Enabling Price-Responsive Demand Response using Legacy Load Management Technologies

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ABSTRACT

Millions of existing homes and small commercial establishments have load control devices installed on central electric air-conditioning equipment and other significant electricity-using end-use devices (e.g., electric water heaters and pool and fountain pumps). In the currently popular industry-wide discussions and debates about the “smart grid,” “advanced metering infrastructure,” “dynamic pricing,” and “demand response (DR),” there is little talk of how we might bring the benefits of dynamic pricing and customer choice, control and response to these legacy system participants without abandoning and replacing the existing devices. This paper’s goal is to start this conversation.

The paper discusses the informational and technological requirements needed for legacy load-management system participants to be able to introduce their own chosen responses to critical pricing or reliability events that may confront their electricity supplier.

Given these informational and technological requirements are satisfied, the paper then presents several illustrative demand response program designs that will well mimic technology-enabled dynamic pricing using the existing deployment of one-way load control switches and programmable communicating thermostats.

The basic premise for the conversation is that it may be possible to achieve with these legacy load-management system participants, most of the benefits of technologically enabled dynamic pricing without having to bear the added costs of load management equipment replacement and an advanced metering infrastructure. Although, there may be other very good reasons for deploying new metering.

Legacy One-Way Networks of Residential Load Management Devices

Today there are more than five million residential customers allowing utilities the direct load control of significant electrical end-uses (FERC 2008, 25). These end-uses are central electric air-conditioning, electric water heating, and, to a much smaller extent, pool, fountain and irrigation pumps.

These programs are old. The Electric Power Research Institute (EPRI) credits Detroit Edison as the first to implement a load control program, starting one in 1968 (EPRI 1985). Many believe water heater “timer” programs and programs using “ripple control,” an early power line carrier communications technology, made appearances in the United States and elsewhere soon after the end of World War II.

These programs have staying power. Detroit Edison’s program, started 41 years ago, is still the fourth largest load management program in the United States with more than 280,000 enrolled residential customers (FERC 2008, XLS). Great River Energy, through its member cooperatives, may have been doing load control of electric water heating longer and more than 100,000 of its residential customers are still participating (FERC 2008, XLS). Many utilities sponsoring these programs rely on them to help manage reliability events—helping avoid or mitigate voltage reductions (brown outs) and reduce blackout likelihoods. Some use these programs to help lower peak-period purchased power costs or to defer the need for additional peaking capacity. The Federal Energy Regulatory Commission recently reported that direct load control (DLC) programs are cost beneficial for 48 of the 50 states, failing the test in only two states, Alaska and Hawaii, and passing easily everywhere else (FERC 2009, 242).[1] Table 1 (FERC 2008, XLS) presents 2008's seven largest residential DLC programs and some salient details about them.

Table 1. Seven Largest DLC Programs in U.S.

Utility	Program Type	Customers Enrolled	% Customers Enrolled
Florida Power & Light	DLC AC, WH, & PP	761,569	19.1%
Northern States Power	DLC AC & WH	337,216	25.6%
Southern California Edison	DLC AC	283,836	7.2%
Detroit Edison	DLC AC	282,433	14.7%
Progress Energy Florida	DLC AC, WH, & PP	237,414	16.4%
Baltimore Gas & Electric	DLC AC	235,508	21.2%
Duke Energy Carolinas	DLC AC	223,558	11.0%

How Legacy One-Way Residential DLC Programs Work

Legacy residential load management programs, also known as load control programs or direct load control (DLC) programs, consist of load management devices connected to major end-use loads; e.g., central electric air conditioning, electric water heating, and, infrequently, pool, fountain and irrigation pumps.

Switches, also known as relays and often called by the nomenclature used by the device manufacturers, receive instructions to restrict or modify the normal operation of the end-use technology for the duration of a control event initiated by a utility through its network management software known as a "head end." Many legacy programs use switches for the direct load control of the above listed residential end-uses.

For the control of central electric air conditioning, some legacy programs rely on one-way programmable communicating thermostats (PCTs). These programs provide participating customers with an advanced programmable thermostat in exchange for the right to modify the operation of the air conditioner during control events. These PCTs allow utilities "cycling" control and temperature set-point modifications.

In legacy load management programs, utilities communicate with installed switches and PCTs using one of three types of communications media; power line carrier (not available for PCTs), VHF paging (usually 152 to 154 MHz), or UHF paging (e.g. 900 MHz Motorola Flex™). The load management devices receive the control messages and respond to them in accordance with their programmed instructions.

