CALIFORNIA
ENERGY
COMMISSION

REPORT TO THE LEGISLATURE ON ASSEMBLY BILL 29X

REAL TIME METERING PROGRAM

JUNE 2002
P400-02-004F

Gray Davis, *Governor*

CALIFORNIA ENERGY COMMISSION

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Executive Summary

Assembly Bill 29X(Statutes of 2001) provided $35 million from the state General Fund to the California Energy Commission to install either time-of-use or real-time electric meters for utility end-use customer accounts with peak electric demand levels of 200 kilowatts (kW) or greater. The Energy Commission determined that installing real-time, or "interval meters", was the best use of public funds. Real-time meters contain electronic components enabling them to be read remotely by the utility and then to communicate the collected energy use data to a utility's billing system.

Deployment of real-time electric meters implements one of several technological solutions available to ameliorate California's electricity crisis. To meet the mandate of the legislation, the Energy Commission implemented its Real Time Metering Program in May 2001. Through contracts with California electric utilities, the program attempted to install approximately 23,300 real-meters and associated electronic communications equipment, enabling customers to view their hourly load profile and energy use either over the Internet or on a real-time basis. The program was also designed to motivate at least 500 MW of peak demand reduction during its first year of operation.

The table below summarizes which utilities received funding, their respective meter installation quotas, and peak demand reduction potential in their respective service territories due to the meters.

Table 1

Utility	***Contract Award Amount****	***# Meters to be Installed***	***Peak Demand Reduction MW***
Southern California Edison	$16,800,000	12,000	292
Pacific Gas & Electric	$10,277,800	5,900	146
San Diego Gas & Electric	$2,403,960	1,380	33
Los Angeles Dept. of Water & Power	$4,802,290	3,418	107
Sacramento Municipal Utility District	$420,000	300	15
Southern California Public Power Authority • Anaheim, Azusa, Banning, Burbank, Glendale, Pasadena, Riverside	$384,950	274	7
Northern California Power Agency • Gridley, Port of Oakland, Roseville	$100,000	70	1
Totals	**$35,189,000.00**	**23,342**	**601**

*Includes funding from both AB 29X ($33,989,000) and SB X1-5 ($1,200,000) and represents net amount available after deducting California Energy Commission program administration fee (2.5%).

The average cost per meter installation on an overall basis for the Real Time Metering Program was $1,508, including the communications software and access to a web portal that enables a customer to view their previous day's hourly energy usage and demand profile. Each meter installation is estimated to save customers receiving one of these meters, an average of about 26 kilowatts in peak electric demand. This translates to a program cost of about $58 per kilowatt of electric demand saved. As a comparison, other energy efficiency programs funded by the Commission, such as the SB 5X Demand Response Program, offer customers an incentive payment of $250 per kilowatt saved.

To achieve the legislative goal, the infrastructure necessary for a customer to be able to read their own electrical use data had to be in place by the summer of 2001. When available at the end of the summer of 2002, these meters will make possible over 600 MW of peak load reduction after their first year of operating. In the long-term, the program will prepare customers and utilities for a future dynamic pricing structure.

As of the end of May 2002, the utility contractors have completed about 75% of the meter installations and expect to complete substantially all of the installations by the end of June 2002. To ensure that the meter and communication systems are being installed correctly and to verify that customers are able to access their energy use data over the Internet, the Commission is conducting site verifications of 1% of the total number of installations. The site visits are currently still in progress but expect to be completed by the end of summer 2002. An independent measurement and evaluation of the program is also being conducted by Christensen Associates to evaluate the implementation method and verify the peak electric demand savings from the meters. The results of this effort will be available November 2002.

This report fulfills the requirements of AB 29X for the Energy Commission to prepare a report on the implementation of the Real Time Metering Program by June 30, 2002.

