METER SCOPING STUDY

California Energy Commission

Prepared By:
Levy Associates
2805 Huntington Road
Sacramento, California

Roger Levy
Author

Prepared For:
Laurie ten Hope

John Wilson
Project Manager

Terry Surles
Deputy Director
Technology Systems Division

Steve Larson
Executive Director

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Acknowledgements

The author wishes to acknowledge the contributions of Plexus Research, Inc. for their technical assistance regarding some of the metering technology, capability and pricing information.

The author also wishes to thank Ron Hofmann for his extensive contribution and assistance in editing the final report.

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Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program managed by the California Energy Commission (Commission), annually awards research funds to conduct the most promising public interest energy research by partnering with Research, Development, and Demonstration (RD&D) organizations, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following six RD&D program areas:

- Buildings End-Use Energy Efficiency
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy
- Environmentally-Preferred Advanced Generation
- Energy-Related Environmental Research
- Strategic Energy Research
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- In 1998, the Commission awarded approximately $17 million to 39 separate transition RD&D projects covering the five PIER subject areas. These projects were selected to preserve the benefits of the most promising ongoing public interest RD&D efforts conducted by investor-owned utilities prior to the onset of electricity restructuring.
- What follows is the final report for the Meter Scoping Study.
- For more information on the PIER Program, please visit the Commission's Web site at http://www.energy.ca.gov/research/index.html or contact the Commission's Publications Unit at 916-654-5200.
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Abstract

Advanced meters with communication are necessary to facilitate California Energy Commission (Commission) pricing and program objectives and to support improved customer energy investment and operating decisions. Market-based rates and advanced metering together provide customers with demand-response capability that can link wholesale and retail markets in ways that mitigate system reliability and price volatility. In addition to the demand-side benefit, advanced metering provides general business and operating advantages that on their own appear to cost justify investment and implementation.

Not withstanding this experience, utilities and regulators often cite cost, technology or other factors as barriers to implementation.

This report presents a summary of metering technology and cost information from past studies in an attempt to identify key barriers to more widespread implementation.

The author concludes that institutional and a narrowly defined cost/benefit methodology, not technology or cost, are the principle barriers to future implementation.

Executive Summary

With few exceptions, most utility tariffs and metering systems are designed only to collect customer usage data to support a monthly bill. Existing utility systems provide functional capabilities little changed from those introduced over sixty years ago. As a result, most consumers are billed under rates that generally have no relationship to the actual cost of energy and receive only aggregated usage information sometimes months after the fact.

Advanced metering provides the capability to measure and record energy usage at intervals of one hour or less. Communication links provide capability to automate utility metering functions and to integrate a variety of business functions, often at substantial cost savings. These same advanced metering systems can provide customers with capability to interrogate and read meter information on demand and to receive up-to-date energy pricing. More significantly, advanced metering with integrated communications enables an entire portfolio of new demand-response options that include dispatchable rates, demand bidding, and real-time tariffs deemed essential to California's energy future.

Although the combined value of business system improvements and demand-response options appear to make a compelling economic case for advanced metering, implementation continues to be the exception and not the rule. The role of advanced metering to the utility and customer is still not well understood. Funding and implementation decisions perpetuate the view that systems are expensive and not yet an essential component of electric service.

This report reviewed prior literature and recent utility experience to examine three fundamental issues, specifically:

1. Identify the most significant technical, economic, operational and political barriers impeding or restricting implementation of advanced metering;
2. Identify how these issues may impact California Energy Commission (Commission) policy and programming objectives, and;
3. Identify potential research and other developmental activities to mitigate the barriers.

Implementation evidence does not support the industry perception that technology and cost are barriers to implementation. Instead, the most significant barrier appears to be the inability of existing cost effectiveness methodologies to properly capture and account for metering impacts. Cost effectiveness is generally assessed using methodologies developed to evaluate demand responsive programs. These models do not capture many of the business system, customer demand-side, and industry value-chain benefit streams. Methodologies also ignore the financial impacts of alternative financing.

Research recommendations were developed to emphasize a narrow range of activities to improve both the quality of information and methodologies for assessing metering costs and benefits. This emphasis is consistent with the underlying conclusion that cost effectiveness and not hardware or technology, are the primary barriers to implementation.

1.0 Introduction

- *Is advanced metering necessary to support effective demand management programs?*
- *Are there technical or market factors that limit the implementation of advanced metering?*
- *Is an advanced meter and communication link to the customer an integral element of all future electric services?*
- *Do customers use and respond to more detailed and more timely energy information?*

The role that advanced metering provides within the electric power industry has been under continuous scrutiny and investigation for over 20 years. While the questions, like those above, may change from moment-to-moment, there is a set of foundation issues that are common to each evaluation. Metering technology, communications and standards are several of the foundation issues, however none of these are current barriers to implementation. Cost effectiveness alone is the singular, most important issue that drives decisions by utilities and regulators alike. However, to determine the costs and benefits of metering, decision makers must clearly understand that advanced meters play a much different role in the electric service business than the technology they replace. This role is not well understood. As a result, funding and implementation decisions perpetuate the view that meters are expensive and not yet an essential component of electric service. Some of the information in this report attempts to address this point of view.

Within the context of this report, advanced metering is assumed to be any device installed on a customer facility that includes: (1) the capability to measure and record energy usage at intervals of one hour or less, and (2) an integrated communication link that provides either the utility service provider or customer with capability to interrogate and read meter information on demand. Both features in combination are necessary to support curtailable, demand bidding and real-time tariff options deemed essential to California's energy future. The data recording and communication features are also necessary to support customer education, facility operations and energy investment decisions. Specific technologies are considered important only to the extent that they materially affect either one or both capabilities.

1.1 Purpose of this Report

There are three fundamental assumptions that underscore the entire basis for this report: (1) advanced meters are necessary to facilitate California Energy Commission (Commission) pricing and program objectives, (2) advanced metering systems provide an essential source of information to support customer education and electric system operation, and (3) cost, technology or other factors create barriers that impede implementation. This report examines the current status of advanced metering in the electric utility industry. Specifically, this report attempts to identify:

- The most significant technical, economic, operational and political issues that currently impede or restrict the implementation of advanced metering.
- How these issues may impact the implementation of Commission policy and programming objectives, and
- Potential research and other developmental activities to mitigate key implementation barriers.

This report is organized into five sections. Section 1.0 provides background and historical information that describe the basic evolution of metering from a single function ‘industry cash register’ to a data portal. The next three sections address substantive information regarding meter hardware, the customer interface and basic meter system economics. The most critical issues are highlighted in the shaded box at the start of each section. Each section then presents descriptive information related to the core of the issues. Technical and engineering details, while important, were not considered relevant to this review. More specific discussion and comment on the issues, barriers and their implications on Commission research and policy are deferred to the last section. Section 5.0 presents summary observations and recommendations.

1.2 Background

With few exceptions, utility metering systems were designed and are still operated today to support production of a monthly billing statement. This statement is the only regular source of energy price and usage information available to end-use customers. Unfortunately, current billing data suffers from major deficiencies:

1. Information from these systems is usually limited to a single kWh usage value that is aggregated over whatever number of days may be included in the current billing cycle,
2. The information is only available well after the energy has been consumed, and
3. Price data is usually presented as an average value over a fixed rating period, where both the price and rating period may have little relation to actual system conditions.

Without current usage and energy price information, customers cannot make informed short-term operational decisions. Without a history of energy usage and price information, customers don’t have a foundation for making the long-term investment and technology decisions that balance the value of their service against their cost of service.

Advanced metering has been a subject of reasonably intense utility industry research and development for over twenty years. Hundreds of field trials, engineering research studies, workshops, regulatory hearings, and private development efforts and hundreds of millions of dollars in product evaluation have subjected advanced metering to a very broad and thorough review. Consequently, this report does not attempt to present new, original research. Instead, this report brings together some of the key observations and findings from recent regulatory and private research studies that have been conducted over the last few years.

Communication and digital data collection technologies provide utilities with capabilities to automate and significantly improve billing, customer service and operating practices. Using a digitized data stream to automate and electronically link operating functions within a utility and between the utility and their suppliers and customers creates opportunities for new rate options and new services that not only reduce costs on both sides of the meter but also create opportunities for new revenues and profits.

1.3 The Existing Metering Environment - A Brief History [1]

When the first electric utility companies organized in the late 1800's and early 1900's, they had to compete for market share against gas, kerosene, coal, wood, and other well-established fuels. Because of competition, electric companies offered a variety of innovative rate and service options. Preferential rates, time-of-use rates, and negotiated contracts with selected businesses were common methods for attracting customers and building load. Even more popular were special rates for general lighting, sign lighting, ceiling fans, flat irons, electric pianos, and other end-uses. All of these rates provided customers with two features essential to a competitive marketing effort – choice and clear pricing information. Rates differentiated by end-use, provided customers with distinct choices to incrementally select how they used electric service, while end-use pricing gave customers the information necessary to balance their level of service with service cost.

What is unique about these early rate options is that none employed metering. All of these innovative service options were based on fixed rates by end user regardless of usage level. For utility companies, meters and meter readers were expensive. Customers were indifferent. Why worry about metering when, year after year, economies-of-scale continued to provide more service at lower cost.

Eventually, successful marketing and reduced costs of service produced two basic changes in the industry that led to the widespread implementation of regulation and metering. First, successful marketing and advantageous economics allowed a few hundred electric companies (investor owned utilities) to dominate their markets and eliminate most competitors. This consolidation and centralization of power in turn led to the onset of regulation. Regulatory oversight formalized utility operations by developing rules, procedures, and principles to govern rate design, billing, and other customer services. Concurrently, the ever-decreasing cost of service in combination with increasingly dominant market positions reduced the need for electric companies to offer competitive rate options.

What evolved was a move to simplified usage-based rates that required meters and meter reading. The need for metering was initially driven by the billing function. The earliest meters employed electro-mechanical technology to spin dials that continuously updated the customer's cumulative usage. Subtracting a current reading from a prior reading allowed utilities to compute kWh usage during the intervening period. For many utilities, it wasn't possible to read all of the meters at the same time or on the same day. Meter reading posed a

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1. Adapted from "Metering in a Competitive Electric Utility Industry: Another Step toward Electronic Commerce", Newsletter of the Utility Restructuring and Competition Consortium, International City/County Management Association, Volume2, Number 3/4, summer /Fall 1998.

logistical problem – how can you read hundreds or thousands of devices all at the same time, that are continuously recording customer usage, to put out a bill at the end of each month? You can't. Consequently, to balance their workload and hiring, most utilities divided the meter reading task evenly across the working days in a month. Spreading the workload simplified hiring, workload management, and the flow of billing data. For existing metering systems there are two important factors to remember:

1. Existing metering systems were designed around a technology that was never intended to support anything other than a single function – meter reading;
2. Existing meter reading practices were designed to address a logistical problem that can now be easily addressed by any number of communication systems.

Utility metering and information practices today haven't changed much in the last 50 to 60 years. Current practices evolved out of early business, regulatory and technical conditions relevant to a vertically integrated industry with declining costs. Meters were necessary only to support a single function – to periodically measure usage for computing a monthly bill. Meters were utility property, under utility control, with little or no value to the customer. Meters became the highly protected '*cash register*' to the industry. This perspective still dominates the electric utility industry today.

There is another perspective that better reflects the capabilities of modern metering technology and the information product that those meters produce. Within this new perspective, meters are viewed as an information gateway that sits between the customer and utility service provider. Figure 1 schematically represents the meter gateway and the many utility and customer functions potentially supported. Historically, meter data flowed only to the utility and then only to support a very narrow billing function. For most utilities, although billing is a part of system operations, data from billing applications rarely is integrated into forecasting, rate design or evaluation functions. Instead, separate metering samples (load research) are maintained to support these functions. The same situation exists for outage management, program evaluation and other functions – separate systems, separate data and a general lack of integration at a company level.

Today, metering with communication capabilities do not exist in isolation from other utility business and management systems. Meters at the customer site can provide utilities with data that ultimately support all planning, operating and evaluation functions. In its most basic form, the same metered data used to generate customer billing statements can also be aggregated and combined with other information to support almost all internal utility operating and planning functions. Forecasting, rate design, fuel procurement and system dispatch all depend upon metered usage data. How data is accessed and provided from metering systems can also either hinder or enhance the exchange of data and cost of doing business between the utilities, their suppliers and their customers. Numerous case studies document these applications and the substantial benefits produced.

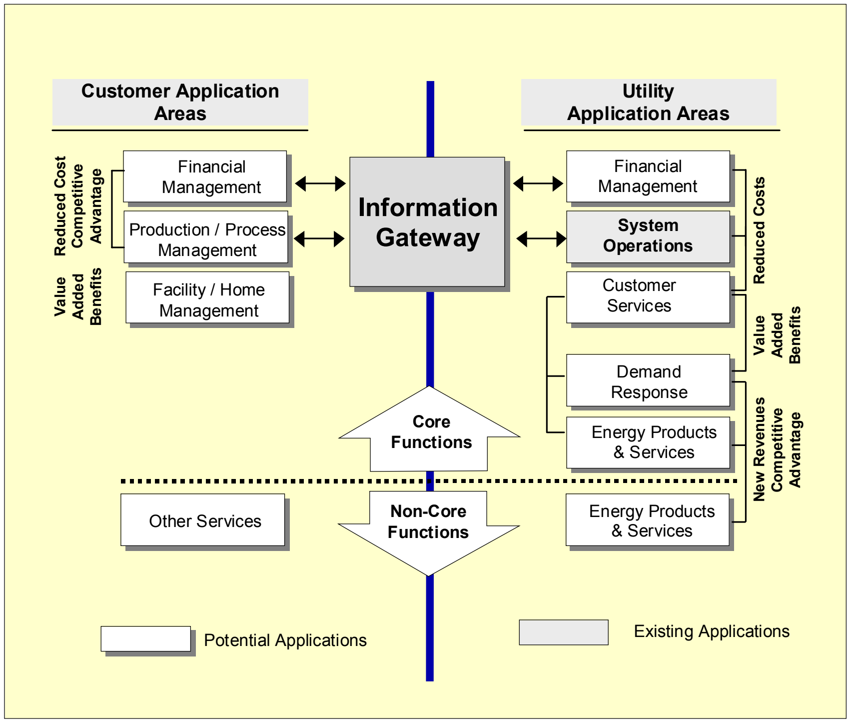

Figure1. Advanced Metering as an Information Gateway

What often escapes consideration in both utility and regulatory reviews is the role that this same meter information plays in supporting highly valued customer applications. Isolated implementations and field trials by utilities have repeatedly demonstrated that customers of all types, from the largest commercial / industrial multi-site companies to the average residential customer find valuable applications for meter data. For example [2], in a first-of-its kind application that began in the late 1980's, Georgia Power Company provided selected commercial and industrial customers with direct computerized access to the meter data at each of their sites. Customers used the detailed information to track, audit and forecast their utility bills, monitor facility operations, spot operational problems, plan production schedules, balance production with cost differences in different jurisdictions, automate accounting functions, and provide a common foundation for demand-side investments. In several companies, detailed meter data became an integral input to their daily operating plans. It was this type of customer response that encouraged Georgia Power to develop the first successful real-time pricing and electronic billing applications. In essence, Georgia Power converted the meter into a bi-directional information gateway.

