43**	**$ 721.30**	**$ 742.52**	**$ 794.15**
Net Benefit		**$ 82.55**	**$ 102.42**	**$ 123.64**	**$ 175.27**
Benefit to Cost Ratio		1.13	1.17	1.20	1.28
SCT Benefit to Cost Ratio		0.88	0.91	0.94	1.03

Category	Deployment Period Capital Cost	Company Proposal 20 Year 6.85% NPV (FY19$) Opt-in Lo	20 Year 6.85% NPV (FY19$) Opt-in Hi	20 Year 6.85% NPV (FY19$) Opt-out Lo	20 Year 6.85% NPV (FY19$) Opt-out Hi
AMI Meter and Installation Cost Table 4-1					
AMI Electric Meter Equipment and Installation	$ 293.74	$ 219.16	$ 219.16	$ 219.16	$ 219.16
AMI Gas ERT Equipment and Installation	$ 73.50	$ 55.23	$ 55.23	$ 55.23	$ 55.23
AMI Inventory	$ 6.25	$ 4.64	$ 4.64	$ 4.64	$ 4.64
Support Infrastructure	$ 18.37	$ 13.26	$ 13.26	$ 13.26	$ 13.26
Total	**$ 391.86**	**$ 292.30**	**$ 292.30**	**$ 292.30**	**$ 292.30**
Communications Network Equipment and installation Table 4-2					
Network Equipment and Installation	$ 6.06	$ 7.94	$ 7.94	$ 7.94	$ 7.94
Communication Network Installation Management	$ 9.49	$ 8.19	$ 8.19	$ 8.19	$ 8.19
Backhaul	$ -	$ 2.77	$ 2.77	$ 2.77	$ 2.77
Total	**$ 15.55**	**$ 18.90**	**$ 18.90**	**$ 18.90**	**$ 18.90**
Platform and Ongoing IT Operations Costs Table 4-3					
Total	**$ 166.11**	**$ 226.64**	**$ 226.64**	**$ 226.64**	**$ 226.64**
Project Management and Ongoing Business Operations Cost Table 4-4					
Project Management	$ 4.15	$ 11.47	$ 11.47	$ 11.47	$ 11.47
Equipment and Installation Refresh Cost	$ 0.54	$ 8.28	$ 8.28	$ 8.28	$ 8.28
Oning Business Management	$ -	$ 24.18	$ 24.18	$ 24.18	$ 24.18
Customer Engagement Cost	$ -	$ 25.61	$ 25.61	$ 25.61	$ 25.61
Total	**$ 4.69**	**$ 69.55**	**$ 69.55**	**$ 69.55**	**$ 69.55**
Total Cost	**$ 578.21**	**$ 607.38**	**$ 607.38**	**$ 607.38**	**$ 607.38**
Avoided O&M Costs Table 5-1					
AMR Meter Reading		$ 45.78	$ 45.78	$ 45.78	$ 45.78
Meter Investigation		$ 5.47	$ 5.47	$ 5.47	$ 5.47
Remote Connect and Disconnect		$ 57.08	$ 57.08	$ 57.08	$ 57.08
Reduction in Damage Claims		$ 9.46	$ 9.46	$ 9.46	$ 9.46
Total		**$ 117.79**	**$ 117.79**	**$ 117.79**	**$ 117.79**
Avoided AMR Costs Table 5-2					
Capital		$ 254.35	$ 254.35	$ 254.35	$ 254.35
Operations & Maintenance		$ 21.24	$ 21.24	$ 21.24	$ 21.24
Total		**$ 275.60**	**$ 275.60**	**$ 275.60**	**$ 275.60**
Customer Benefits Table 5-8					
Volt-Var Optimization		$ 21.76	$ 21.76	$ 21.76	$ 21.76
Energy Insights/High Usage Alerts		$ 53.62	$ 53.62	$ 53.62	$ 53.62
Time Varying Pricing		$ 42.45	$ 91.35	$ 169.78	$ 365.39
Total		**$ 117.83**	**$ 166.73**	**$ 245.16**	**$ 440.77**
Societal Benefits (CO2 Emmission Reductions) Table 5-9					
AMR Meter Reating		$ 7.62	$ 7.62	$ 7.62	$ 7.62
Meter Investigations		$ 2.75	$ 2.75	$ 2.75	$ 2.75
Remote Connect and Disconnect		$ 32.88	$ 32.88	$ 32.88	$ 32.88
Energy Insights/High Usage Alerts		$ 23.48	$ 23.48	$ 23.48	$ 23.48
Time Varying Pricing		$ 5.99	$11.97	$23.94	$47.89
CO2 Reduction from Incremental CVR					
Total		**$ 72.72**	**$ 78.70**	**$ 90.67**	**$ 114.62**
Revenue Benefits Table 5-10					
Reduction in Theft of Service		$58.16	$58.16	$58.16	$58.16
Reduction in Write-offs and Inactive Meter Consumption		$88.91	$88.91	$88.91	$88.91
Total		**$ 147.07**	**$ 147.07**	**$ 147.07**	**$ 147.07**
Total Benefits		$ 731.00	$ 785.89	$ 876.30	$ 1,095.85
Net Benefit		**$ 123.62**	**$ 178.50**	**$ 268.91**	**$ 488.47**
Benefit to Cost Ratio		1.20	1.29	1.44	1.80
SCT Benefit to Cost Ratio		0.96	1.05	1.20	1.56