Program Report

Background

During the summer of 2000, California experienced sudden increases in the wholesale price of electricity and rolling blackouts during the winter of that year. To respond to this electricity crisis, Governor Gray Davis desired the most viable and immediately available techniques to reduce the state's electric demand and offset the sudden supply/demand imbalance. The initial goal set by Governor Davis for summer of 2001 was 5,000 MW of peak demand reduction through technological solutions available from energy efficiency as well as from simple energy conservation awareness. The focus of this report is on Assembly Bill 29 (AB 29X).

AB29X (Statutes of 2001) signed into law by Governor Davis on April 6, 2001, was one of three urgency bills enacted during calendar years 2000 and 2001, targeting energy use and peak demand reduction to ameliorate Stage 2 and Stage 3 electrical emergencies. The other two bills were Assembly Bill 970 (Statutes of 2000) and Senate Bill 5X (Statutes of 2001). Specifically, AB29X allocated $35 million from the state General Fund for the Energy Commission to provide, within 120 days, either time-of-use or real time electric interval meters to electric utility customer accounts of 200 kilowatts (kW) or greater in peak electric demand. These real-time meters, also referred to as "interval meters," contain electronic components enabling the meter to be read remotely by the utility and then communicate the collected energy use data to a utility's billing system. Larger customers having peak demand in excess of 500 kW for the most part already had interval meters in their facilities, whereas midrange customers in the 200-500 kW class did not. Typical facilities receiving a meter through the program included shopping centers, department or large retail stores, small manufacturing plants, hospitals, and medium to large office buildings.

Before the Energy Commission implemented the Real Time Metering Program, customers did not have access to their own energy usage and peak demand information, providing sufficient notice, so that they could respond easily and quickly to real-time pricing signals. Customers were pretty much relegated to the information received on their monthly bill statements and were, thus, unable to neither accurately or effectively gauge their usage by time period.

The concept of "electricity price elasticity" can be used here to describe this scenario. If a customer does not receive timely electric price signals because they do not have an interval meter, then there is little that they can do to alter their demand for electricity or when it is consumed, i.e., the elasticity is zero. It is much more preferable to have an elasticity that is less than zero, indicating that a customer is able to adjust their demand in response to price signals.

This situation would be possible when the customer has an interval meter that provides the needed information. For the state as a whole, about 30%, or 15,000 MW of California's the total peak electric load of 50,000 MW is attributable to commercial/industrial customers having peak electric demands greater than 200 kW. This is the group affected by the Real Time Metering Program. If demand savings from the meters is estimated to be 500 MW, then the meters have direct influence on 3.3% of the total demand, or an elasticity of –0.033. Although this number is still relatively low, it is still a significant improvement over the pre-existing situation where customers could not respond and the elasticity was zero.

To create the infrastructure that would be the most favorable for taking advantage of dynamic pricing and voluntary load reduction, the Energy Commission developed and implemented a program to install over 23,300 electronic "real-time" meters under funding provided by AB 29X.

Interval meters also possess data access capabilities. Interfaced with the utility's billing system and provided access to the utility's web portal, customers can view their previous day's hourly energy use and load profiles via the Internet. This advanced information capability offers customers a new tool for effectively managing their facility electric loads under the current Time of Use (TOU) tariff. Ultimately, customers will be able to respond to hourly electricity pricing signals in a dynamic or real-time pricing environment that is expected to become available in the near future.

Description of the Technology

AB 29X funded the installation of over 23,300 advanced electronic interval meters, related metering communication devices, and Internet-based end-user information/notification systems for electric utility customers with peak demands exceeding 200 kW. This section describes the metering and communications technology funded by the program. Descriptions of the number of meters deployed by each utility, hardware, software and associated subcontracted services are provided later in this report.

Any metering and communication that the utilities use must be absolutely reliable and cost-effective as well as easy for customers to view their energy information over the Internet. The automated collection of meter data must also integrate easily into the utilities' existing operations and billing system. Several meter manufacturers and software vendors offered products and services that meet these requirements. Figure 1 shows how a typical metering and communications system would operate.