2. "Opportunities in Advanced Metering and Distribution Automation", EPRI report RP2568, October 1991, prepared by Levy Associates.

Residential customers have reported similar types of benefits. Field trials by AT&T and TranstexT cited later in this document identify specific results. More recently, Puget Power has introduced system wide metering that provides residential and commercial/industrial customers alike with regular energy usage and other information. Substantial conservation and demand reductions reported in the first few months, have been attributed to customer actions based solely on this new information. [3]

Consequently, meters should be viewed as part of a much larger information system and a critical component in the utility-customer business management process. Because of their position at the head-end of the business process, meters and the data they collect, directly influence costs in all remaining utility operations.

For example, to support metering and billing functions, utilities implemented computerized customer information systems (CIS). These systems were designed to support billing and basic customer record keeping. However, due to limitations in early computer system capabilities, almost all CIS designs still employ a monolithic, rather than a modular design that groups all customers into a single large scale system. This design approach worked reasonably well when most customer rates were based solely on simple billing parameters. However, beginning in the late 1970's CIS entered a stage of almost continuous modification to accommodate much more complex time varying, demand, and other incentive type rates. The design and complexity of these rate options made CIS both difficult and costly to modify. In many cases, preferred rate designs had to be compromised and program implementation delayed due to the limitations of the CIS. If the CIS cannot be modified to perform the necessary calculations, the rate can't be supported. To complement this problem, innovative rates and demand-side programs were frequently dismissed as not cost effective because the cost to replace the CIS was so expensive. CIS and especially their billing system components continue to act as bottlenecks to the implementation of advanced metering technologies as well as innovative rates and demand-management programs.

A prime example of the CIS bottleneck situation is exemplified by the settlement cycle developed to support payments between the utility distribution companies (UDC's), the California Power Exchange (PX) and California Independent System Operator (ISO) as part of the original California restructuring effort. Because of combined limitations in their electromechanical metering systems and CIS, UDC's pushed for a settlement process designed around their existing 30-day meter reading cycles rather than the more flexible electronic capabilities being used and promoted by energy service providers (ESP's). Electronic metering and short settlement cycles were preferred by alternate providers to minimize operating cost, receivable float and working capital requirements. Although electronic settlement cycles of as little at 3-5 days were considered in initial proposals, limitations in UDC metering systems ultimately dictated the UDC proposed and approved 67-day settlement process.

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3. "New technology monitors homes energy use", The Mercury News, March 8, 2001 - Kristi Heim and Jon Fortt
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The evolution of information systems into technological bottlenecks is not unique to the electric utility industry. For example, after deregulation of the telephone industry, Pacific Bell discovered that their billing system could not support the new technologies, services and rate options that they needed to provide to their customers. "So severe was the problem that Pacific Bell couldn't bring new services to market – because it couldn't make the system send out the bill." [4]

This situation poses an inherent dilemma. How do you value the functions and information available from modern metering systems and then draw meaningful comparisons against embedded, less functional systems?

2.0 Metering and Communication Systems (Hardware and Systems Design)

Issues: Technology Availability

- Metering and communication technologies are not readily available or capable of supporting the most critical utility applications.
- Standards need to be developed to guarantee implementation flexibility and system interoperability.

Metering and communication systems collectively include a broad range of complex technologies that are typically addressed at two different levels: (1) detailed engineering and performance specifications, and (2) basic functional and operating capabilities. Engineering and performance specifications are appropriate to distinguish between vendors or service providers once the implementation decision is most certain. Functional and operating capabilities are generally assessed as building blocks in determining whether implementation is even a practical or an economically viable alternative. The discussion that follows focuses on functional and operational issues.

Market studies by Electric Power Research Institute (EPRI) and other research organizations over the last few years report that as much as 99 percent of all utility meters are designed and are only capable of providing a single monthly usage value. [5] It is interesting to note that the dominance of 'limited capability' metering has changed little during the last ten years, when during the same time period vendors have introduced an extraordinary of number of functionally improved metering systems and unit costs substantially declined. This situation implies that the overwhelming dominance of existing, limited capability metering is probably due to a combination of regulatory and organizational factors, rather than cost or availability. There is no compelling vision to encourage investment.

There are two factors that limit the capability of existing electro-mechanical and other systems: (1) they use analog or even digital 'accumulating registers' that fail to capture or

4. Technical Brief: Strategic Outsourcing, A Telecommunications Example of Improved Bill Processing and Enhanced Customer Services, Prepared by Levy Associates for EPRI, July 1996.
5. Much of the information on hardware systems was taken directly from "A white paper on Direct Access Metering & Data Communication Requirements", Prepared by Plexus Research, Inc., for the National Association of Regulatory Utility Commissioners, March 31, 1998.

retain time-varying customer usage data and (2) they are not equipped with communication links that allow the meter data to be accessed remotely as needed.

Communication capability ultimately determines what functions metering systems can or cannot support. Without a communication link, meter readers or other reading devices must come into contact with or physically pass by the customer site to read the meter and download usage data. Lack of remote communication capability imposes a new logistical constraint that acts to restrict access to meter data. This in turn directly restricts customer tariff and other applications to those that work only with monthly or less periodic data. Logistically driven fixed reading schedules and on-site reading devices also limit the volume of data that can be collected, how often that data can be accessed, and when it can be used. Aggregating interval data in registers at the meter rather than in the data translation or billing system, means that detailed interval usage data is not available to either the customer or utility for analysis, operational or administrative purposes. Aggregating data in physical registers at the meter rather than with software at the utility further restricts access to meter data. This directly restricts customer tariff and demand responsiveness options.

Until recently, the cost variation between hours or time periods of a typical day were not judged significant enough to warrant more than seasonal time-of-use rates. Traditional time-of-use (TOU) rates use rating periods defined as blocks of hours and prices within each block that change only seasonally, not daily, irrespective of actual changes in the cost of energy on any specific day. In contrast, real time price (RTP) signals vary hour-by-hour in concert with actual wholesale market prices for energy. Price variation, properly communicated to the customer, encourages customers to use energy more efficiently – using more at lower prices and less at higher prices. Using these same price signals to compute their bills means that customers pay for what they use, when they use it. Like the end-use rates offered at the turn of the century, RTP rates provide customers with a clear link between the services they use and the price they pay.

However, to support a tariff based on real-time pricing requires a minimum set of capabilities: (1) a meter capable of capturing interval data and (2) a communication link to the meter to retrieve data for both the billing and customer information function. Metering systems and their data collection capabilities can be naturally divided into three simplified categories based on their communication capabilities (Table 1). Manual and drive-by meter reading systems, which are the dominant systems in place today, were designed to support conventional rates that only require a single kWh usage value over every 28-32 day monthly billing cycle. Drive-by meter reading systems, sometimes also referred to as automated remote or drive-by systems, basically just improve the efficiency of conventional manual systems by speeding up the collection of usage data. Utilities often employ these systems because they significantly improve the productivity of each meter reader, which in turn generates labor savings (fewer meter readers).

Interestingly, on-site economic and hardware (meter, communication module and installation) retrofit requirements for drive-by systems are almost identical to those for more capable automated/network-based automatic meter reading (AMR) systems. The principal difference is in the cost of the communications network for actually retrieving the data. For drive-by systems, the network is the fleet of trucks, drivers (meter readers), and fleet support systems.

For the automated/network-based systems the network is either: (1) the hardware and software to create a new private communication network, or (2) the licensing arrangements, hardware, and software to gain access to an existing public communication systems. Both private and public networks generally require similar head-end communication interface equipment and more capable data processing capability at the utility.

Table 1. Simplified Classification of Metering Systems

Type of Meter System	System Features	Support for Real Time or Time Varying Rates
Conventional Manual or Electronic Keypad Systems	• Requires meter reader to cover a fixed route. • Meter values key-entered or electronically downloaded via port to hand-held recorder.	• Typically limited to a single kWh (kilowatt-hour) usage value each billing cycle. • Cannot economically or logistically support the collection of time varying kW interval data • Data only available once each billing cycle or with special read.
Drive-by Meter Reading System	• Requires meter reader to cover a fixed route. • Van-based drive-by or hand-held systems that use low power radio to transmit meter readings over short distances.	• Can support the collection of multiple kWh register values used in standard TOU rates. • Communication methods cannot economically or logistically support the collection of time varying kW interval data. • Data only available once each billing cycle or with special read.
Automated/Network Meter Reading Systems (Public or Private Communication Networks)	• Meters connected to a data repository by telephone, PCS, paging, satellite, fiber, or other communication technology. • Stored meter readings can be collected on a fixed schedule or on demand.	• Preferred methodology for collecting interval data. • Full compliment of interval and other meter data generally available on demand. • Accessibility varies by technology, may limit some 'inbound' only systems.

Due to the similarities between drive-by and automated/network systems, it would appear that the economic analysis to support system acquisition decisions should focus almost exclusively on the tradeoffs between differences in network related costs versus differences in the value of data provided by each system. While remote metering systems provide incremental improvements in meter reading efficiency, they provide no other significant utility system or customer service benefits (Table 2). On the other hand, automated / network based systems provide efficiency improvements that substantially exceed those provided by remote systems. In addition, automated / network systems provide extensive utility system operating benefits and support a wide range of customer rate and service options.

Metering System	Metering Functions							Operating and Strategic Benefits				
	Data Recording			Monitoring and Control		Customer Service						
	kWh Usage	kW Intervals	kW Max	Tamper Detection	Outage Monitoring	Dispatch Rates	Load Profiles	Reduced Costs	Improved Revenues	Efficient Operations	Added Customer Services	Rate/Price Flexibility
Manual	●											
Drive-by Remote	●	○	○					○				
Automated or Fixed Network	●	●	●	●	●	●	●	●	●	●	●	●

Blank – no benefit ○ some benefit ● greatest benefit

Table 2. Meter System Function – Benefit Comparison[6]

2.1 Market Factors - Meter Technology and AMR[7]

"The technology for acquiring hourly meter data from large commercial and industrial customers already exists from more than a dozen suppliers, is easily cost justified, and is often already in place or readily upgraded." [7] Collectively, suppliers support almost all available fixed network or stand-alone communication methods including standard dedicated / shared telephone, cellular, satellite, powerline carrier and local area network-based (LAN) Internet. Metering technology for the remaining small commercial / industrial and residential customers, although available from many suppliers has traditionally been more difficult to cost justify. Cost benefit methodologies make purchasing and operating assumptions that make it difficult to justify implementation given the lower energy usage levels of this group relative to large users.

Even given less favorable economics, more than a third of new residential revenue meters sold in 1997 included some kind of electronic communication or electronic register modules built-in at the factory. These electromechanical meters with built-in electronic modules sold for about $60 to $85 each, depending on volume. Generally, vendors price new electronic meters to compete with the electromechanical meters with built-in electronic communication modules. Integrating the communications with the electronics in the meter reduces the cost of the communications module enough to offset the fact that the bare electronic meter costs more than a bare electromechanical meter. During the first six months of 1998, electronic meters

6. Remote access drive-by or van-based systems are not capable of collecting interval data except on an exception basis. Consequently, these systems cannot easily support time-of-use or real-time pricing rates.
7. Much of the information on hardware systems was taken directly from "A white paper on Direct Access Metering & Data Communication Requirements", Prepared by Plexus Research, Inc., for the National Association of Regulatory Utility Commissioners, March 31, 1998.

with built-in communication modules cost less than $100. By mid-year 2000, vendor offerings were being quoted at $60 to $90. By early 2002, vendor quotes were even lower.

"Four firms supply more than 99% of residential and small commercial electric revenue meters in the U.S. The four firms manufacture residential and commercial electro-mechanical meters, which are substantially interchangeable, due to well-established standards developed over many decades of metering practice.

- ABB Power T&D, Raleigh, NC (formerly Westinghouse meters)
- General Electric Company, Somersworth, NH
- Siemens (Landis & Gyr, Lafayette, IN formerly Duncan meters)
- Schlumberger Industries, Norcross, GA (formerly Sangamo meters, acquired CellNet in 1990)

Although each of these firms have also ventured into various automatic remote metering technologies, the most prominent and successful companies, surprisingly, are not the meter manufacturers. Two companies, Itron and Schlumberger dominate the metering market, Itron with its drive-by systems and Schlumberger with its fixed network Cellnet systems. Technically, both companies specialize in system integration, providing communication and software systems that integrate with contracted or customer designed hardware from other industry providers. These firms work closely with meter manufacturers to provide utilities with specialized meter configurations with factory installed communication modules.

Even with this narrow domination of the meter market, there are more than thirty companies that offer advanced metering systems capable of remote residential and/or commercial metering options. [5] Continued innovations and downward price pressure generally indicate both a willingness by manufacturers and others to invest in meter development as well as a belief that the market offers untapped potential.

2.2 Regulated versus Competitive Metering Environments

Each metering system has its technical strengths and weaknesses. Each has physical and operating environments in which it flourishes or fails. In general, no single metering or communication technology is ideal for all needs under all circumstances. Even with all of the advances in metering and communication technologies, most utilities continue to find that combinations of various technologies are needed to address all customer and system needs. This is true regardless of the size of the utility (number of customers) or whether the utility operates in a regulated (bundled) or competitive (unbundled) metering environment.

The prevailing position within the regulated utility industry is that metering and communication costs will be more economically viable if they remain the exclusive franchise of the incumbent utility. Many currently available drive-by and network systems were designed to support utilities operating in a regulated environment. Their designs make an underlying assumption that each utility will have rights to a specific geographic franchise - an area in which it would be the exclusive provider of all meters and metering services. This ‘exclusive franchise assumption’ provides a predictable communications environment and an implementation volume that can often capture economies of scale not available to a divided market. With an exclusive service arrangement, the number of customers and the density of customers per square mile or per transformer can be easily determined. These facts allow vendors to design systems that capitalize on existing utility distribution and other communication infrastructure to lower the cost of metering services. The available communications capacity of other utility high speed, wide area telecommunications assets could also be used to support higher levels of the AMR system hierarchy. Finally, a regulated environment, with a single meter provider is often preferred by vendors because it allows them to more narrowly focus their sales effort.

Conversely, competitive or unbundled environments with numerous service providers can be expected to encourage a more diversified mix of metering and communication systems than in a single provider system. Competitive environments may also be subject to higher unit costs due to lower installation volumes, lower densities over which to amortize fixed communication equipment costs and higher customer switching/turnover rates. With fewer meter units per sale, vendor overheads and selling expense is also higher.

However, it is not clear nor does industry data necessarily support the conclusion that regulated environments produce lower cost systems or lower per customer unit costs. Competitive providers may capture equal or greater offsetting benefits due to lower administrative and overhead costs. In some regulated utilities, overheads can add 80 to 100 percent to the hardware, installation and other system costs. Competitive providers may also capture substantial additional benefits from outsourcing metering and communication functions to specialty providers that have both the expertise and collective volumes to offset any ‘scale’ advantage accruing to a conventional regulated, exclusive franchise.