Appendix 18 - Advanced Metering Infrastructure (AMI) Scorecard / Metrics

Category	Service/Function	Metric	Description	Target	Report Start Date	Update Frequency
Customer Engagement	Energy Savings Messages / Tools	Customers using the AMI Portal	Percentage of customers in each region with AMI meters that log on to usage/analytics page (available via web, mobile web, tablet or apps) at least once during the reporting period, broken down by service class and low income / non-low income. Baseline established based on data from at least the first 6 months of deployment in each region. Improvement measured against regional baselines each reporting period. Additional reporting (no targets established): Percentage of customers that logged on more than once during each reporting period.	To be set once-baseline has been established for each region, and following Staff review.	4/30/2018	Semi annual
		Customers targeted with energy saving messaging	Percentage of customers with AMI meter at least 30 days that are targeted during the reporting period with messages regarding their energy savings tools, personalized usage and/or savings tips. Data broken out by low income and non-low income. Additional reporting (no targets established): If possible, Company will track and report for each reporting period the number of customers that use the online portal once they receive targeted messaging.	Percentage of customers that will be targeted will be established after Staff review and prior to initial report on 4/30/2018.	4/30/2018	Semi annual
		Near-Real Time Data	Number of customers with an AMI meter that have access to near real-time data via the web, mobile web, tablet or apps.	Starting at end of 3Q2018, 99% of meters deployed will be presented with near real time data. Refer to roll-out plan for quantities on a quarterly basis.	4/30/2019	Semi annual
	Awareness / Education	Customer Awareness of AMI*	Customer awareness of AMI technology, features and benefits, measured by surveys of customers in each region. Baseline established on a regional basis prior to roll-out of AMI in each area (March 2017 for Staten Island). Subsequent progress ("check-in surveys") measured semi-annually, beginning at least 6 months after the beginning of deployment, through the end of roll-out in each region. Check-in surveys will draw from customers with AMI meters only. In the post-deployment surveys, the Company will measure low-income awareness. See Note 3 below.	To be set for each region following baseline surveys that will be done three months prior to-the deployment. Staff will review.	4/30/2018	Semi annual

Category	Service/Function	Metric	Description	Target	Report Start Date	Update Frequency
Customer Engagement	Awareness / Education	Targeted Energy Forum	Con Edison hosted forums where the Company will provide in-depth information on the AMI plan, features, and benefits.	2 per region. Staff will review.	4/30/2018	Annual
	Green Button Connect My Data	Green Button Connect My Data	Number of customers who share their data via GBC in the reporting period plus number of customers that continue to share based on elections made in a prior period. Establish baseline using calendar year 2018 data.	To be set once baseline has been established, and following Staff review.	4/30/2019	Semi annual
	TOU (Time of Use) and TVP (Time Variable Pricing) tariffs	Customer Adoption of Time-Variant Rates	Number of customers with AMI meters that adopt a TOU or TVP tariff, expressed as a number and percentage of each by rate (e.g., Electric SC1 Rate III, Electric SC2 Rate II, pilot rates, etc.). The Company will document the number of customers on existing TOU or TVP rates prior to the start of AMI roll-out, for comparison purposes.	Company will report this information for tracking purposes only.	4/30/2018	Semi annual
	Community Outreach	Community Organization Events	Number of organizational events attended where information on AMI plan, features, and benefits would be presented.	20 presentations per year. With a minimum of 4 per region in each year until the conclusion of deployment in that region.	4/30/2018	Semi annual
Billing	Billing	Estimated Bills	Percentage of bills that were estimated for accounts with AMI meters during the reporting period.	< 1.5 % of bills will be estimated for customers with AMI	4/30/2018	Semi annual
Outage Management	Power Quality	Proactive power quality issue identification	Reduction in truck rolls due to power quality complaints.	500 per year after full deployment of AMI in 2022.	4/30/2018	Annual
	False Outages	Number of false outages resolved through AMI	Number of false outages that were found through AMI that Company did not have to send a crew or call to confirm.	9000 per year once AMI is fully deployed in 2022.	4/30/2018	Annual
	Meter Reading Costs	Reduction in manual meter operations costs	Track avoided meter operations O&M costs and report.	In accordance with O&M reductions filed in the 2016 Rate Case.	4/30/2018	Annual
	Environmental benefits resulting from less vehicle usage	Reduction in vehicle fuel consumption and vehicle emissions	Reduction in vehicle fuel consumption and vehicle emissions due to reduction in manual meter reading costs, reduction in false outages and reduction in number of field visits during outages to confirm a customer has power.	This goal will be aligned with the information provided in the November 2015 Business Plan on tons of carbon avoided.	4/30/2018	Annual