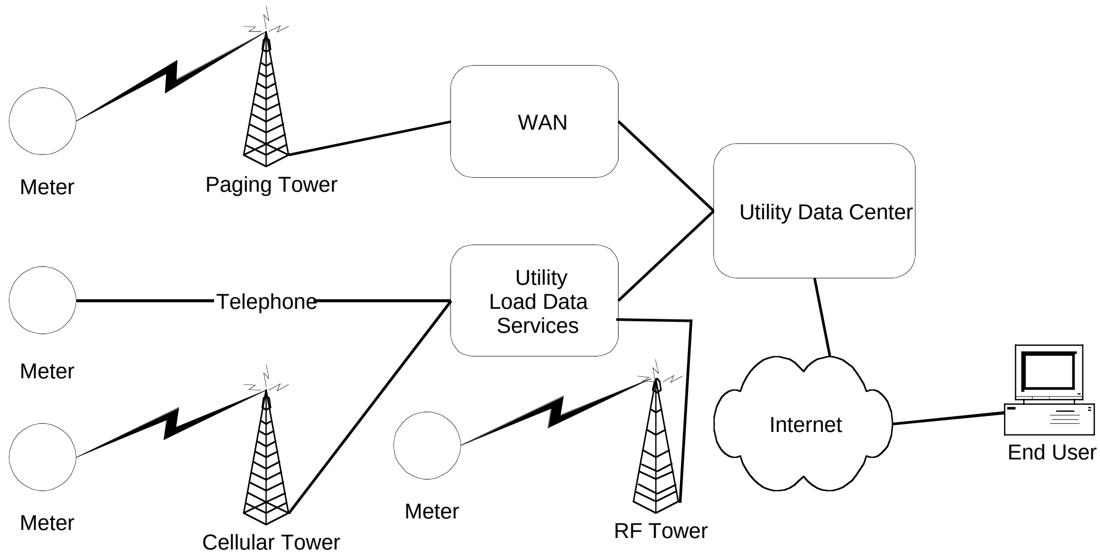

Figure 1 – Typical Meter and Communication Systems Schematic Illustrating the Various Ways Interval Meters Communicate with Electric Utilities and Customers

Figure 1 shows that several communications technologies are available to enable the meter to communicate with the utility. Communications can be done by digital paging, cellular telephone, regular telephone land, or radio frequency. Digital paging was the technology most utilized by the utilities under this program. An explanation of each communications technology is provided below.

Nearly all real-time meters are based upon electronic microprocessor technology and are capable of recording energy usage in at least 15-minute increments, or intervals, by measuring a building's real and reactive power draw. A typical real-time electric meter installation is shown in Figure 2 below. Collected data is stored internally in the meter's Read-Only Memory (ROM) where it can be held for up to 30 days. The bare cost of these meters, exclusive of communications electronics, range from $600 to $800 each.

Figure 2 – Typical Real Time Meter Installation

For billing and revenue purposes, a communications method is needed to transmit 15-minute data recorded by the meters at the customer's facility to the utility's billing system. The meters are programmed to communicate with the utility, usually once every 24 hours, to download collected data to their customer bill processing system. Depending upon installation requirements, one of the following communications methods is used: digital paging, telephone landline, cellular telephone, and radio frequency. A description of each is given below, shown in order of increasing implementation costs.

- Digital Paging: the utility's data center communications system (typically Motorola M32) pages a customer's meter via a paging tower over a Wide-Area Network (WAN) and downloads collected 15-minute interval data very early in the morning, typically between midnight and 6:00 a.m., when other telecommunications traffic is minimal. This method not only virtually ensures that connection to the meter will be made when called, but also minimizes connection costs because it occurs during off-peak hours. The customer's 15-minute data for the previous 24-hour period is then prepared for display and uploaded to the utility's Internet site and posted as accumulated hourly data for viewing by the customer the following day. All customers receiving a meter under this program have been provided with a password to access to their energy usage information over the Internet. The energy usage information seen by a customer is of billing quality and can be immediately used for load management purposes by both the customer and the utility. Digital paging is the lowest priced communications solution at an average cost of about $60 per installation per year.