The outsourcing option also potentially allows competitive providers access to all of the same metering and system options available to single source, bundled providers. Consequently, there are no specific types of metering systems that are inherently better suited to bundled versus unbundled environments. The appropriate type of equipment will be determined, in either case, by the volume of meters to be installed, the density of installations within a geographic area, the functional requirements of both the customer and service provider and finally, the viability of the competitive market. By example, within a few months after opening, the restructured California market boasted numerous competitive meter service providers (MSP’s) and meter data management agents (MDMA’s). Unfortunately, price caps, approved utility meter replacement credits, and other procedural barriers eventually forced most of these providers out of business.

It is also important to note that the same outsourcing benefits typically associated with competitive providers are also available to regulated utilities. Outsourcing is not an option exclusively limited to competitive providers, however, regulated utilities have generally been reluctant to give up control over what they consider a traditional and critical financial function. Regardless, there are several innovative regulated utilities that provide examples where outsourcing and various hybrid outsourcing arrangements have generated substantial cost and operating advantages. For example, in the early 1990’s Kansas City Power and Light (KCP&L) pursued an innovative outsourcing contract that they characterized as a shared opportunity arrangement. Their contract provided a reduced capital investment requirement, an equity stake in an outsourced metering system and performance guarantees designed to meet regulatory cost benefit requirements. [8] More recently, Puget Power implemented a fully outsourced system that was cost justified solely on the basis of internal operating cost savings. According to Puget, their combined gas and electric system wide metering project will produce $27.23 of annual net benefits per meter.[9]

2.3 Network Metering – System Options [7]

Communication-base (non drive-by) or networked automated metering systems (AMR) are usually characterized by the communication technology (wireless radio, telephone, powerline, etc.) used on the ‘first hop’ from the meter to somewhere higher in a hierarchical communications system. A variety of communication technologies may be used further up in the system hierarchy beyond the ‘first hop’. For example, a metering system which uses unlicensed, short-range radio to transmit data from the meter at the consumer’s premises to a data collector at the transformer or another distant point in a network (the ‘first hop’) would be classified as an unlicensed radio AMR system. The metering system may employ mixtures of fiber, microwave or telephone at the higher levels within the system to move data form the collector to the utility billing computers. Economics, availability, system reliability needs and utility preferences govern the eventual choice.

Typically 75% of the cost of a communication-based or network system lies in the sensing and communication devices installed in or near the meter at the customer’s premises (installation cost is included in this 75%). The remaining 25% of system cost lies in the intervening communications and in the ‘head end’ computer systems which control the system and gather and forward the information to billing computers. As a result, utilities generally prefer systems that minimize the cost of the meter module and installation.

In addition to the communication technology, communication-based or network systems are differentiated by a design feature that produces two inherently different system options. Generally, these systems can be placed in one of two categories: (1) smart meters with transparent networks or (2) dumb meters with intelligent networks.

The ‘dumb’ meter is designed with a minimum of local intelligence. It simply transmits pulse counts for a pre-defined time period, usually 5-60 minutes, over an ‘intelligent’ network. The ‘intelligent network’ is been designed with capability to perform all data manipulation, accumulation and time tagging to produce an accurate meter reading. Systems with dumb meters attempt to minimize system costs by reducing the complexity of the module installed in the meter. The complexity is moved upstream into the network, where fewer processors can serve a large number of meter points within their communications range. Data management is also more economically performed higher up in the communications hierarchy. As a result of their design and dependence on the network, these systems often

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8. Technical Brief: Automatic Meter Reading and Distribution Automation: A Case Study Example of an Innovative Business Model, Prepared by Levy Associates for EPRI, August 1996.

9. Private Communication with P.J.Gullekson, Vice President of Customer Services, Puget Power, November 2000.

require a customized, proprietary private network that may be dedicated only to utility related data transmissions. The dumb meter, smart network is presently the lowest cost way to deploy AMR in areas of high customer density.

The dumb meter / smart network approach has the notable disadvantage that a single point failure in the smart network can cause substantial disruption and data loss. However, most systems are designed to anticipate and compensate for random failures by either building in redundancy or overlapping coverage in the network devices.

Smart meter / transparent network systems have the same potential liability. In both systems, data remain available in the meters for a predefined time period. The difference is that the dumb meter usually only retains a total cumulative kWh reading, while the smart meters may retain load profiles, time-of-use values and other detailed data elements.

Because the intelligence and cost with dumb meter systems has been shifted into the network, they usually require a minimum density of metering points per square mile before they become economical. For widely dispersed metering points, typical in some suburban and rural areas, the cost of a dedicated wireless network is prohibitive. Diluting the number of meters addressed by each 'smart node' in a dumb meter / smart network system can undermine the otherwise favorable economics of these systems. It is this potential dilution in the economics that forms one of the key arguments against unbundling. However, this argument has never been supported by a complete cost and benefit showing.

The smart meter/transparent network systems build ample logic and data manipulation into the meter, in effect sending forward fully formed messages about consumer consumption. These meters are indifferent to how data is transported as long as it gets from the meter to the utility billing computer. No data manipulation is required in the wide area data transport network. Telephone, paging, satellite or other media may be used. Since these systems are not necessarily dependent upon specific networks, they can often be deployed economically at much lower densities than the dumb meter / smart network alternative. Because of their design, smart meter / transparent network systems usually can operate over existing public communication networks. This option may make smart meter systems easier to implement, although they then become subject to contracting uncertainties and competitive applications from other providers needing communication capacity.

This ability to 'parachute in' metering points, oblivious to any need for a dedicated fixed network, provides great freedom for the smart meter approach. In addition, the self-contained nature of the smart meter may also allow it to begin communicating immediately over an existing two-way paging network or telephone lines.

While there are distinct differences between the dumb meter and smart meter approaches, there is no absolute technical or economic basis for suggesting that one system is better than the other. Each system has its own unique costs, benefits and operating features. Irrespective of costs, at different times each system may be considered the best technological and economical choice for a particular application or customer. In fact, there are situations where both systems may coexist side-by-side. Reducing the cost of one system may not necessarily create a technological or operating advantage over the other.

2.4 Meter Standards

Hardware, software, communication and other standards are usually developed for one of three possible reasons: (1) assure the public safety, (2) enforce the quality and integrity of the product, and (3) promote commerce through compatible interfaces.

Meter standards have developed in three rather distinct phases. The first phase, which began prior to 1980, saw the development of basic meter hardware (socket and construction) and performance standards (measurement methods and tolerances). These standards evolved from years of interaction between utilities and manufacturers. Utilities, seeking to eliminate the risk involved in dealing with only one supplier, over time pressured manufacturers to settle on a single common socket design. As a result, utilities could purchase meter units from any number of vendors and be assured they could be easily installed at any customer site. These standards have also been embodied by regulatory commissions in their rules for service. Consequently, regulated tariffs very explicitly specify the features and standards that all approved revenue quality meters must meet.

The second phase of meter standards developed following the introduction of personal computers in the early 1980's. Capitalizing on the capabilities of microelectronics, most of major meter vendors developed their own proprietary electronic meter reading capabilities. Instead of paper meter reading books that required a technician to manually record the dial reading from each customer site, electronic meter books allowed meter readers to physically connect to the meter and electronically download the meter readings or to key-enter the readings using an electronic keypad. Electronically downloading or key entry of data was faster, it eliminated transcription errors and the need to re-enter data from the meter book to the billing system. Unfortunately, each meter manufacturer developed their own connection methods and proprietary protocols (data formats) for downloading and storing data. Lack of compatibility among meters forced meter readers to carry multiple devices into the field, which was both costly and impractical. In the early 1980's, a utility consortium eventually developed a standard electronic meter book that could be programmed to read all meter protocols.

Phase three in the development of meter standards was introduced during restructuring of the California electric market. In 1997, the California Public Utility Commission (CPUC) in Decision 97-12-048 ordered the creation of a Permanent Standards Working Group (PSWG) to review and recommend permanent meter standards. The PSWG looked at the physical structure of metering systems and equipment as well as the data flows between users (utilities, customers, alternative providers, etc.). Because the CPUC previously endorsed utility and private providers of meter and billing services (unbundling), the PSWG scope of work also addressed requirements for a fully competitive industry structure. Figure 2 provides a schematic of the hardware / data flows addressed by the PSWG, where the numbered tags identify specific interfaces for which standards were eventually developed. Table 3 identifies and describes each of the interfaces.

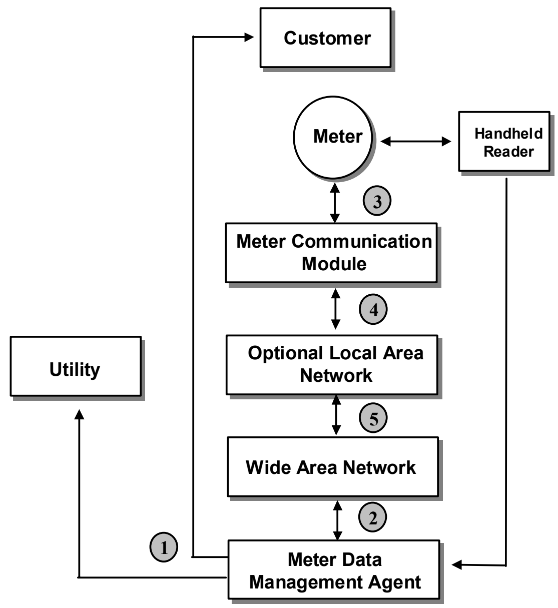

Figure 2. Metering System Hardware / Data Flows and Interface Points

Table 3. Overview of the California PSWG Interface Standards

Interface ID	Description – Standards Developed to Address the Following Functions
1	Data communications interface between the Meter Data Management Agent (MDMA) and market participants (utilities, customers and other service agents). Standards addressed detailed data editing, quality, timing and formats. Electronic Data Interchange (EDI) standards were also addressed.
2	Data communications interface between the MDMA and the Wide Area Network – no new standards developed. ANSI C12.19 standards to govern device data format
3	Interface between the meter and communication modules that attach to the meter. Standard optical port interface requirements (ANSI C12.18) were recommended to govern connections in manual systems. Minimum visual display at the meter was also specified. Hardware or other requirements dealing with electronic systems for this interface were not recommended due to lack of industry consensus and immature market development.
4	Data communications interface between the local area network and the meter communications module.
5	Data communications between the local and wide area networks. This was determined to be a bundled function that could be unique to individual meter vendors – no standards developed.

One of the fundamentals underlying the restructuring and standards development process was that all of the companies participating in the competitive energy market would eventually depend upon advanced automation, communication systems, and electronic linkages to transfer data and coordinate business processes. Regulations and standards developed to support competitive energy market requirements inherently addressed business processes designed from the outset to embrace electronic commerce.

Basic economics and stringent processing requirements provide two compelling reasons why customer meters will also require their own communication links. To be economically viable, conventional manual and remote meter reading techniques require contiguous, highly saturated populations of customers. However, in the competitive market it is more likely that customers for most alternative providers will be widely dispersed over large geographic areas. Communication-based metering systems hold an economic advantage under these conditions.

However, it is the meter data processing requirements that provided some of the most compelling reasons for communication-based systems and a focus on data rather than hardware standards. The volume of meter data and critical timing associated with key pricing and settlement tasks require a communication link to each customer. Communication links to individual meters allow usage data to be collected automatically, as needed, to support a variety of system operating, customer billing, and other new service options not feasible with manual or remote metering systems. For example, simple things like allowing customers to specify their own billing cycles are impossible without systems that provide the ability to read meters independent of a fixed meter reading route. As a consequence, there was an underlying assumption that in the long term, meters used to support the restructured market would almost certainly include communication capabilities.

In an effort to formalize the move to communication-based meters and electronic commerce, states like California and Pennsylvania pushed for the adoption of revised EDI (Electronic Data Interchange) standards to specifically support competitive energy transactions. The proposed EDI standards regulate the information linkages and data exchanges between all market participants. The California-Pennsylvania effort recognized that energy markets must be prepared to support national providers without fixed territories or geographically constrained service franchises. The necessity to support customers over extensive geographical regions added further confirmation to the move toward communication-based metering systems.

The PSWG working effort addressed an extensive range of hardware, software and business process standards. With a working group that included representatives from all of the major vendors, interest groups, labor unions, California and non-California utilities and alternative ESP’s, it became apparent early on that decisions reached for the California market would have application elsewhere. With the start of restructuring efforts in other states, many of the participants in the California effort looked for a way to consolidate future standard-setting proceedings. Vendors and manufacturers were concerned that different hardware and procedural standards from state to state would drive up the cost of doing business and make product development difficult. They were also concerned that numerous standards-setting efforts would thwart their efforts to develop uniform products for all of their North American, European and other markets. All participants with interests in the utility market were concerned that independent regulatory proceedings would waste valuable time and not lead to constructive improvements.

Under pressure from numerous constituents, the Edison Electric Institute (EEI) in early 1999 organized a national effort to develop a Coalition for Uniform Business Rules (CUBR) for the entire electric industry. The stakeholder group organized for this effort included many of the same participants from the California restructuring effort. Eventually, the working group expanded to include over 90 entities representing utilities, vendors and other interested parties from throughout North America. Using private facilitators, the group transitioned from EEI to become the Uniform Business Practices Working Group (UBP). In 2000, the UBP released two volumes (Table of Contents, Appendix A) of recommended business practices and standards, one of which dealt entirely with unbundled metering the other with business practices for the retail energy market. The California PSWG evaluation reports and standards formed the basis for the UPB effort. Those standards are still being revised and expanded. The California and UPB standards are now viewed by my many in the industry as the national standards by which metering and meter related practices should and will be guided.

3.0 Customer Interface – Providing Information and Services to Customers

Issues: Customer Interface

- Meters don't provide customers with meaningful information to make decisions.
- The link between meters and demand management programs has not been established.
- There is a need for a customer interface that links the meter to customer energy control technologies.

The format and methodology for presenting meter-related information to the customer is technically not considered part of the typical meter system. Today, communication links from the meter deal almost exclusively with the transport of data to an intermediate system for cleaning, editing and preparation of data for billing and customer presentation. Separate independent systems, separate designs, and entirely different economics govern how data are transported and presented to customers. The exceptions are the few commercial and industrial customers that take data directly from their meters via utility or privately provided interconnections to support unique facility and operating applications. Customer interface issues generally require a completely different evaluation model (behavioral) than metering systems (engineering).

With few exceptions, meter systems and control systems (load management and energy management) also now employ completely independent communication and processing capabilities, regardless of customer group. While control systems may utilize information links tied to the meter provided data, utility provided systems are not usually directly interconnected. Metered usage data almost always passes through a processing step performed by an energy management system or gateway device, which includes the instruction set to activate and regulate any control action.

There are two major exceptions, one residential and one commercial, which include integration between the meter and control devices. The residential exception is the whole house disconnect (residential only) switch. Designed to fit into a collar plugged in behind a conventional revenue meter, whole house disconnects are a specialty application employed by only a few utilities to control serious 'dead beat' customers. The commercial exceptions usually occur only with high-end energy management systems, in highly sophisticated facilities. However, even in those systems, the meter and control systems use independent communication systems.

As a result, the remaining material in this section only provides a very superficial review of the history and issues surrounding the customer interface.