Many of the legacy load management devices have internal "logging" capabilities. They log things like time synchronizations, air conditioner runtime, receipt of control messaging, and other things including for some PCTs, indoor temperature. Extracting these data logs for analysis normally requires site visits by trained installation personnel.

An important technical feature of nearly all one-way load management devices deployed in North America is that each device is individually addressable. Individual addressability is important because it is sometimes necessary to remove a participant from a control event or to deactivate specific devices. In addition, as I will soon explain, if the utility desires to "modernize" its legacy program design to include features of customer-choice and price-responsiveness, utilities will need this functionality.

[1] Interestingly in Hawaii, failing with a benefit to cost ratio of 0.93, Hawaii Electric Company (HECO) runs a significant residential direct load control program directed at electric water heating and central electric air conditioning. For HECO an important value derived from the program is the automated under-frequency control provided by the load management devices. Frequency control is more of an issue for Hawaii because, as an island, they are not interconnected. This added value tips the cost-benefit scale in the program's favor.

The Growth of the Internet

Of the more than 300 million people in the United States, 230 million of them use the Internet. In 2008, 80.6% of households had a computer and 92% of those had Internet access—up from 77.9% a year earlier. Multiplying the 80.6% of households with a computer by 92% yields 74%—the percentage of households with Internet access in 2008, 57% have "high speed" access and 17% have "dial-up" (Nielsen 2008, 1).

The growth rate of the Internet exceeds that of any previous technology. Measured by users and bandwidth, the Internet has been growing at a rapid rate since its conception, on a curve geometric and sometimes exponential. Former U.S. President Clinton said, "[w]hen I took office only high energy physicists had ever heard of what is now called the World Wide Web…Now even my cat has its own page."[2] President Elect Obama's campaign Web site stated, "Obama and Biden believe we can get true broadband to every community in America" (Nielson 2008, 1). The Nielson paper also asserts, "[a]s a country, we have ensured that every American has access to telephone service and electricity, regardless of economic status, and Obama will do likewise for broadband Internet access" (Nielson 2008, 1).

Regardless of who gets the credit (Obama, Al Gore, or competitive market forces), it seems clear that the Internet will soon be a part of everyone's life, if it is not already. This is good news for those utilities seeking a makeover for their legacy one-way networks of load management devices.

Price-Responsive DR Goals

If it is possible (and it will soon be clear that it is) to offer customers a "dynamic pricing" program using an existing one-way load management infrastructure, why do it? The answer is multifold: Economics plays a role. Grid operations and reliability concerns play a role. Customers' values, what they want from electricity service, also play a role.

A Role for Economics

It is a well-known fact that the cost of making, transmitting and distributing electric energy to customers varies continuously with time and, as we have learned from the work on locational marginal pricing, with space or geography.

The right purpose for prices is to motivate the economically efficient use of good and services, including things like electric service. For prices to do that job well, they need to reflect the cost of supplying the products to which the prices apply. For electricity, this means prices would need to vary with time and space in the same way supply costs do.

This is not even close to a new idea. The principle has been known for more than two centuries. People in the electricity business have understood it from the days of Sam Insull and they have understood the principle better than many people in other industries have. Our trade magazine, Public Utilities Fortnightly, has been around since the very early twentieth century. A perusal of early issues of that magazine will establish the point.

Electricity is still one of the very few products or services supplied (dispatched, if you prefer) almost exclusively based on real-time marginal cost but rarely is it priced on that basis.

If electricity is to be priced the same way it is "cost-ed", you have to be able to meter/measure consumption–where it occurs—more or less continuously and store or remember those readings. You also must have the systems available to manage and use the collected data—primarily for billing purposes. You, therefore, must also have robust billing systems. Most importantly, your mass-market customers must be willing to accept and manage a dynamic pricing scheme for electricity service.

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[2] This appears at the site, http://www.internetworldstats.com/emarketing.htm.

Emerging AMI and meter-data management systems may solve the technical problems associated with dynamic pricing, but whether mass-market customers will accept dynamic pricing schemes, is still an open question.

Grid Operations and Reliability

Unfortunate events happen: Generation plants experience forced outages. Transmission lines go down. Substations fail. Sometimes events like these call for some immediate load relief. The purpose of legacy load management is to respond quickly to these events.