- Telephone Landline: this method is employed when pager coverage is not available or where cellular telephone coverage is not reliable. The utility's load data services communications system (typically MV90) calls a customer's meter between midnight and 6:00 a.m., downloads the customer's collected 15-minute data for the previous 24-hour period, prepares, and uploads it to the utility's Internet site where the customer is able to view it. Costs for this method are higher than for digital paging because of the need to install a physical telephone line. In some cases, the cost of the telephone line installation can be quite high due to physical impediments to its installation (distance, walls, and other barriers, etc.) This method also requires the customer's consent to install the telephone line in their building or facility. The average cost for this communications method is $100 per installation per year.

- Cellular Telephone: this method is used either where pager coverage is not available or other communications options are more expensive. The mechanics of data collection, transmission, and customer communication are identical to the telephone landline method described above, but uses a cellular telephone network as the communications platform instead of a physical telephone land line. No customer consent is required as the communications electronics are integrated into the meter. This system, however, is more costly to implement because of the cellular network service fee, the average cost being about $150 per installation per year.

- Radio Frequency: this approach is the most expensive to implement and is used only in remote areas where pager or cellular telephone coverage is not available and where a physical telephone line would be too expensive to install. The 15-minute interval data collected by the meter signal is transmitted by radio frequency signal across a private communications network to the utility's MV90 data collection system where it is processed and then uploaded to the Internet for viewing by a customer. Costs for radio frequency installation vary greatly depending upon the number of repeater stations needed to transmit the signal, but are typically several hundred dollars or more per installation per year, including the subscription to a private radio communications network.

Program Development

To implement its Real Time Metering Program, the Energy Commission awarded contracts to the state's electric utilities to install and operate the metering and communications system. Several factors determined the Energy Commission's choices for developing contracts and establishing program implementation and participation parameters.

The first was the short timeframe available in which the program needed to be implemented. The legislation mandated the Energy Commission provide meters within 120 days of signing of the bill. The second was one of meter ownership and the utilities. These factors are discussed in detail below.

Large-scale meter deployment needed to begin by June 1, 2001, to support various peak demand reduction programs from the Energy Commission and California Independent System Operator (ISO) available to customers during the summer of 2001. It was clear that the traditional public contracting process, using either a Request For Proposal (RFP) or Request For Qualifications (RFQ) format, was inappropriate for this purpose. Neither contracting method would have produced the desired results in time because these processes can require up to six months before a contract is awarded. Because of the short time available to implement this program, single, or sole sourcing of contracts, was determined as the only reasonable solution available.

Fortunately, the program was able to take advantage of Governor Gray Davis' Executive Order D-34-01 issued on January 17, 2001, exempting any contracts awarded under AB 29X and SB 5X funding from many of the requirements for sole source contracting. A copy of Executive Order D-34-1 is included as Appendix A of this report. Governor Davis' action greatly shortened the time needed for awarding contracts and enabled the Energy Commission to meet the mandated 120-day deadline. Additionally, the Executive Order invoked Public Resources Code Section 25211, delegating approval authority for any of these contracts to the Energy Efficiency Committee of the Energy Commission. This action also further shortened the time needed to award contracts.

Another factor was that of meter ownership. Under existing California Public Utilities Commission (CPUC) rules, customers cannot, unless they are direct-access customers under deregulation, have ownership of meters used by utilities for revenue purposes. The Energy Commission could not own the meters installed under this program because it would be inappropriate for the State of California to serve as the utility distribution company (UDC) for these customers. As an UDC, the Energy Commission would have the sole responsibility to install, maintain, and operate these meters, as well as coordination with utility customers for the installation of these meters and for coordinating customer billing. Obviously, these tasks cannot be accomplished using state resources and infrastructure. Moreover, it would be totally inappropriate for the state to do so. These functions are clearly better placed with the state's utility industry, and not the California Energy Commission.