3.1 The Residential Customer Interface

In the early 1980's vendors began to incorporate microprocessor and communication technologies in metering and other utility systems to upgrade the capability to collect and use information to monitor and manage system performance. Federal passage of the Public Utilitiy Regulatory Policy Act (PURPA) and a myriad of California legislative initiatives spurred the effort to develop more sophisticated supply-side and demand-side planning tools. Advanced metering and communication equipment was necessary to facilitate the data gathering to support this effort.

Early experience with microprocessor and communication applications in financial, transportation and other deregulated industries produced significant gains in productivity and often led to new applications and more efficient business process. Collaborative field trials of advanced metering and communication systems by EPRI, the Commission, and many of the major California utilities produced similar encouraging results. System operating and planning improvements brought about by more sophisticated load research, distribution automation, load management and other applications of advanced technologies convinced many that utilities could achieve some of the same benefits being achieved in deregulated industries.

> "*The arrival of microelectronics and communications technology for power distribution systems promises a new era in the way utilities deliver electricity to customers. Automating many of the functions now performed by electromechanical switches and relays will improve reliability, reduce costs, and offer greater opportunities for conservation and load management.*"[10]

To further develop and pursue the opportunities from advanced metering and communications, equipment vendors, utilities (gas, electric and telecommunication) as well as many other equipment and service providers (home automation, security, entertainment, banking, etc.) began a series of pilot programs during the early 1980's through the mid 1990's to evaluate the technical and financial feasibility of different customer service models. Electric and gas utilities had large, stable markets, captive customers, good public reputations and products without substitutes. From the utility perspective, new technologies provided an

10. "Editorial", EPRI Journal, May/June 1984, Clark Gellings

opportunity to generate new sources of revenue and profits by tapping their existing customer resource pool. Although none of the pilot programs succeeded in advancing the implementation of advanced metering, they did produce results in two significant areas: (1) engaging the customer produced productive demand-side benefits, and; (2) more timely, electronic meter data created opportunities for business process savings throughout the utility supply chain.

Because metering provided the physical connection to the customer premise, it was viewed as a logical connection and starting point for most technology developments. In this pre-Internet environment, almost all pilots focused on the need and value of two-way or bi-directional communication with the customer meter. Some of the earliest field trials quickly concluded that telephone and other advanced communication-based meter reading systems could not be economically justified solely on potential savings from reduced meter reading costs alone. Either costs had to be reduced or other services and applications had to be developed that could share the technology infrastructure. Thus began a search for the ultimate customer interface.

In a landmark study that started around 1980, AT&T (pre breakup) conducted a structured energy services and home shopping market field trial with two electric and gas utilities. Using television sets (personal computers had not yet been introduced) outfitted with custom configured set-top boxes, AT&T provided a controlled group of utility residential customers with time varying rates, integrated load control options, home shopping, weather services and electronic banking applications. Individually and collectively, the AT&T application set was far more advanced than anything utilities had ever offered. Economic evaluation following the trial concluded that although the energy applications had very high value, they could not generate sufficient revenues to fully pay the technology and communication infrastructure costs by themselves. Although the actual customer results were not made public, AT&T concluded that energy applications were the most highly valued of all applications and that they could be used to justify and fund most of the technology infrastructure costs, making it possible to then offer all other services at close to marginal cost. Unfortunately, the staff recommendation to offer these services nationwide fell victim to the 1984 court ordered breakup of AT&T, which occurred several months following the field trial.

The AT&T pilot was only one of many advanced metering / electronic commerce trials (Table 4) that initiated a search for systems that might expand customer oriented information-based services. While the 'customer interface', or method for presenting information and service choices to the user was a key focus of all system efforts, other common elements included metering, communication, home automation, control technologies and electronic banking and commerce.

The field trials identified in Table 4 represent only a sampling of the most significant projects. Collectively, these and the remaining projects represent several hundred million dollars and years of investment by some of the largest and most sophisticated technology, communication and service companies. Although much of the development work produced no lasting physical product, many of the trials produced results that helped to further advance the role of information to customers and the potential value to the utility industry itself.

Table 4. Utility Advanced Metering and Electronic Commerce – Pilot Programs

1980-1985	1986-1990	1991-1995
• AT&T • South Eastern Electricity Board • TranstexT (Southern Bell)	• Pacific Bell - Project Victoria • TranstexT (2) • Bell Atlantic - home automation • Orange & Rockland • Southern California Edison • Florida Power and Light • Baltimore Gas &Electric • Northern Telecom • Pacific Telecom - US West • Spartan Electric • National Rural Electric Cooperative Association and Access Corporation • ITI - home security • Southern Company - EnerLink	• Pacific Gas &Electric Company, Microsoft, and TCI • Lucent - Public Service Electric and Gas trial • Ameritech - Wisconsin Electric • TranstexT (3) • Central and South West Communications • Pacific Bell - SDG&E • Philips Home Services –(smart phone) • UtiliCorp / NEST • Verifone • RCN (LEC) • AT&T Wireless • Metricom • Ericsson, Cox Cable • Tampa Electric Company (TECO) - home automation • Ontario Hydro • Videotron - UBI • Scientific Atlanta - Maingate • ET -MainStreet

The TranstexT pilot trials, referenced in Table 4, provide one of the best examples of how advanced metering, communication links and information can be combined and how this 'technology package' impacts customer response. It is important to note that all of the projects identified in Table 4 include various combinations of technology and information. However, an important and often missing element of many research projects was how the information was presented to the customer and what tools were employed to empower the customer to act. The last two features are often referred to as the 'customer interface'. The TranstexT pilots were distinguished from almost all of the other pilots conducted during the 1980's and 1990's by their approach to the customer interface.

TranstexT initiated some of the most sophisticated and most heavily evaluated of all pilots. They were also one of the only pilots that emphasized research on customer response to technology and information. TranstexT focused on a turnkey approach to fully automated residential response to a dispatched time-of-use rate. Their pilots had three major components:

1. Customer Interface - A sophisticated electronic thermostat with a multi-function display panel was used to provide normal thermostat controls, provide information to the consumer and provide an input device for capturing customer energy service - value tradeoffs.
2. Rate Design (Incentives) - The rate design combined a standard three-part (peak, shoulder and off-peak) time-of-use rate with a dispatchable 'super peak rate'. The super peak rate was essentially equivalent to a proxy for real-time market prices just proceeding and during a stage 2 to stage 3 event. Super peak prices could often exceed the off-peak rate by as much as a factor of 40:1. The rate design was heavily influenced by and intentionally designed to mirror features of real-time pricing.
3. Technology - Pilots included advanced interval metering with telephone communication links that also connected to a powerline gateway into the home. The powerline gateway allowed the customer to obtain real-time information on their usage and an estimate of their accumulated energy cost through the current billing period. The gateway also provided the link for automatically controlling HVAC, water heating and other loads automatically in response to pre-programmed customer 'service value - energy cost' tradeoffs. Cumulative total energy cost during the billing period was also provided during selected trials.

Under the TranstexT pilots, customers were presented with information on their own energy use (appliance saturations) and usage patterns. They were then presented with options, relative to a dispatchable TOU rate, for controlling their monthly energy bill. A template matrix was used to assist the customer in making tradeoffs between comfort and convenience and cost. These tradeoffs were programmed into a smart thermostat that automatically translated customer comfort and convenience preference settings into 'load control strategies'. Table 5 summarizes results from the final trials conducted by TranstexT at American Electric Power Company (AEP) and Gulf Power Company. Customer response provided statistically validated load and energy impacts in summer and winter as well as consistently high customer acceptance rates. Although not depicted in Table 5, customer continuation on TranstexT pilots regularly exceeded 95%.

Interestingly, both AEP and Gulf Power made decisions supported by conventional regulatory cost benefit analysis to pursue full implementation of the TranstexT technology. Unfortunately, like AT&T, program expansion decisions came too late in the TranstexT business cycle. TranstexT ran out of funds and ceased doing business shortly after the conclusion of the Gulf Power trials in the early 1990's. Several years after TranstexT closed its doors, Scientific Atlanta resurrected a similar system called MainGate that incorporated similar functionality in an updated technology package. However, like Transtext and AT&T, Scientific Atlanta also terminated its pilots and technology development efforts in the mid 1990's. Finally, in the late 1990's, a company called Comverge purchased the Scientific

Atlanta load management business unit, which included rights to the MainGate system. That system has now been reintroduced and Comverge and Gulf Power have entered into a new contract to pursue the original implementation effort.

Table 5. TranstexT AEP and Gulf Power Pilot Program Results

	AEP Appalachian Power	AEP Columbus Southern	AEP Indiana Michigan	Gulf Power
Test Group	160	149	124	242
Control Group	60	60	50	195
Rates ($/kWh)				
Low Price	$.004	$.007 (winter)	$.020	$.035
Medium Price	$.034	$.033(winter)	$.061	$.046
High Price	$.102	$.107 (winter)	$.162	$.087
Critical Price	$.152	$.160 (winter)	$.244	$.288
Avg. Impacts				
Winter Peak	3.5kW	6.2kW	6.6kW	2.9kW
Winter Energy	Insignificant	5%	Insignificant	< 1%
Summer Peak	1.5-2.0kW	1.5-2.0kW	1.5-2.0kW	1.8-2.2kW
Bill Reduction	11.6%	10.4%	14.9%	13.6%

There were two major efforts in the mid-1990's following the TranstexT field trials that further attempted to develop the residential interface and tap what was perceived as a large, lucrative market for energy and other services. AT&T mounted another well-structured field trial with Public Service Electric and Gas Company (PSEG) in the mid 1990's that turned out to be a technologically advanced version of its original trial some fifteen years earlier. At about the same time, Microsoft, Pacific Gas and Electric Company (PG&E), and TCI (cable TV company) mounted their own trial. Both trials were well funded. Both trials included home automation, load management, security and numerous other applications accessed through a PC-based customer interface. The major differences – the AT&T application was clearly targeted with objectives to position it for large-scale implementation, where the Microsoft-PGE-TCI project was focused more on research and development. Irrespective of their differences, both projects eventually closed their doors without leaving behind much in the way of product or conclusions regarding the value, usefulness or critical design features of the customer interface.

Since 1998, several new industry efforts have emerged to again pursue development of a workable residential customer interface (Table 6). Of these projects, all are designed around a commandable / remotely controlled thermostat. Three of the technologies are commercially available. Both of the Comverge products use a basic device design and algorithm approach originally developed by Honeywell in 1980. Based on the literature and contacts with company representative, none of the companies appear to be conducting basic research to fully evaluate the customer response function.

Gateway oriented devices include home automation and 'net appliance' applications that are best suited for the high-end customer market. Universally, gateway devices are much more expensive to purchase and install with costs ranging from $600 to over $1,000 per unit, excluding marketing and customer incentives. At this cost, they are too expensive for utility demand-side management (DSM) consideration. Over the last 15 years, numerous companies have developed and conducted field tests of gateway devices, all with little success. Besides cost, technological complexity, the lack of a clear value proposition for the customer and more specialized, limited scope devices compete for the customer investment.

Table 6. Current Utility Customer Interface Projects

Participating Companies	Interface	Objective / Status
Carrier / Silicon Energy	Smart Thermostat / Gateway	• Position for the Net Appliance market • Utility load management • Limited field trial (2-3 sites)
NewPower / Coactive Networks	Smart Thermostat / Gateway	• Integrated energy supply and delivery • Utility load management • Limited field trial (prototypes at 3 sites)
Comverge	Smart Thermostat / Gateway "Maingate"	• Price response based load management • Commercially available – Gulf Power primary customer
Comverge	Smart Thermostat	• Conventional load management • Commercially available
Cannon Technologies	Smart Thermostat	• Conventional load management • Commercially available
Lightstat	Smart Thermostat	• Price response based load management • Field trials in progress

Limited function controllable thermostats have greater promise for inclusion in utility demand-side management programs. However, all controllable thermostats rely on 'local control', where the customer ultimately has the capability to override or entirely disable the device. Local control reduces the certainty of potential load impacts, which in turn lowers the cost effectiveness of any related program. Local control also involves system operating issues that have not been addressed by utility research. Improperly designed internal control algorithms and improper dispatching can create two major problems, specifically: (1)

improper dispatching can synchronize customer loads and cause rebounds that produce more severe peaking problems than the uncontrolled diversified load, and (2) improper control algorithms, some designed to address equity issues, can severely constrain heating, ventilating, and air conditioning (HVAC) operations and create comfort problems that jeopardize customer participation. Finally, lack of integration with local metering, often burdens these systems with their own equity issues regarding how to account for and reward or punish customers for override actions.

3.2 Residential Response to Energy Information and Price

None residential trials and non-trial implementations, including those identified in Table 6, collected information to specifically explain how or why customers respond to various presentations of energy data. None of these trials were structured nor did they collect information to specifically evaluate or establish price elasticity.

Most residential price elasticity studies were conducted in the early 1980's and mid 1990's, some of the most significant by California utilities. While periodic studies continue to derive estimated customer price elasticity functions from response to time-of-use rates (TOU) and various rate increases, most evaluation and modeling efforts were limited by the range of price variation examined and by regulatory restrictions that almost always required tests to remain customer revenue neutral – prices could vary but the bill, assuming no change in usage pattern, had to remain the same. None of the price elasticity examinations were directly linked to any meter system implementation effort or to any examination of how data was presented.

A market study conducted for PG&E in the mid 1980's did attempt to establish residential demand elasticity's by end use for various curtailment strategies (Figure 3 and Table 7). The study employed sophisticated 'tradeoff analysis' and experimental designs that linked each customer's appliance inventory to 12 months of historical usage data. Contributions of customer loads on a typical peak day were translated into normalized 'units', which were then translated, based on actual field trial results, into typical impacts.

Customers were asked to respond to randomly selected standardized scenarios of potential curtailments that were tied to dollar reductions in their monthly household electric bill. To respond, each customer had to apportion their load reduction among the inventory of end-uses in their home, using a set of calibrated impact matrices (Table 8) to balance comfort and convenience against the dollar incentives.