Real-time pricing and critical peak pricing have shown that when customers face high prices, they also respond by reducing load—reducing more when technologically enabled. Therefore, "dynamic pricing" programs like critical peak pricing, offer grid operators another tool to manage grid operations and reliability.

What Mass-Market Customers Value from Electricity Service

In addition to low cost and reliability, "control" is a desired quality that consumers want. Market research surveys reveal that many customers do not "feel" in control of their electric bill. Sure, they control the light switches but they do not clearly connect lighting and appliance use to billing consequences.

Legacy one-way load management programs ask participants to relinquish some control of certain significant end-uses; such as central air conditioning, electric water heating, and pool or fountain pumps. In exchange, participants typically receive some money and the knowledge they are "helping." These programs are able to attract only a fraction of those eligible to participate. Typical one-way load management programs, if aggressively marketed, attract between 20 and 40% of eligible customers. This leaves 60 to 80% choosing not to participate. Many of these are unwilling to relinquish control of major end-use loads, even for limited times, to their electric utility.

By introducing a "customer-choice" or "dynamic pricing" flavor to legacy one-way load management programs, these programs may appeal to a broader audience of eligible customers, and the programs may grow—increasing the amount of potential and realizable peak load reduction.

Price-Responsive DR Receptivity

Customer tolerance for highly variable prices is low among ordinary members of the mass-market. Time-of-use pricing schemes, off-peak pricing discounts, seasonally adjusted rates, and combinations of these have been around for decades. In the mid 1960s through the mid-1970s, utilities conducted many dozens of TOU pricing experiments. In many places, they implemented optional, in a few places mandatory, residential TOU rates, and they measured their impacts. The results of this research were remarkably consistent and are well-summarized by a statement made in a Christensen & Associates study done for the Illinois Commerce Commission in the late 1970s: the benefits of TOU pricing do not cover the cost of the required metering (Caves 1982).

Why would that have been the case? Electricity costs, however annoying they may be, are still a small part of a household's total budget. It is insufficient to reduce an electric bill by 10% or so for most households to take the trouble to remember the TOU schedule. They will not take the time and effort required to either manually adjust the thermostat at the scheduled times or buy a programmable thermostat that, once programmed, would remember for them and automatically do the adjusting. For residential customers, the "full" cost (not just the monetary cost) of responding to TOU rates was simply too high in relation to the financial penalties imposed by TOU rates.

Significantly reducing the "full" cost of responding is imperative for dynamic pricing to work effectively with mass-market consumers of electricity. Jim Rogers of Duke Energy tells us that electricity consumption is a "back-of-mind" activity. It has to be easy and mindless for people to respond to electricity price changes, by predetermining and preprogramming those responses. In short, technologically enabling mass-market price-responsive DR programs is necessary.

Price-Responsive DR Infrastructure Needs

There are four price-responsive DR infrastructure requirements:

- A means to rapidly communicate rate changes and critical peak conditions to program participants
- A means of recording and retrieving the requisite billing determinants; i.e., an interval meter
- A way for participating customers to predetermine and program their demand responses in advance of the pricing event; e.g., "If the price exceeds 15¢ per kWh then reset my thermostat's set point to 80° and make sure my electric water heater and pool pump do not operate."
- A way to implement predetermined demand responses automatically when notified of impending price changes

We need all of these elements if dynamic pricing is to bring significant DR from mass-market consumers of electricity. Dynamic pricing cannot approximate efficient pricing unless these elements exist. These infrastructure elements will cost money and for some systems of dynamic pricing, the facilitating equipment will cost quite a lot of money.

In combination with the near ubiquity of the Internet, the individual addressability of one-way load control switches and PCTs, the increasingly lower prices for interval meters and the widespread implementations of AMR and AMI, legacy networks for DLC meet these infrastructure requirements.

Customer-Choice and Price-Responsive DR Program Design

In the following sections, I examine customer-choice and price-responsive DR program designs for networks of one-way DLC switches and PCTs. Many more load control switches are deployed than are PCTs but since PCTs provide a wider set of DR program design options than do switches, it is better to discuss them separately.

Customer-Choice and Price-Responsive DR Program Designs for One-Way DLC Switches

If a utility wanted to, it could design an air conditioning demand response program that allowed customers to choose a cycling option; e.g., 25%, 33%, 50%, 67% or 75%. Load management network "head-end" software can easily manage a network of DLC switches where the participants have chosen different cycling strategies and since each switch has a unique address–communicating the customer-chosen strategy to the individual switches is accomplished easily. If a utility wanted to, it could allow customers to change their selected cycling option whenever they desired.