Because of these two factors, it was determined that sole source contracts with existing California electric utilities was the only approach available to the Energy Commission to meet the deadline to start large-scale installation of real time meters by June 1, 2002.

After identifying potential utility contractors, program development activities then focused on developing an estimate of California's total meter population impacted by the program and determining a program budget for each utility. Discussions were held with three of the state's largest investor-owned utilities. Each of the three utilities had different funding requirements based upon the number of meters to be changed over within their total respective meter populations and level of infrastructure readiness for reading and processing data from these meters.

Shown in Table 2 below are the requirements for the three California investor-owned utilities (IOUs): Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E). An estimated meter target budget of $1,400 per installation, including communications capability, was initially determined through discussions with prospective utility contractors and was thought to be a reasonable baseline budget. Based upon this budget, it was originally estimated that the Real Time Metering Program could fund the changeover of approximately 25,000 meters.

Table 2
California IOU Meter Population and Number of Meter Changeovers

	PG&E	*SCE*	*SDG&E*	*Totals*
>500 kW				
#Customers w/ Meters	2,800	3,600	600	7,000
#Meters to be Changed	700	3,600	379	4,679
>200-500-kW				
#Customers w/ Meters	5,200	7,400	1,435	14,035
#Meters to be Changed	5,200	7,400	1,435	14,035
Totals				
#Customers w/ Meters	8,000	12,000	2,035	22,035
#Meters to be Changed	5,900	12,000	1,814	19,714
% of Meters to be Changed	74%	100%	89%	89%

The California municipal utilities were not initially targeted to receive any program funds and did not participate in these discussions. However, because the investor-owned utility meter installation quota was only 19,714 meters instead of the 25,000 originally estimated, the program was opened to municipal utility participation. The unused funding was made available to the Los Angeles Department of Water and Power (LADWP), Sacramento Municipal Utility District (SMUD), Southern California Public Power Authority (SCPPA), and the Northern California Power Agency (NCPA). Also, during negotiations of contracts with the investor-owned utilities, the meter installation quota for SDG&E was able to be adjusted downward by about 500 meters due to an April 2001 CPUC decision authorizing them to rate-base the installation of real time meters in the 100 – 300 kW customer class. This left only 1,380 meters, all in the greater than 300 kW customer class, that needed to be changed. SDG&E agreed with the Energy Commission that it was unnecessary to fund meters using AB 29X monies. After awarding the contracts, funding for 800 more meters became available because some of the agricultural account meter installation costs could be diverted to funding provided under SB 5X.

Exhaustive discussions and negotiations with the prospective utility contractors were held during April and May of 2001. This cooperative effort with the utilities resulted in agreement on the final meter installation quotas and contract budgets shown in Table 3 below. Of the original AB 29X allocation of $35 million, approximately $1 million, or about 2.5%, was retained by the Energy Commission for administrative expenses, leaving a net of $34 million for actual program operation.