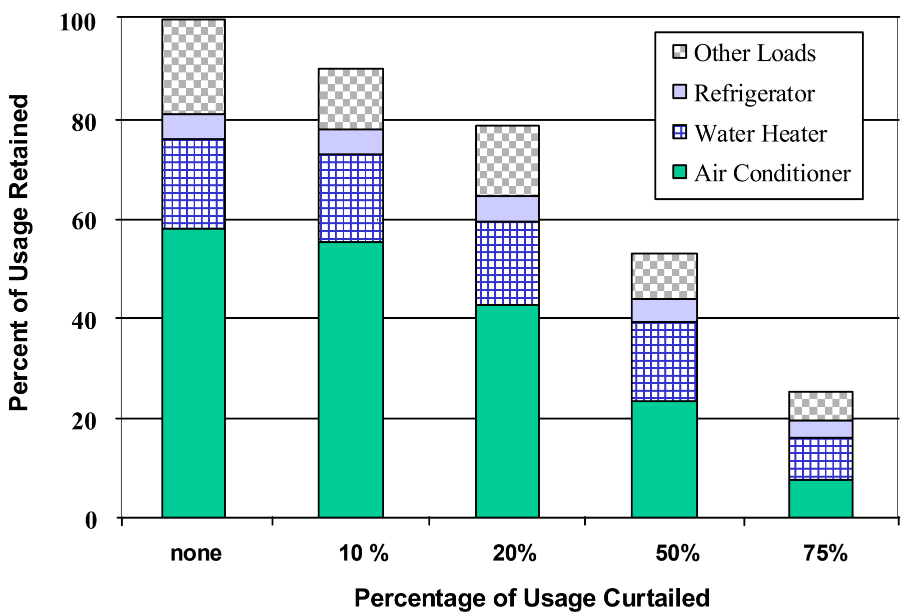

Figure 3. Residential Curtailment Scenarios: Percentage of End-Use Curtailed

Table 7. Residential Curtailment Scenarios: Percentage of End-Use Curtailed

		Customer Selected Percent of End Use Curtailed			
End Use	**Uncurtailed Percentage of Total Load**	**10%**	**30%**	**50%**	**75%**
Air Conditioning	58%	4%	26%	60%	87%
Water Heating	18%	4%	7%	11%	52%
Refrigerator	5%	0%	0%	8%	31%
Other Loads					
•Lights	5%	31%	8%	46%	69%
•Cooking	5%	15%	38%	54%	69%
•Washing / Drying	6%	56%	25%	44%	75%
•Dish Washing	2%	0%	0%	50%	50%

Table 8. Residential Curtailment Preferences by End-Use Service [11]

	10%	30%	50%	100%
Air Conditioning	**10 points** No noticeable impacts on household temperature.	**30 points** Household temperature rises by 3-5 degrees.	**50 points** Household temperature rises by 6-7 degrees.	**100 points** Household temperature rises by 8-10 degrees.
Water Heating	**4 points** No noticeable impacts on water temperature.	**12 points** No noticeable impacts on water temperature.	**22 points** You may run out of hot water after the equivalent of 2 showers or 1 load of wash.	**44 points** You will run out of hot water after the equivalent of 2 showers or 1 load of wash.
Space Heating	**10 points** Household temperature will decrease by 1-2 degrees.	**30 points** Household temperature decrease by 3-5 degrees.	**50 points** Household temperature decrease by 6-10 degrees.	**100 points** Household temperature decrease by 11-15 degrees.

Results from the PG&E Value of Service study included multiple sets of elasticity calculations comparing cost per kWh to load impacts, the duration, timing (time of day and season) and length of various types of curtailments and random outages. Results proved very useful in supply and demand side program / resource planning. In fact a computerized demand elasticity model, produced as a product of the study, provided capability to quickly compute system impacts based on changing program parameters. However, generation supply surpluses in the years immediately following the study substantially reduced both the need and usefulness for this type of planning tool.

3.3 The Commercial / Industrial Customer Interface

Unlike residential, there have been no significant organized field trials structured to examine or develop a commercial / industrial interface. Until the mid-1980's, commercial energy management systems (EMS) provided the only interface option. Several vendors attempted to market specialized load monitors that displayed instantaneous kW demand, however, these devices were functionally limited and expensive.

Beginning in the early 1990's, Internet access to facility data began to supplement conventional EMS offerings. The Internet provided greater flexibility in accessing facility data, particularly for those companies with multiple facilities dispersed over wide geographic areas. In this area, Enerlink (originally a subsidiary of Southern Company), Avista (a subsidiary of Washington Water and Power) and Illinova Energy Partners were three of the

11. [11] Each customer in the survey was provided with a score card that translated their actual end-use appliance inventory and monthly usage into normalized points. Points were proportional to the time dependent usage of each end-use. Each scenario required customers to identify how many points they would take from each end-use to meet the curtailment. Table 8 identifies service and comfort impacts that result from different changes in points. For example, reduce air conditioning by 30% or 30 points and interior temperatures may rise by 3-5 degrees over current thermostat settings.

industry leaders. All three companies provided their clients with access to tabular and graphical metered usage data, the ability to compare load profiles within and across multiple facilities and varying degrees of billing and rate information. Systems evolved incrementally from single facility to enterprise-wide applications that gave corporate management the ability to daily examine facility usage and performance nationwide. Unlike residential systems, commercial and industrial applications were from the start production level systems. Development efforts were rarely publicized and none were part of the collaborative research that characterized other utility industry efforts.

Today, Enerlink, Enron, ABB Energy Interactive, Silicon Energy, utilities, energy service companies (ESCO's) like Honeywell and Johnson Controls all compete in the open market with a variety of system offerings. In almost all cases, the Internet has become the defacto medium for providing access to facility data.

3.4 The Link Between Meters and Demand-Response Programs

With the exception of large commercial customer curtailable / interruptible programs, metering has not been and is still not considered necessary or important to the success of demand–response programs. Most demand-response programs historically have been marginally cost effective. Given the perceived small base of potential demand reductions and assumptions that assign little variation to hourly energy costs, adding meters to a program cost would almost certainly eliminate the program justification. For larger commercial / industrial customers, the meter cost is much less significant, relative to the base of potential benefits and the customer's existing energy costs.

However, this historical perspective has almost always looked at metering for demand-response independent of metering to support other internal utility operating and planning functions. Although the same system needed to implement demand-response pricing programs can also be used to capture operating cost reductions, cost/benefit evaluations treat them as separate, independent systems. Under this approach, technology to support reduced meter reading and other internal business process costs go through a their own cost/benefit analysis. Regulatory analysis standards typically consider only a subset of the business process impacts and never consider any demand-response impacts. Demand-response cost/benefit studies do the same, ignoring all business process impacts. As a result, demand-response price-driven programs that require metering almost never justify implementation [12]. Standalone advanced metering evaluations rarely produce satisfactory results either. When they do, the 'meter only' studies most often justify 'drive by' or other less capable systems that can't provide the communication capability to support the most productive, price-driven demand-response options.

From a conceptual perspective, advanced metering can provide capability to reduce or eliminate many of the historical deficiencies (Table 9[13]) traditionally assigned to demand-response programs. Kansas City Power and Light Company (KCPL), Ameren, and Puget

12. A recent exception was the CEC analysis provided by Professor Borenstein to justify the implementation of real-time pricing for customers with demands exceeding 200 kW.
13. [13] "AMR's Role in Demand Management", a presentation by Roger Levy at the AMRA 2001 Annual Meeting, September 12, 2001.

Sound Energy provide good examples of utilities that have integrated system-wide metering with innovative demand-response options.

For example, engineering estimates, based on an average customer, are used for almost all residential and small commercial and industrial customers to set incentive levels. Meters to measure individual participant response is considered too expensive to justify implementation. Consequently, all participants receive the same incentive, regardless of their actual load contribution.

However, load research and program operating experience show that there are actually wide differences between participating customers. Some customers contribute more load reductions than others, which under a fixed incentive structure causes some to be overpaid[14] and other to be underpaid. Load reductions also can vary substantially based on weather and business conditions, causing system operators to derate or assign higher risk and less reliability to program impacts.

Table 9. Attributes of Demand Response with and without Metering

Program Features	Without Metering	With Metering
Target Loads	Thermal (AC, SH, WH)	Any load
Load Measurement	Estimated - uncertain	Measured - certain
System Operations	Not qualified - uncertain	Qualified – load certainty
Marketing	Qualified participants only	All customers participate
Customer Participation	Passive – no accountability	Active - full accountability
Incentives	• Fixed – not tied to load impacts • Separate from the basic rate	• Paid for performance • Integrated into the basic rate

Incentive inequities and reduced program reliability are actually symptoms that originate with the decision to not meter individual customers. And while the original metering decision was viewed as a cost minimization effort, the problems that not metering creates actually leads to what some view as even higher program and opportunity costs than those avoided. For example, utility and regulatory efforts to fix the incentive equity and other operating problems

14. Many demand-response participants receive incentives for without ever contributing any load reduction. These 'Free Riders' decrease the cost effectiveness of programs. While these customers are often of great concern to regulators, there is another group of customers who are grossly underpaid for their load contribution. T

often lead to a series of ill-conceived program and hardware fixes that in some cases increase costs, reduce actual program potential, and in some cases create other problems, specifically:

- *Participation Restrictions*. To improve load impacts and reduce the likelihood of 'Free Riders', programs are often restricted to customers with minimum annual usage or demand levels. Incentive inequities remain because incentives levels are still based on an 'average customer'. While raising the lower end of the range may reduce the likelihood of 'Free Riders', it does not address differences in load contribution by the remaining qualified participants. However, participation restrictions do create another problem – they reduce the total load available to the program.
- *Hardware Algorithms*. Complicated hardware and software fixes are often used to address the 'Free Rider' issues. For example, some air conditioner cycling programs use smart duty cyclers to customize control to the actual operating time of each individual air conditioner. Simulation studies and load research show that customizing control to an air conditioner that is not on, still yields no load relief. Studies also show that the algorithms may actually create more severe comfort impacts for mid-range customers and those that use setbacks during work hours.

3.5 The Internet as the Defacto Customer Interface

Technological developments during the last five years, the economics of Internet-based applications, and ease of use have designated the Internet as the defacto media for providing the commercial and industrial customer interface. Expanded saturation of computers in residential households will eventually make the Internet the defacto standard for that customer segment as well. In just the last three years, over 100 utilities have developed WEB sites that offer rate information, billing options and a variety of other customer services. Alternative energy service providers, meter data management companies, and other participants in competitive energy markets have also stepped forward with their own offerings.

How does a WEB-based application relate to advanced metering? In utilities like Kansas City Power & Light (KCP&L), which was one of the first to automate their entire system, advanced metering provides updated usage information on a daily basis that is then made available to its customers through a WEB application. At their own convenience, customers can graphically review their energy usage patterns over a range of dates and use the information to conduct or support their own energy audits. Ameren like KCP&L, Sacramento Municipal Utility District (SMUD), San Diego Gas and Electric Company (SDG&E), Bonneville Power Authority and many other utilities currently offer demand-bidding programs that actively engage customers over Web-based applications that are extremely effective based on load and cost criteria. Other utilities, like Puget Sound Energy recently provided hourly pricing and usage information to all of its customers via the Internet. Demand-side impacts are already being reported, just from the information alone.

4.0 The Economics of Advanced Metering[15]

Issues: Economics

- Meters are too expensive.
- Advanced metering systems are not cost effective.

In 1998, during proceedings to examine tradeoffs between interval metering and load profiling, the CPUC considered the following question: "Is an interval meter required for a customer to participate in direct access?" The CPUC concluded that, the initial entry cost (claimed by the UDC's to be anywhere from $400 to $1,000 per meter) to purchase and install meters would prevent some customers from participating. Specifically, the CPUC concluded, "… smaller customers' ability to use real-time pricing is inhibited by existing technology." In effect, the CPUC concluded that advanced metering was too expensive – it was not cost effective for residential and small commercial customers.

In the spring of 2001, the Australian government considered a similar situation in response to the restructuring of their energy industry. In a letter to the Victorian Minister for Energy & Resources, the Federal Minister of Industry summarized the results of earlier consultant studies.

"In the Commonwealth's view, interval metering ..... has the potential to enhance price competition and to provide retailers and customers with time-of-use price signals. Interval metering will also encourage the development of more effective demand-side management techniques. However, I am advised that there is not yet a proven, cost effective interval metering solution for individual customers."[16]

However, a subsequent consultant study several months later strongly challenged the earlier conclusion.

"The findings presented in this report demonstrate conclusively that the Minister has been incorrectly advised in regard to the possibility of mass roll-out of a 'proven, cost effective interval metering solution for individual households.'"[17]

Cost effectiveness, not technology availability or capability, is still the single most substantial barrier to expanded implementation of advanced metering. The contrasting California and Australian conclusions actually illustrate that there two factors that contribute to this problem. One is substantive – how should cost effectiveness be measured and what factors should guide investments in advanced metering? The second factor is institutional and educational –

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15. "Capturing Value, The Future of Advanced Metering and Energy Information", chapter prepared by Levy Associates for Cambridge Energy Research Associates (CERA), Spring 2000.
16. "Smart Meters for Smart Competition, Handing Back Power to Consumers", prepared by Pareto Associates PTY LTD, a report for the Customer Energy Coalition, May 2001.
17. Ibid.

recognizing that in most cases it is the regulators, who may not be well informed regarding metering or the economics of advanced information systems, that make the eventual implementation decisions.

4.1 Traditional Cost/Benefit Analysis

For many electric utilities, metering decisions are usually guided by a '*Standard Practice*' version of the traditional 'capital budgeting model' that was developed about 20 years ago. The Standard Practice uses ratepayer, utility and societal perspectives to compare costs and benefits. In simple terms, the Standard Practice examines the net present value of a potential stream of expected costs and benefits. Investments in advanced metering will occur if the net present value is positive and greater than other potential investment opportunities.

Some utilities may have to consider a slightly different Pareto Optimal 'least-cost' approach. Under this approach, guidelines may mandate that (1) the aggregate dollar value of the benefits must exceed the investment cost, and (2) the investment must also produce an outcome where no one will be worse off - no losers.

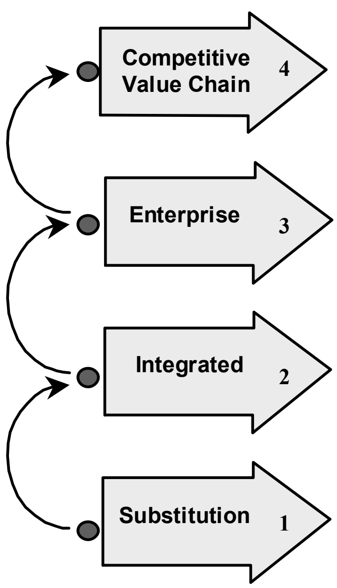
While the preceding approaches reflect slightly different investment perspectives, both strongly emphasize short-term cost minimization. In doing so, both approaches implicitly establish the functionality of existing metering and information management processes as the benchmark standard against which all other alternatives are judged. With this approach, new investment is judged by how well it can satisfy existing business practices at existing costs – the no impacts test. Additional functionality or capabilities are assigned no value, unless it can be provided within existing cost parameters. Regulatory approaches rarely start from or assign value to functional capabilities necessary to support anticipated future customer or market needs. Consequently, metering options that provide more valuable functionality at a higher total cost, immediately become disadvantaged investments. Unfortunately, these evaluations often fail to include all of the related operating and opportunity costs.

New alternative energy suppliers entering competitive energy markets approach this investment decision with an entirely different perspective. Unlike the utility capital budgeting or regulatory approach, there is no existing business practice to anchor the decision process. Therefore, system functionality and the ability to address customer needs is critical. Although metering is an investment in hardware, new entrants to a competitive energy market are really purchasing two things: (1) information and (2) electronic connections. Information is the foundation of their business. Electronic connections provide the means for economically moving information between the market participants. Shifting the focus of the investment decision from hardware to information also shifts the focus of the decision process from the allocation of costs to the estimation of benefits. Rather than looking for why something won't work, the emphasis is on trying to find ways to improve the aggregate benefit pool.