Most legacy DLC switches and "head-end" software will support program designs allowing control event "opt-outs" or the paying of incentives based on the severity of the customer-chosen control strategy.

Legacy one-way DLC switches and "head-end" software will support program designs that, to my knowledge, are untried. For example, many control events are called in the mid- to late-afternoon periods of summer workdays. Many dual income households are not at home then. I can envision a program where participants can choose a more severe control strategy for those times when they are not at home and a less severe one for those times when they are at home; e.g., not at home, 80% off – 20% on; at home, 40% off – 60% on. This option would substantially increase the available demand response for those mid- to late-afternoon control events and may well make a program more attractive to certain residential customers who would not otherwise enroll.

A dynamic pricing program should allow customers to elect different strategies that depend directly on the expected price for electricity in a future hour. Allowing customers to choose the severity of their cycling strategy as a function of both their lifestyle and the expected price of power makes a switch-based price-responsive program practically indistinguishable from one based on PCTs.

The point is, if your utility has a legacy one-way network of load management switches and you would like to expand the appeal of your program to both existing participants and non-participants, then you can add customer-choice options. The options you offer may or may not depend on price. Customers want to feel more in control and by introducing customer-choice features into your existing load management program design you will broaden the appeal of your program and gain more peak load reduction.

Customers are different: Some will prefer the status quo. Some will change from the control strategy you currently use. Some will enroll for the first time. All participants will be happier with the program because it provides them with more flexibility—allowing them to choose the load management option best suited to their lifestyles and pricing sensitivities.

Utilities with legacy one-way load management systems can achieve all this without having to change their load management equipment, equipment provider, or "head-end" software. Customers can make their elections via the Internet, mail-in ballot, or a phone conversation with a customer service representative. Updating the participant database to reflect these elections is easy and, since all devices are individually addressable, accurately implementing these choices is easy too.

Customer-Choice and Price-Responsive DR Program Designs for One-Way PCTs

Since the early 2000s, some utilities' demand response programs have included page-receptive PCTs. Many of these PCTs can cycle air conditioners very much like a load management switch and these PCTs also permit temperature setback strategies with or without pre-cooling. These PCTs can often display the price tiers for a typical four-tiered critical peak pricing (CPP) rate design. Because the PCTs are individually addressable, participants can program them using the Internet.

Participants in a CPP program would navigate to a screen and input their preferred responses to critical price events. Their programmed instructions for responding to critical price events as well as their desired settings based on lifestyle guided perhaps by a time-of-use rate design are communicated to their PCTs in accordance with Figure 1 below.

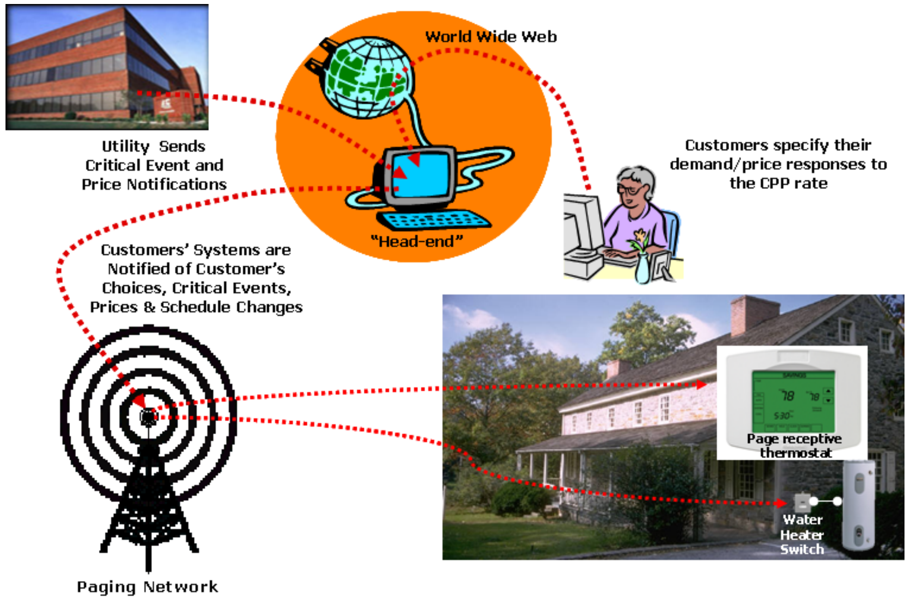

Figure 1 - Simple One-Way CPP Configuration

This illustration is of a simple one-way approach to CPP using the UtilityPRO™ PCT for HVAC control and load management switches for water heater or pool pump control. This illustration displays what I consider the minimum necessary infrastructure to create and implement CPP in a manner that promises to bring value to participants and demand response to the sponsoring utility.