Category	Service/Function	Metric	Description	Target	Report Start Date	Update Frequency
System Operation and Environmental Benefits	Conservation Voltage Optimization (CVO)-Networks	Number of networks deployed with CVO	Number of networks with AMI deployed and have implemented CVO.	Substation voltage schedules will be updated to incorporate the AMI feedback loop within one year following the installation of all AMI meters associated with that station. Note that for this reason, kWH reductions noted below cannot be reported on until mid-2019.	10/31/2018	Semi annual
	Conservation Voltage Optimization (CVO)-KWh savings	Quantify kWh savings attributed to CVO	Quantify kWh savings attributed to CVO.	Goal is 1.5% energy savings based on calculations verified using a similar measurement and verification process as used for Brooklyn/Queens Demand Management project, subject to future changes in load composition.	10/31/2019	Annual
	Conservation Voltage Optimization (CVO)-Environmental benefits	Environmental benefits due to CVO	Provide total fuel consumption savings and corresponding emissions reductions.	By the end of 2022, reduction in fossil fuel consumption resulting in CO2 emission reductions of 229,000 metric tons in the CECONY service area and 369,000 metric tons in all of New York State annually, subject to changes in generation fuel mix and imports/exports with neighboring pools.	10/31/2019	Annual
AMI Meter Deployment	Number of AMI meters installed	Number of AMI meters installed	Provide the number and percentage of AMI meters installed and working by borough and in Westchester. Information will be provided on a quarterly basis.	See Note 4 for target.	4/30/2018	Semi annual

Note 1 : Twelve months after AMI installation has been completed in each region, the Company will perform a survey to examine the link, if any, between AMI deployment and Distributed Energy Resource adoption. Results of this study will be provided at the next scheduled reporting interval.

Note 2 : The Company will file two reports in each calendar year, six months apart, with the Secretary to the Commission. The reports will contain Con Edison's eligibility for an Earnings Adjustment Mechanism (EAM) and Scorecard information. Information regarding the Company's eligibility for the EAM will be included in the report submitted after the post-deployment survey results are available; and this report will (1) provide the results from the customer surveys and (2) identify whether an earnings adjustment is applicable and the amount of the earnings adjustment.
All reports will no longer be required following the last reporting interval after completion of the AMI deployment.

Note 3 : In the post-deployment survey performed for each region, the Company will measure low income customer awareness. Results will be provided at the next scheduled reporting interval.

Note 4 : AMI Rollout Plan from Con Edison's November 2015 Benefit Cost Analysis spreadsheet, with exception for Westchester which has been accelerated from what was proposed in November 2015 Benefit Cost Analysis spreadsheet.

AMI Meter Deployment (000s)							
Quarter/Year	Staten Island	Westchester	Brooklyn	Manhattan	Bronx	Queens	Total
Q3 2017	32						32
Q4 2017	60	30					90
Q1 2018	60	60					120
Q2 2018	30	90	30				150
Q3 2018		90	60	30			180
Q4 2018		90	90	60			240
Q1 2019		90	90	90	30		300
Q2 2019		90	90	90	60		330
Q3 2019		40	90	120	75	5	330
Q4 2019		25	90	120	75	30	340
Q1 2020			90	120	75	60	345
Q2 2020			90	90	75	90	345
Q3 2020			90	90	75	90	345
Q4 2020			90	90	75	90	345
Q1 2021			60	60	75	150	345
Q2 2021			18	60	75	150	303
Q3 2021			6	60	75	150	291
Q4 2021			4	30	22	150	206
Q1 2022				30		40	70
Q2 2022				4		4	8
Total	182	605	988	1144	787	1009	4715