Finally, sophisticated commercial and industrial customers may combine highly quantitative capital budgeting models with more subjective strategic opportunity and competitive analysis. Combined approaches attempt to recognize two factors: (1) the uncertainty of future benefit streams may over or under-weight traditional financial models, and; (2) that staying in business and remaining competitive may require the implementation of certain functional capabilities regardless of costs. Stated another way, end-use customers may be "less concerned about dollar return than with enhancing the company's competitive edge, creating a marketing channel, or improving customer satisfaction"[18].This approach reflects a forward-looking strategic perspective that places high value on flexibility and functional capabilities to remain competitive. The benchmark is not the efficiency of their current process but the efficiency of the newest market participant.

4.2 An Alternative Model - Four Perspectives of Cost/Benefit

Figure 4 identifies four different perspectives for addressing the cost/benefit analysis of advanced metering systems. Perspectives range in complexity from the most simple substitution model to what might be considered the most complex competitive value chain model. The strengths and weaknesses of each produce materially different conclusions regarding advanced metering systems.



Scope	Attributes	Primary Focus
Enterprise plus Suppliers, and other Service Providers	•Values impacts on all participants • Considers all cost savings • Revenues from new services • Strategic orientation • Considers financing options	Long-Run Gain in Value
Internal Integrated **plus** Customer Impacts	• Compatible with PBR • Values redesigned operations. • Considers all cost savings • Revenues from new services	Profitability
Substitution **plus** T&D, Customer Operations, Call Center & planning	• Compatible with PBR • Values redesigned operations • Compares old and new costs • Does not consider new revenues	Cost Savings
Meter Reading	• Compares old and new costs • No value to added functionality • Substitution orientation • Financing options not considered	Short Run Least Cost

Figure 4. Four Perspectives on Metering System Cost Effectiveness

[18] Adapted from "Metering in a Competitive Electric Utility Industry: Another Step toward Electronic Commerce", Newsletter of the Utility Restructuring and Competition Consortium, International City/County Management Association, Volume 2, Number 3/4, Summer/Fall 1998.

4.2.1 Substitution Model

The substitution model embodies a simplified least-cost test, which may sometimes also include a payback criteria. In effect, this is equivalent to the current 'Standard Practice'. Are the net costs per meter per month for the new system less than or equal to the existing system? If the answer is yes, the proposed system provides a positive cost/benefit relationship. If the answer is no, the existing system is judged superior. In many regulatory evaluations, cost comparisons come down to a single comparison of what it currently costs to read a meter. No other costs or benefits are considered. However a focus on cost alone fails to recognize differences in capability between the systems being compared.

The substitution model takes a very narrow, compartmentalized view of the metering function. It usually treats meter reading as a standalone operation. Costs per meter per month for the existing system are derived by dividing the field services costs (direct labor, materials and some of the indirect costs associated with meter reading) by the number of meters. The resulting cost per meter per month then becomes the performance benchmark for all future system comparisons.

For example, the shaded region in Figure 5 depicts the actual high-low cost per meter per month range from a recent competitive bid among five vendors for an electric utility network metering system compared against the existing system meter reading cost of $.74 per month. All costs for the network and baseline systems are for a single monthly kWh meter read, so comparisons between systems are for equivalent capability. From a simple cost perspective, the range of vendor responses (shaded area in the background) have a higher unit cost than the baseline benchmark until contract terms equal or exceed 10 years. Even then, the minor cost differences between the vendor and system benchmark cost may not be sufficient to offset potential risks associated with the contract term or other contractor-specific factors.

To make the comparison more relevant, advantages or benefits from the proposed network metering system need to be identified and matched to the existing system cost. Figure 6 identifies and organizes "range estimates" of benefits from numerous industry studies into functional and organizational categories. Figure 7 aggregates these benefits by category and then superimposes them over the original cost data from Figure 5.

In Figure 6 , benefits consistent with the substitution model are represented by the first set of bars on the left labeled 'Field Service Benefits' which includes reductions in labor, vehicle, and other meter reading costs directly comparable to the $0.74 per meter per month benchmark. The low-end cumulative low-end expected 'Field Service Benefits' of $0.72 per meter per month are still less than the existing $0.74 cost and insufficient by themselves to offset new meter costs and bring the net cost under the system benchmark. Under a conservative approach, moving to a new system with these characteristics would cost this utility more than their existing system. Under a substitution approach this meter proposal is still not cost effective. However, it is also clear that the substitution approach only captures a small fraction of the total benefits available to this utility.

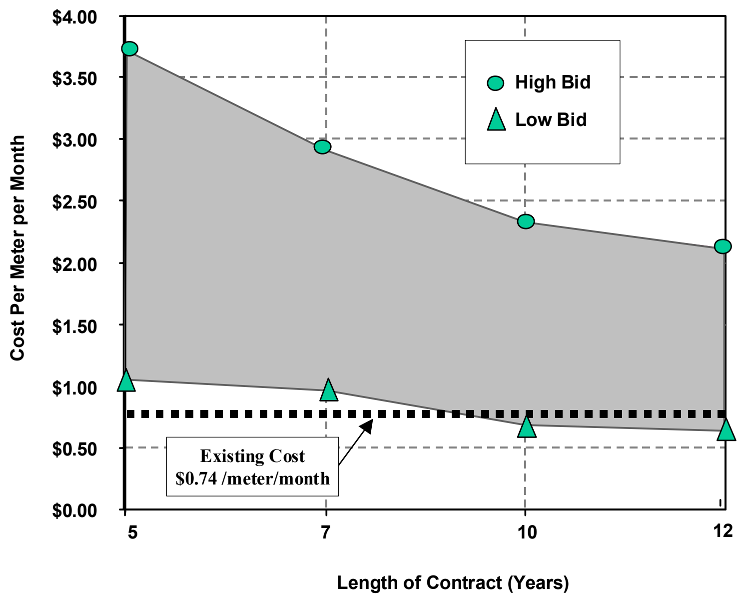


Figure 5. Meter Reading Cost as a Benchmark for Cost Effectiveness

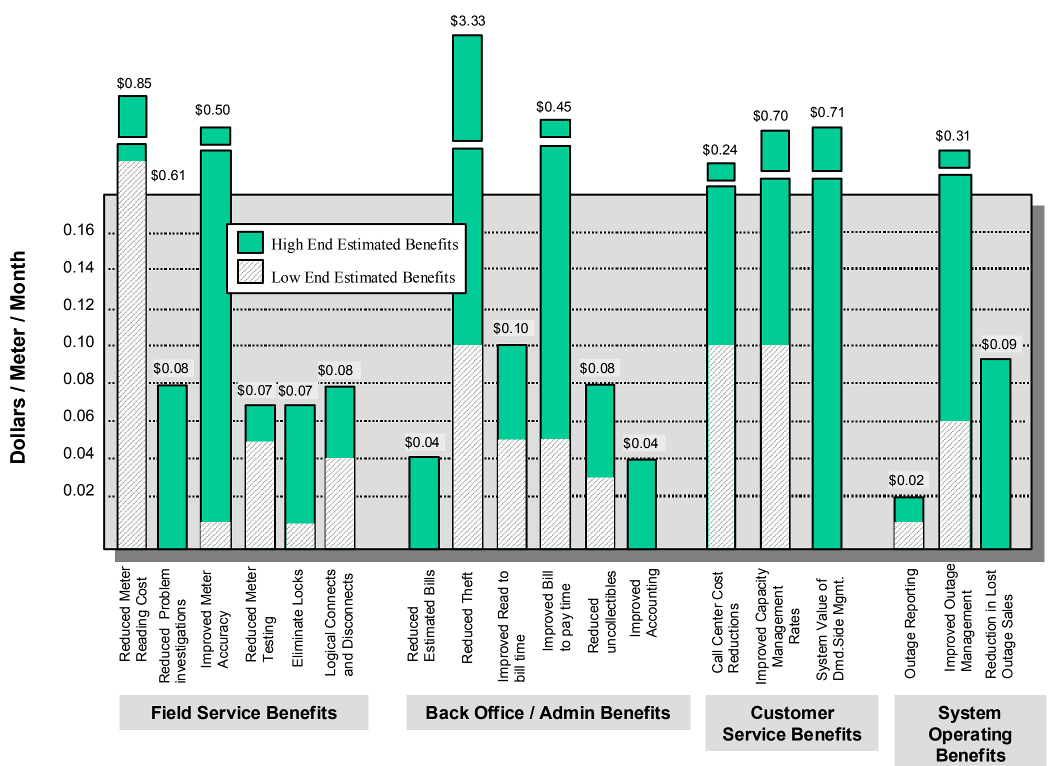


Figure 6. Typical Metering System Benefits

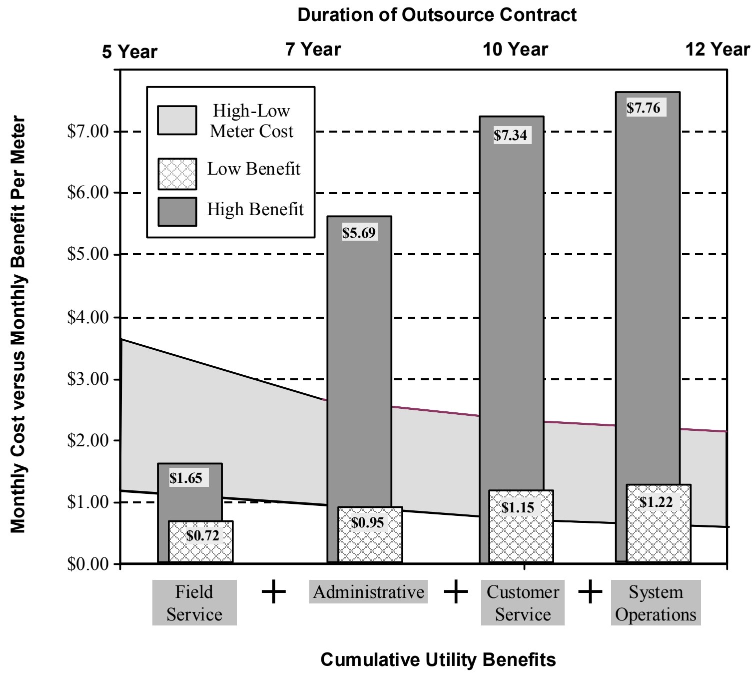


Figure 7. Cumulative Metering Costs and Benefits

Other benefit areas are excluded because the substitution model makes no assumption nor does it establish any cause and effect relationship between meter reading and billing, rates, or other system operations. Figure 6 does not address customer demand-side benefits. Figure 6 also does not account for the opportunity cost of 'not' having the capability that advanced metering offers to quickly adjust rates and demand-response programs to short-term market conditions. A good example is California's' inability to quickly mitigate supply shortages and rolling blackouts with new curtailable or interruptible rate options during the spring and early summer of 2001. Without advanced metering, California utilities had no way to introduce or bill for options with hourly curtailment incentives. Ironically, several of California's regulated utilities actually removed advanced metering from hundreds of customers sites because they did not need them to support their existing time-of-use rates.

This simplistic substitution approach understates the benefits of advanced metering while simultaneously understating the actual cost to the utility of their existing system. No value is assigned to alternative metering systems for adding improved capabilities. This understates the relative value of alternative systems. Correspondingly, no cost is assigned to the existing metering system even where system capabilities currently under perform or can't perform certain functions. This understates the relative cost of the existing system.

The net effect is that new systems are evaluated on the basis of how well they can perform as 'substitutes' for the existing system. Essentially, the substitution model takes a backward looking perspective by assuming that future-metering requirements will be equivalent to what has been required in the past. A better approach would require comparisons of both existing and new systems against a set of anticipated future requirements.

4.2.2 Integrated Model

The integrated model acknowledges that metered data flows through and provides a foundation for most utility back office, customer service, and system operating functions (Figure 8). However, unlike the substitution model, metering is not viewed as an isolated function. Instead, metering is viewed as a data portal that can support a wide range of system operating, customer service and other corporate functions. Consequently, problems or lack of capability in the existing metering system translates directly into costs or other problems for other company operations.

Extending the scope of cost/benefit impacts to the entire company recognizes that there is value not only in the meter data itself but also in the integration of that data as it flows between company functions. The integration of meter data is important for two reasons: (1) it eliminates the need to establish parallel or duplicative sources of data at additional cost, and, (2) integrated meter data also reduces the need for costly adjustment mechanisms that are used to address data inconsistency and coordination problems between operating units.

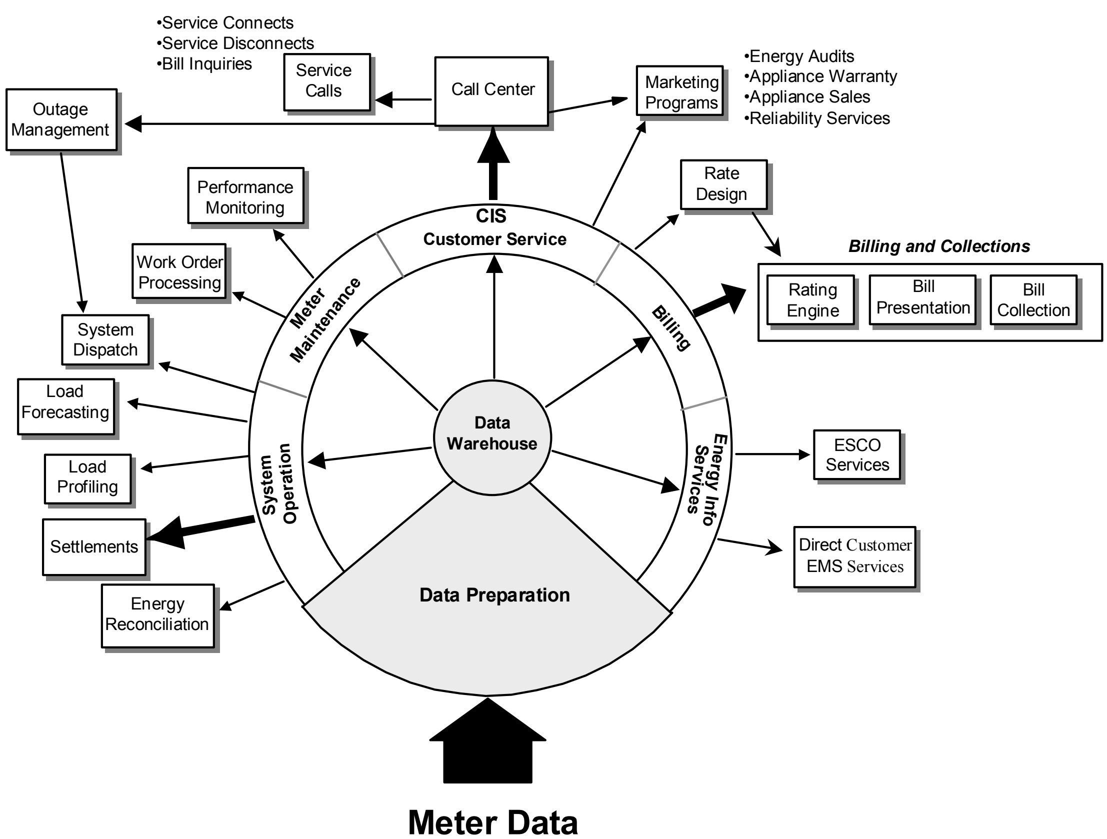


Figure 8. Typical Meter Data Applications

The integrated perspective includes the collective benefits from all operating areas within the company. In Figure 7, the vertical bar to the far right represents the cumulative total benefits across all four benefit categories. From Figure 7, the total expected benefits at the low end now exceed existing system costs by $0.48 per meter per month (benefits of $1.22 less current system costs of $0.74). This benefit level appears to now provide a net reduction in overall system cost regardless of the contract term.