If utilities have deployed one-way systems of load management relying partly on PCTs and are using those PCTs simply to cycle air conditioners during critical events, those utilities can easily offer their customers a CPP option. By so doing, they may bring others into their programs that were previously reluctant to enroll. They may also increase the satisfaction of existing participants by providing them with new customer-choice options.

CPP participants require an interval data recorder — its readings gathered at least monthly for billing purposes. Software can then "bucket" these hourly readings into the appropriate rating periods defined by the CPP rate. The meter readings can however be gathered in any economical way–remotely or by meter readers.

One-way PCTs allow for all the program design options discussed above for one-way DLC switches and other options that involve changing the temperature set points or, perhaps, offering a typical four-tiered CPP rate. I believe the number of program designs possible using one-way load management devices is very large, limited only by the imaginations of program designers.

Price-Responsive DR and Load Management Issues

Customers' Demand Response Program Preferences

Customer-controlled programs, using either one-way PCTs or one-way DLC switches, will appeal to some people and utility-controlled programs (e.g., A/C cycling) will appeal to others. This fact should present no worries to program designers. Kenmore makes different models of refrigerators to appeal to different segments of the refrigerator-buying public. Having different types of demand response programs should be no different. Many residential customers, when given the choice between a page-receptive programmable thermostat and a DLC switch allowing the utility to cycle their central air conditioners, choose the DLC switch. There is no one universally preferred load management technology.

One-way vs. Two-way Demand Response Solutions

Some utilities want two-way programmable communicating thermostats (PCTs) for their planned mass-market demand response programs. Responding to this demand, companies are developing and marketing PCTs with two-way communications capabilities. These two-way PCTs have yet to gain any material traction in the marketplace because other requisites for their operation are only slowly developing (e.g., ZigBee® communicating AMI meters).

One-way vs. Two-way M&V Considerations

People often ask; with a one-way network of load control devices, how can we be sure we are getting the demand response we are paying for?

With an exemplar sample of sufficient size and perhaps equipped with end-use metering, the aggregate amount of demand response achieved during any control event can be estimated to any desired degree of accuracy—typically a 90% to 95% level of confidence in a 5% to 10% range around the estimate. However, one can achieve even greater confidence by increasing the sample size. Surely, it is clear that a representative sample of even 1,000 points will be much less costly to monitor than attempting to measure the response from all connected devices.

One-way vs. Two-way Program Free Riders

Some people argue that since the utility is paying an incentive to achieve a demand response, they should not pay people whose devices for some reason or another failed to receive the signal or precipitate the load control. I argue that utilities should not worry much about these "free riders." An analogy might help explain. Shoplifting is stealing and it is illegal. People should not shoplift. Unfortunately, the cost of preventing shoplifting is higher than the losses that attend shoplifting by several orders of magnitude. Consequently, consumers pay more for the products they buy than they should in a world with no shoplifting but far less than they would pay in a world that incurred the costs to eliminate the crime. Utilities sponsor demand response programs for the aggregate demand response they receive during control events. The cost of being certain all connected devices respond to each control signal is much higher than the cost associated with paying some participants incentive payments they do not "earn." Utilities should focus on deploying mass-market demand response programs that provide the most aggregate demand response per dollar spent.

One-way vs. Two-way AMI Considerations

The case for one-way demand response networks is even stronger where there is an advanced metering infrastructure (AMI) in place or in the process of rolling out. Where there is AMI, the individual demand response is observable in the meter readings—effectively providing the two-way communications via an alternative route. This does not mean AMI is a good idea because it enables ubiquitous verification of individual demand response. AMI needs to be justified on other grounds because ubiquitous verification is unnecessary and not cost-effective for networks of mass-market load control devices. However, if a utility already has an AMI or AMR infrastructure then one-way DR networks will in many ways work like two-way DR networks —they already have the "back haul." Figure 2 below illustrates.