4.2.3 Enterprise Model

The enterprise model extends integrated approach one step further by including potential new revenues from specialized metering and communication services. New revenues alter the cost/benefit evaluation. Economic evaluations usually exclude new revenues, however, charging for new services is not incompatible with performance-based rate incentives.

Figure 9 identifies proxies for seven residential metering and communication services and a range of potential monthly revenues that each service might yield. Information on these options was obtained from utility and vendor sources. Obviously, the expected revenues from each potential service function must be adjusted to reflect expected market participation.

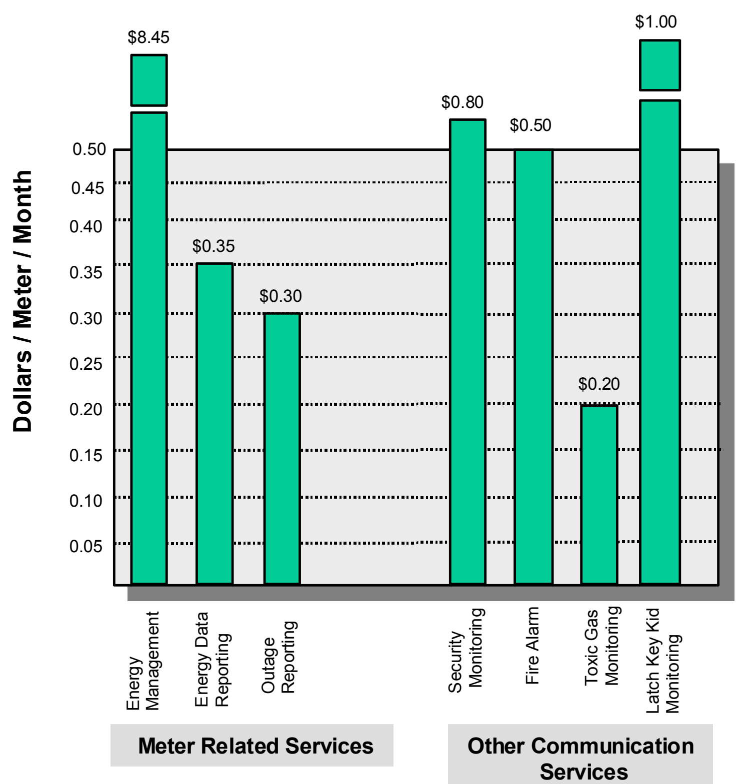


Figure 9. Potential Residential Customer Meter-Related Revenue Opportunities

Although revenue estimates and markets for information services will vary substantially across service providers, valid revenue opportunities exist. Utilities, alternative energy providers and third-party companies have for years offered and charged commercial and industrial customers for meter-related special reads, billing, and other services at rates that far exceed the those reflected in Figure 9.

4.2.4 Competitive Value Chain Model

The competitive value-chain model further broadens the enterprise view to include user organizations and customer participants throughout the energy service industry (Figure 10). Expanding the cost/benefit perspective to end-use customers, third-party ESCO's, wholesale marketers, and other vendors recognizes that the meter acts as the data portal between the user and supplier, which in turn determines the mix of service options potentially relevant and available to each participant. The efficiency and costs of the other service agents and customers are also driven in part by the features of the underlying metering system. Because the meter provides the data flow for all subsequent services, it also functions as a least common denominator or inhibitor, throughout the value chain. For example, conventional utility kWh meter reading systems limit all service providers to the same 28-31 day monthly billing data cycle. Inefficiencies at the headend of the data flow, dictate inefficiencies throughout the data flow.

More significantly, advanced metering and communication creates an opportunity to use dispatchable and real-time rates to dynamically integrate supply and demand management. Integrating supply and demand through price provides a way to substantially improve market efficiency. Advanced metering provides the mechanism to enable this capability.

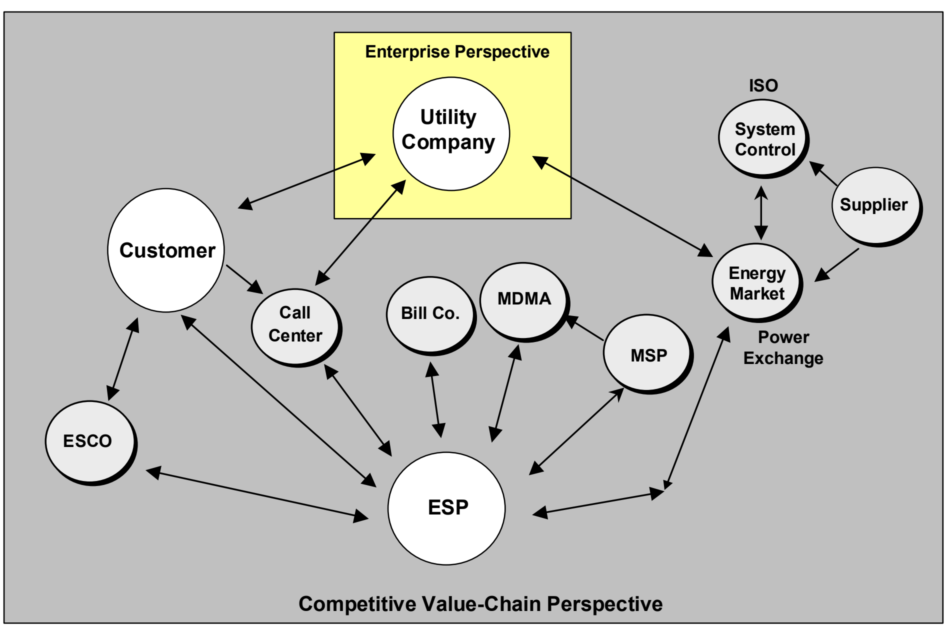


Figure 10. A Competitive Value Chain Perspective of Advanced Metering

5.0 Summary Observations, Policy Issues, and Research Recommendations

Highlighted statements at the very beginning of each of the preceding three sections represent the major issues that collectively are considered barriers to the implementation of advanced metering. The issues at the beginning of each section reflect utility and regulator perceptions based on statements taken from industry reports, through regulatory filings and decisions in rate cases and restructuring proceedings and from other venues such as workshops and industry newsletters.

The 'issues' imply that there are deficiencies in technology development, applications, information or economics that either contribute to or create barriers to implementation. Taken collectively, the issues characterize advanced metering as an immature technology that is not yet ready for widespread implementation. However, information presented in the preceding sections seems to contradict many of these perceptions. Utilities that have fully implemented advanced metering report benefits and operating experience that very different perspective than the commonly accepted industry issues tend to depict.

To resolve major differences in perception, particularly where the differences relate to factual findings (e.g., what are the benefits from advanced metering?) generally requires a two-part response: (1) objective technical and economic research, that may include limited scope field trials, to confirm and/or calibrate the facts, and (2) education, to disseminate the facts, dispel the misperceptions and effect improved decision processes. In many cases, the research options or information necessary to address specific problems is fairly clear. In others, many different options may be available. Additional follow-up research may be required to accelerate commercial development of preferred technologies. Changes in public policy may be required to achieve the greatest public good.

The recommendations that follow emphasize reasonably narrow studies or field trials to enhance commercialization activities, the development of improved methodologies, the generation of information to support education, and other products that more firmly establish the uses and value of advanced metering. This emphasis is consistent with the underlying assumption presented at the beginning of this report, that cost effectiveness, not hardware design or communications, is the principal barrier to implementation.

Research projects to address fundamental, developmental research into metering and communication technologies were not considered either appropriate or reasonable, given the nature of the problem and the structure of the industry. First and most basic, the lack of hardware and communications options does not appear to be a real barrier to implementation. Second, the market for metering hardware and communication appears to be very viable. Some reports even indicate that the market for advanced metering is growing, albeit more slowly than some consider reasonable. The existence of a viable, growing market seems to contradict concerns regarding the sufficiency of meter system options as an issue to be addressed. Industry vendors currently offer a wide range of standard and customized hardware and communication options that appear to actually exceed industry needs. Furthermore, over the last five years, new companies with new technology offerings have entered the meter market at a pace that appears to exceed the failures and reductions due to consolidation.

Finally, metering equipment and system vendors have, since the mid 1990's, begun to de-emphasize the development of less economic, customized systems for individual utilities in favor of more economic, universal products suitable for the international as well as North American markets. Research investments to push fundamental changes in metering hardware and communications for California, even if warranted, would only be productive if pursued as a collaborative effort with one or more industry suppliers. Again, this type of research was not deemed consistent with the identified market barriers.

Recommendations also do not address research into alternative regulatory or competitive models for delivering metering services. While 'data companies' (data-co) or 'metering companies' (meter-co) are concepts with exceptional merit, for the most part they involve issues and concepts that fall outside the material presented in this report. The viability of these alternative delivery models presupposes available hardware and communication options, support for unbundling, and favorable economics. In addition, any discussion of alternative delivery models must address substantial legal and liability issues that go well beyond this report. These assumptions are not fully supported by the existing regulatory or legislative climate in California. In fact, recent legal and regulatory decisions actually challenge the viability of these alternative service models in California. Specifically, legislative action like AB 1421 (September 1999) which prohibits further meter unbundling and AB1x 29 which funded UDC implementation of meters for the largest customers, recent CPUC decisions to approve UDC meter system implementations and pending regulatory action to repeal restructuring make further discussion of these concepts within California both less likely and more appropriate for a separate investigation.

Certain assumptions were made to guide suggestions for research and policy development appropriate to the Commission. In particular, research recommendations emphasized the following:

- Development of methodologies and improved information consistent with COMMISSION integrated resource planning and forecasting responsibilities,
- Development of information to support improved building and appliance standards,
- Activities to accelerate the commercialization of technologies consistent with existing and planned Commission or State programs in load management, conservation and rate design, and
- Activities and tools to educate and enhance both the development and execution of State energy policy

The tables that follow provide recommendations to address each of the barriers presented in the metering and communications, customer interface and economics sections of this report.

Table 10. Recommendations : Metering Technology

Principle Issue Areas – Discussion	Project / Research Recommendations	Product – Commission Policy Implications
A. <u>Technology Availability</u> – Metering and communication technologies are not readily available or capable of supporting the most critical utility applications. Contrary to the perception, metering and communication technology options are readily available to meet most industry needs. Although the market is controlled by four major manufacturers, this is partly the result of consolidation caused by a regulatory constrained market. There are at least 30 or more value-added vendors that actively work with the major manufacturers, creating technologically and cost competitive options for each system implementation. The principle way to spur the development and availability of metering technology is to facilitate long-term, widespread implementation. That will occur only after uncertainties regarding cost effectiveness issues are resolved.	No research or intervention is recommended.	There are no anticipated impacts on current or planned COMMISSION policy initiatives based on the project / research recommendations.
B. <u>Meter Standards</u> – Standards need to be developed to guarantee implementation flexibility and system interoperability. One product from the California restructuring effort was the development of a wide range of meter hardware, data, communication, and other performance standards. The value of these standards was confirmed when they were used as the basis for a national standards development effort that is still under way. These new national standards are endorsed by the EEI, major utilities, most meter vendors, and related industry support groups. State and national efforts to-date provide reasonably consistent standards to address hardware, communication, data standards, data quality and electronic commerce. Additional, new standards will undoubtedly be required in the future, however, caution should be exercised to avoid establishing rules that may curtail innovation and restrict rather than enhance market expansion.	No research or intervention is recommended.	There are no anticipated impacts on current or planned COMMISSION policy initiatives based on the project / research recommendations.

Table 11. Recommendations: Customer Interface

Principle Issue Areas – Discussion	Project / Research Recommendations	Product – Commission Policy Implications
A. <u>Meter information to support customer decisions</u> – Meters don't provide customers with meaningful information to make decisions. Meters have never been designed by themselves to provide information directly to the customer. Meters, however, do provide the data that is necessary to support customer energy information systems (EIS) that, in turn, are designed to support the customer decision process. Although the market is already moving to provide meters and more decision-oriented information to selected customers, there are several real problems that need to be addressed, specifically: No research or published studies have established the value of enhanced information and how it might impact customer purchase and operating decisions. Recent CPUC rulings on the AB1x 29 metering initiative clearly indicate that a misunderstanding of the value of information can lead to premature mandates and tariff rulings that could actually undermine much more productive options. There are few EIS options to address the residential and small commercial / industrial	**Project:** 2.A.1 Establish <u>the Value of Energy Information</u> **Overview:** Timely energy information and price signals can, on their own, be considered a form of demand-responsiveness program. Information and price can incent a customer to reduce load, conserve and make short- and long-run purchasing decisions that impact their load and usage patterns. Like any demand-responsiveness program, the costs to provide information must be evaluated relative to the benefits. **Objectives:** Determine impacts of automated energy information systems on customer load and usage patterns. Assess the cost effectiveness of information as a demand responsiveness program. **Approach No. 1: Field Trial** In conjunction with existing and planned Commission demand responsiveness programs, conduct research to assess residential and commercial / industrial customer demand, usage and other operating impacts with and without access to customer energy information systems. This can be accomplished in two ways: 1. Establish ex-ante control groups for existing programs (e.g. AB1x 29) or	**Product: Project 2A.1** The product of a field trial will be a report that assesses the range of energy impacts due to information alone. Price variation and price elasticity's are not considered variables with this research project. Information attempts to address an underlying question essential to the effectiveness of all Commission conservation, load management and building and appliance standard efforts. Can information help customers better understand the relationship between their usage patterns and energy costs The value of information can have impacts on the following Commission policy areas: Rate Design – information-based rates using advanced meters would encourage greater integration with the supply side and act to more dynamically balance supply and demand. This in turn would impact state resource forecasts. Resource Planning – energy information provides an opportunity to introduce 'yield management' concepts into resource planning. Emergency Response – real-time energy

Table 11. Recommendations: Customer Interface

Principle Issue Areas – Discussion	Project / Research Recommendations	Product – Commission Policy Implications
markets. Almost all major options for EIS are targeted at the largest commercial / industrial customers. Opportunities and the necessity to address system reliability, revised building and appliance standards, and overall equity establish a need for research and development in this area.	programs (e.g. AB1x 29) or 2. Initiate structured field trials that just provide customer energy information systems to target and control groups. While a field trial cannot necessarily control for all variation in format and content, this type of study will produce useful anecdotal information to support future programming and related policy decisions.	information systems, with automatic linkages to EMS, controllable thermostats and other load management devices provides an opportunity to introduce more significant, larger scale demand-response to system emergencies. Building and Appliance Standards – the effectiveness of building response to rate designs and system emergencies can be substantially enhanced if circuits and appliances are designed to better accommodate automated controls and measurement. Favorable outcomes from this project could mandate advanced metering and EIS for customers below 200 kW, similar to what was included in the AB1x 29 program plan
(Continued) **A. <u>Meter information to support customer decisions</u> –** Meters don't provide customers with meaningful information to make decisions.	**Project:** 2A.2 Conduct a Residential and Small C&I Market EIS Feasibility Study **Overview:** Timely, more thorough information on energy usage patterns and cost can motivate short-term operational changes that respond to system emergencies and long-term appliance and building envelop changes that respond to customer cost management. However, EIS is dependent upon implementation of advanced metering, something currently assumed to be non-cost effective for this market segment	**Product: Project 2A.2** Case studies should document aggregate and specific load and usage changes after use of EIS. Capital investment for more efficient end-uses and automatic controls should also be documented. Policy Implications are similar to those identified for. This project is directly related to the project that follows.