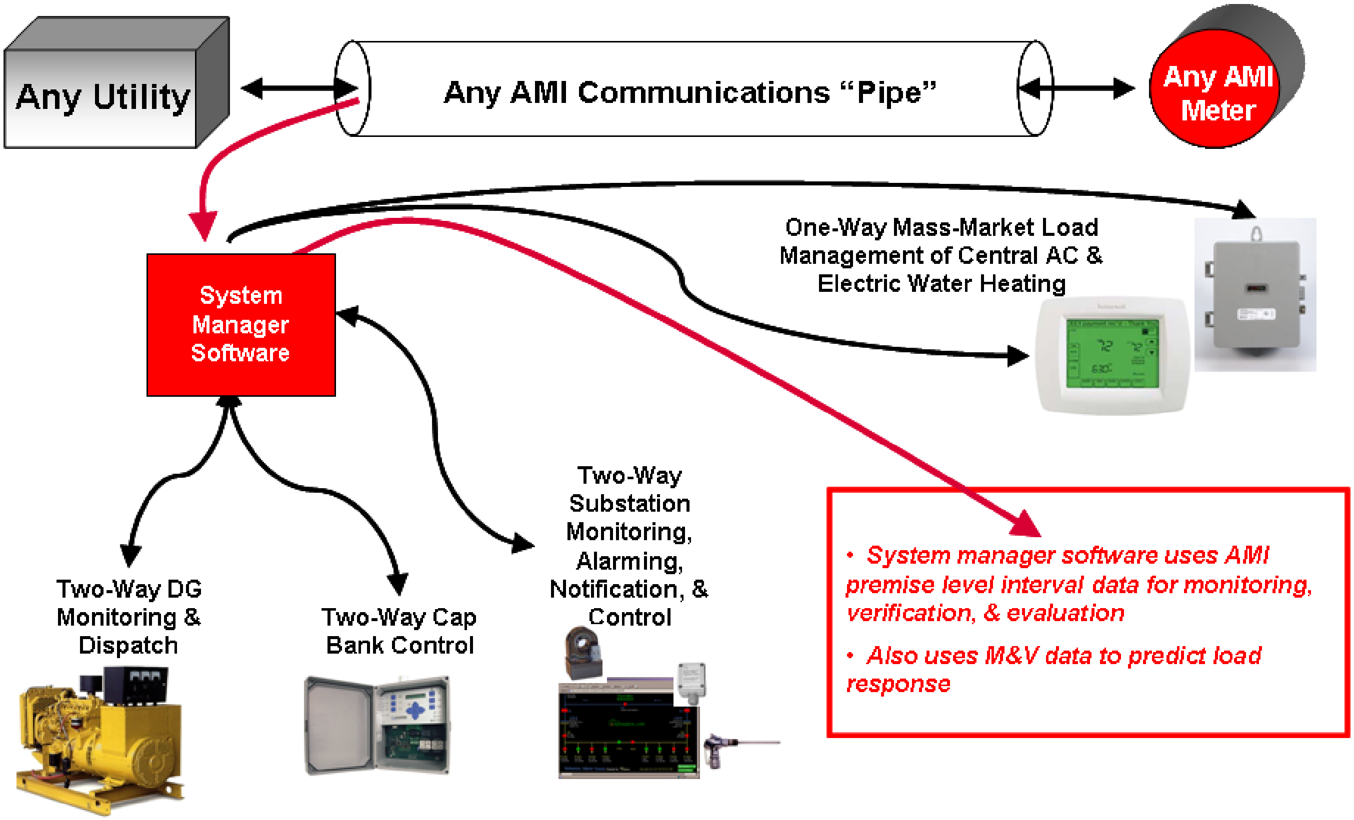

Figure 2 - One-way DR Networks with AMI

Conclusions

If you have a legacy one-way load management system, you can enhance its value and expand participation by using creative program design and by exploiting the near-ubiquity of the Internet, the individual addressability of devices, and existing but underused features of system management software.

If you do not have existing mass-market load management programs and you have a need for peak demand relief, you may not want to wait for a fully "tricked-out" smart grid. You can economically deploy one-way systems today that can provide much of the same functionality as two-way systems may someday provide.

Today peak period relief is only one-quarter to one-half the cost of avoided generation and is even more valuable when you include the benefits of avoided transmission, distribution, and ancillary services. Through program design, customers can gain new choices and a greater feeling of control without significantly discomforting or inconveniencing them.

Two-way DR networks fully integrated with a modern smart grid, communicating seamlessly and using open protocols from generation stations through to home area networks may well characterize the electricity system of the future but we will not get there all at once. In the meantime, using what we already have more intelligently seems like a good thing to do.

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