Table 11. Recommendations: Customer Interface

Principle Issue Areas – Discussion	Project / Research Recommendations	Product – Commission Policy Implications
	market segment. EIS also has other implications relative to utility 'obligation to serve' and what level of information should be considered 'required' as part of each customer's basic service. **Objective:** Identify existing residential and small C&I EIS options and determine both their costs and impacts. Identify potential EIS development options appropriate for California – potential costs, benefits and delivery options Examine the cost effectiveness and public policy issues inherent in supplying information to consumers. **Approach No. 2: Feasibility Study** Identify and work with existing EIS providers to prepare one or more case studies to document aggregate and specific response / impact due to EIS implementation. Case studies can be integrated into the overall feasibility study. Existing vendors, systems, costs and results to-date need to be identified. Information also needs to be presented to describe potential Commission implementation options, potential sources of funds or areas of collaboration with the CPUC, municipals or others. Cost effectiveness, particularly the dependence upon advanced metering needs to be addressed.	

Table 12: Recommendations: Metering Economics

Principle Issue Areas – Discussion	Project / Research Recommendations	Product – CEC Policy Implications
A. System Cost - Meters are too expensive. **B. <u>Cost Effectiveness</u>** – Advanced metering systems are not cost effective. Both of these issues deal with the cost effectiveness of advanced metering. Cost effectiveness is the principal barrier to the implementation of advanced metering. There are several dimensions to this problem, as evidenced by the data and examples. First, existing regulatory cost/benefit models are too restrictive. There are three major categories of benefits related to and supporting the implementation of advanced metering. Industry experience shows that each category, by itself, can justify implementation. However, only the first category of benefits is usually included in cost/benefit evaluations and then the analysis is most often incomplete. The three benefit categories include: **C. Utility System Process improvements** Customer process and business system improvements Opportunity Costs – capability to support load management for system protection purposes and reduced outages.	**Project:** 3.A Evaluate the Cost Effectiveness of Advanced Metering and Develop an Improved Standard Practice Cost/Benefit Methodology **Overview:** There are no current, thorough evaluations to firmly establish the cost effectiveness of advanced metering. Existing utility studies and regulatory evaluations fail to address lower cost acquisition options. Current studies also fail to include all potential benefits. Opportunity costs are not addressed at all. This project includes two parts, an evaluation and development of a methodology. Each could be pursued separately. A single project structure allows the evaluation to be used as an aide in developing and illustrating the methodology. **Objectives:** Evaluate the cost effectiveness of advanced metering under conventional Standard Practice guidelines. Evaluate the cost effectiveness of advanced metering assuming cost and benefit streams described in the value chain approach described earlier in this report. Evaluate the impact on cost effectiveness of alternative system acquisition and implementation alternatives, specifically contrasting utility purchase and rate base with outsourcing. Develop a revised, more complete Standard	**Products:** • A report detailing the cost effectiveness of advanced metering systems. • A revised Standard Practice cost/benefit methodology There are potential benefits to a collaborative study that includes representation from the CEC, CPUC, utilities and public interest groups. A collaborative study could establish evaluation parameters or benchmarks that would eliminate the need to separately evaluate metering technology and economics for each utility at each related proceeding. A collaborative study would also directly address the educational issues and lack of specific knowledge that currently contribute to uninformed decisions. Results from this study will either pave the way for mass implementation or require follow-up efforts to address engineering and design changes to facilitate commercialization. Mass implementation would have significant implications on all areas of CEC energy policy

Table 12: Recommendations: Metering Economics

Principle Issue Areas – Discussion	Project / Research Recommendations	Product – CEC Policy Implications
	Practice cost benefit methodology. **Approach: Economic Evaluation** This project proposes a classical econometric evaluation of advanced metering systems. To the extent possible, the evaluation should examine each of the following: Costs and benefits by market segment, specifically, large C&I, remaining C&I, and residential as well as combined. The study should also look beyond the basic economics to identify all utility operational, regulatory and related impacts.	

6.0 Acronyms

AC, SH, WH	Air Conditioning (AC), Space Heating (SP), Water Heating (WH)
AEP	American Electric Power Company
AMR	Automatic Meter Reading
CIS	Customer Information System
CPUC	California Public Utilities Commission
CUBR	Coalition for Uniform Business Rules
DSM	Demand-side Management
EDI	Electronic Data Interchange
EEI	Edison Electric Institute
EIS	Energy Information System
EMS	Energy Management System
EPRI	Electric Power Research Institute
ESCO	Energy Service Company
ESP	Energy Service Provider
HVAC	Heating, ventilating, and cooling
ISO	Independent System Operator
KCP&L	Kansas City Power & Light Company
kWh	Kilowatt hour
LAN	Local Area Network
MDMA	Meter Data Management Agent
MSP	Meter Service Provider
PBR	Performance Based Ratemaking
PG&E	Pacific Gas & Electric Company
PSWG	Permanent Standards Working Group
PURPA	Public Utilities Regulatory Policy Act
PX	Power Exchange
RTP	Real-time Pricing
SDG&E	San Diego Gas & Electric Company
SMUD	Sacramento Municipal Utility District
TOU	Time-of-Use
UBP	Uniform Business Practices Working Group
UDC	Utility Distribution Company

Appendix A.

Metering Standards Activities –

Uniform Business Practices for Retail Energy Market

Report Overview

Uniform Business Practices for the Retail Energy Market: Two Volume Report [19]

Volume 1, Uniform Business Practices for the Retail Energy Market, Published November 22, 2000.

Volume 2, Uniform Business Practices for Unbundled Electricity Metering, Published December 5, 2000.

Contents:

Release of UBP Report for the Retail Energy Market

An industry-wide collaborative, working to develop recommended Uniform Business Practices (UBP) for the Retail Energy Market, released a two-volume report that represents over a year's work from a group that includes utilities, energy suppliers, regulators, vendors, consumer advocates and trade organizations. The collaborative worked in two subgroups: one, with representatives from over 90 entities, developed all retail practice guidelines with the exception of metering. The second subgroup, with representatives from 34 entities, developed the practices on unbundled electricity metering.

The UBP Process

In October 1999 a group of interested stakeholders met to discuss this project and establish a list of priority issues for which the development of uniform practices would benefit the industry.

The UBP practices were developed through a series of open workshops, in which diverse stakeholders convened over a scheduled topic and worked through the issues using a "straw man." In many instances, the straw man already existed, as in the case of the Coalition for Uniform Business Rules (CUBR) document. In other instances the groups elected to develop a straw man before the workshops based on a variety of sources documenting existing practices.

The subgroup working on Volume 1 issues used facilitators for their discussions: The Wayfinder Group and Kearns & West, Inc. facilitated the first half of the process and Navigant Consulting, Inc. facilitated the second half. The subgroup working on Volume 2 issues (unbundled electricity metering) was self-facilitated. Both

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[19] UBP memo announcing and describing report contents and release.

groups used a list serve hosted by EEI and a specially created online database to communicate and exchange documents.

The Volume 1 subgroup completed its work in two phases. After developing a set of recommended practices for Customer Information, Customer Enrollment & Switching, Billing & Payment Processing, and Load Profiling as well as an Introduction, Preface, and Glossary, the subgroup paused in February 2000 and issued the chapters for public review. Interested parties were invited to submit comments within a specified timeframe. Twenty-six parties commented. The comments were given to subject-area review teams who had attended the UBP workshops. Their task was to consider every comment in light of the subgroup discussions and recommend to the full subgroup how the comment should be treated. Every comment was isolated and captured in a spreadsheet along with the comment team's recommendations so any party submitting comments could track their submissions. At a July 2000 open, facilitated meeting, the comments were reviewed by the full subgroup and treatment of each comment decided upon. The work of that meeting was integrated into the practices, considered completed, and published to the website August 1, 2000.

In March 2000 the Volume 1 subgroup began working on a second round of UBP issues. The chapters on those issues were completed and issued for public review and comment on August 1. They included Supplier Licensing, Market Participant Interaction: Governing Documents and Performance Standards, Disputes Between the Utility and the Supplier, Creditworthiness, and an Appendix on Single Retailer Model. There were three exhibits: one for Customer Account Maintenance, a Master Service Agreement, and a Billing Services Agreement. Review teams considered comments from 32 parties. The comments were considered by the full subgroup in an October workshop. A final version of Volume 1, with the chapters from both rounds of work, was published November 22, 2000.

The Volume 2 subgroup on unbundled electricity metering began work in March 2000 and met in parallel with the Volume 1 subgroup. Self-facilitated, they developed a substantial technical document on unbundled electricity metering practices, which they published August 1, 2000 for public comment. Thirteen parties commented. In addition to reviewing the comments, the subgroup also began reviewing practices between the two volumes to ensure they were consistent.

In the October meeting, the Volume 2 subgroup completed comment review and disposition. They also met with the subgroup working on Volume 1 to true-up the business practices shared between the volumes. There were practices in Volume 1 that had not been integrated in Volume 2. Following the integration of the identified practices, a final version of Volume 2 was published on December 5, 2000.

Participants in Volume 1 of the UBP Working Group:

AARP
ABB
AES NewEnergy
AGL Resources, Inc.
Allegheny Power
Alliant Energy Corp.
Altra Energy Technologies, Inc.
Ameren Services Company
American Electric Power
American Gas Association
Andersen Consulting .
Arizona Public Service Co
Arthur Andersen
Baltimore Gas & Electric Co.
Bangor Hydro-Electric Co.
KeySpan Energy
Laclede Gas Company
NASUCA
National Consumer Law Center
National Grid USA Service Co.
Nevada Power Co.
New England Power Service Co.
New York State D.P.S. Staff
Nicor Energy, L.L.C.
North Carolina EMC
Northeast Utilities
Northern Indiana Public Service Co.
NRECA
NSTAR
NYSEG

CAEM
Carolina Power & Light Co.
CellNet Data Systems, Inc.
Central and South West Services, Inc.
Central Maine Power Co.
Cinergy Corp.
Cleco Corp.
Columbia Gas of Ohio
COM/Energy Services Co.
Commonwealth Edison Co.
Conectiv
Consolidated Edison, Inc.
Consumers Energy
CSC
Defense Energy Support Center
Detroit Edison Co.
Dominion Gas Distrib. Companies
DTE Edison America
Duke Energy Corp.
Duquesne Light Co.
Dynegy Inc.
ElectricAmerica
ENRON Corp.
Entergy Corp.
Exelon Energy
FirstEnergy Corp.
Florida Power & Light Co.
Florida Power Corp.
Georgia Power Co.
GPU Energy
GreenMountain.com
Idaho Power Co.
IMServ
Insite Services
ITRON
PECO Energy Co.
Pennsylvania Power Co.
Pennsylvania PUC Staff
PG&E Energy Services
PHASER
PHB Hagler Bailly
Portland General Electric Co.
Power System Engineering, Inc.
PPL Corporation
Public Service Co. of New Mexico
Public Service Electric & Gas Co.
Reliant Energy
ReTX.Com, Inc.
Rochester Gas & Electric Corp.
SEMCO Energy, Inc.
Sempra Energy
Shell Energy Services
Sierra Pacific Power Co.
Southern California Edison Co.
Southern Co.
Strategic Energy L.L.C.
Tampa Electric Co.
Texas-New Mexico Power Co.
TXU
U.S. Department of Energy
UtiliCorp Energy Management
UtiliCorp United
Utility.com
Dominion Virginia Power
Virginia SCC Staff
Washington Gas Co.
Wisconsin Electric Power Co.
Wisconsin Public Service Corp.

Total participants: 98

Participants in Volume 2, Unbundled Electricity Metering, of the UBP Working Group

ABB
Alliant Energy Corp.
Ameren Services Company
American Electric Power
Baltimore Gas & Electric Co.
Carolina Power & Light Co.
CellNet Data Systems, Inc.
Cleco Corp.
Commonwealth Edison Co.
Computer Sciences Corporation
Conectiv Power Delivery
Consolidated Edison, Inc.
Detroit Edison Co.
Duke Energy Corp.
Entergy Corp.
GPU Energy
IMServ
ITRON
Nevada Power Co.
Northeast Utilities
Northern Indiana Public Service Co.
PECO Energy Co.
PHASER
Potomac Electric Power Co.
Power System Engineering, Inc.
Public Service Electric & Gas Co.
Reliant Energy
Schlumberger Resource Mgmt. Svcs.
Southern California Edison Co.
Tipmont REMC

FirstEnergy Corp.	Wisconsin Public Service Corp.
Florida Power & Light Co.	
Georgia Power Co.	**Total participants: 34**

The Future of UBP

The two volumes represent an end-point for the collaborative effort hosted by the Edison Electric Institute and co-sponsored by the Coalition for Uniform Business Rules, the National Association of Energy Marketers and the Electric Power Supply Association. It is expected that a standards-setting body will be developed to continue work on business practices. It is also expected the two volumes that comprise the work of the UBP collaborative will evolve under the new organization.

EEI Staff Contacts

Questions about the Report can be addressed to:

- Mike McGrath, Group Director Energy Services at 202/508-5552, mmcgrath@eei.org
- Charles Foster, Manager, Energy Codes and Standards at 202/508-5554, cfoster@eei.org
- Alice Travis, Manager, Project Consulting Group at 202/508-5691, atravis@eei.org
- Elizabeth Stipnieks, Senior Regulatory Analyst at 202/508-5566, estipnieks@eei.org

Benefit Area Supported	Hourly Interval Metering (read daily)	Dynamic Load Profiling
1. *Customer Energy Accounting* - Account for time-varying energy usage.		
a. Electronic Billing Remote inquiry to support electronic process.	Yes	No
b. Other Billing - Support other innovative billing options.	Yes	Proxy only
2. *Customer Information* Support alternative rate options, price signals, and response to billing inquiries.		
a. Price Signals - Accommodate varying price, hourly or TOU.	Yes	Partial
b. Rate Options - Provide data capture to support alternate rates.	Yes	Partial
c. Bill Information - Support customer inquiries.	Yes	Partial
3. *System Operation* - Support communication to automate system operations.		
a. Meter Reading - Automated / network	Yes	No
b. Outage Management - Detection and notification	Yes	No
c. Distribution Automation - Remote connect / disconnect	Yes	No
4. *Equity and Accountability* Support the tracking of energy generation, distribution, and usage.		
a. Theft detection - Detect theft at the customer site.	Daily	Monthly
b. Line losses - Allocate portion of UFE to line losses accurately.	Yes	No
c. System Gaming - Assure reported hourly sales = deliveries.	Yes	No