Table 3
Utility Contract Awards and Meter Installation Quotas

<table>
<tr><th rowspan="2">Utility</th><th colspan="2">Contract Award Amount</th><th rowspan="2">#Meters to Install</th><th rowspan="2">Cost Per Installation</th></tr>
<tr><th>AB 29X</th><th>SB X1-5</th></tr>
<tr><td>Southern California Edison (SCE)</td><td>$16,300,000</td><td>$500,000</td><td>12,000</td><td>$1,400</td></tr>
<tr><td>Pacific Gas & Electric (PG&E)</td><td>$9,777,800</td><td>$500,000</td><td>5,900</td><td>$1,742</td></tr>
<tr><td>San Diego Gas & Electric (SDG&E)</td><td>$2,203,960</td><td>$200,000</td><td>1,380</td><td>$1,742</td></tr>
<tr><td>Los Angeles Dept. of Water & Power (LADWP)</td><td>$4,802,290</td><td>$0</td><td>3,418</td><td>$1,405</td></tr>
<tr><td>Sacramento Municipal Utility District (SMUD)</td><td>$420,000</td><td>$0</td><td>300</td><td>$1,400</td></tr>
<tr><td>Southern California Public Power Authority (SCPPA)
• City of Anaheim
• City of Azusa
• City of Banning
• City of Burbank
• City of Glendale
• City of Pasadena
• Riverside PUD</td><td>$324,950</td><td>$60,000</td><td>274</td><td>$1,400</td></tr>
<tr><td>Northern California Power Agency (NCPA)
• City of Roseville
• City of Gridley
• Port of Oakland</td><td>$100,000</td><td>$0</td><td>70</td><td>$1,400</td></tr>
<tr><td>Totals</td><td>$33,928,971</td><td>$1,259,995</td><td>23,342</td><td>$1,507</td></tr>
</table>

The second phase of program development involved preparing standardized language for the utility contracts. A key contract document is the Work Statement which describes the scope of work to be provided by prospective utility contractors, all of the contract deliverables, and the project schedule. The Work Statement also includes basic functional specifications for the meter and communications systems to be installed under program funding. The major elements of the Work Statement, incorporated as Exhibit A in each of the contracts, are provided below. The complete text of the contract Work Statement is included as Appendix B of this report.

- Acquire, install, operate and maintain advanced interval metering and related metering communications systems.

- Meters shall be California Public Utilities Commission-approved, Direct Access-compatible, billing quality interval meters.

- Provide necessary communications links to each meter to enable customer energy use data to be remotely collected for processing by the utility not less than once during each 24-hour period.

- Provide meter-integrated pulse-initiating hardware or software recommendations for any commercially-available hardware and software that can be purchased and used by customers receiving a meter under this program to directly access their metered energy use on a real-time basis if they so choose.

- Provide customers receiving a meter under this program with access to a centralized web portal that displays their energy use in graphical and tabular format for at least the previous 24 hour period, as well as displaying electricity pricing, electrical system resource status, and other system notices and information.

- Provide customers with information on all applicable demand response and conservation programs that either require or make use of interval metering capabilities. This information shall include CPUC-approved utility curtailable/interruptible rate options, California ISO Demand Bidding and related programs, the 20/20 conservation program, and all applicable demand responsiveness programs mandated by AB 970 and SB 5X and administered by the Energy Commission.

- Provide customers and utility account representatives training on the use of the new metering and end-user information systems.

- Prepare a Project Plan that serves as the basic business plan to procure, test, and install meters and communications system. The Project Plan must include how the information is to be displayed for customers and the utility's customer marketing and education program to ensure the information provided by the metering system is effectively utilized.

- Monthly Progress Reports on program operations and meter installation status that contain the following elements:

  - Coded information on customers receiving a meter to maintain the confidentiality of customer names, addresses, telephone numbers.

  - Aggregated energy usage information by general classification of business type by Standard Industrial Classification (SIC) code.

  - Aggregated energy usage information sorted by zip code and legislative district.

  - Other specific non-confidential details on meter installation as requested by the Energy Commission for program monitoring and evaluation purposes.

- Final Report summarizing metering and communications system implementation activities and a final accounting of all contract costs.

The final step of program development involved negotiating actual contract terms and conditions with each utility, preparing contract documents, and awarding the contracts. The contract negotiation process, begun May 2001, proved to be more time-consuming than anticipated. Several reasons outside the control of the Energy Commission caused this situation to occur.

The utilities insisted on very strict customer confidentiality language requirements in the contract documents. This requirement seemingly contradicted CPUC regulations protecting customer confidentiality with the need for public access to any information generated by a program funded by state monies. Hundreds of person-hours involving Energy Commission management, program staff, Contracts Office, and Legal Office were required to discuss and resolve this issue with the utilities.

Added to the customer data confidentiality issues were uncertainties involving the financial stability of California's two largest IOU's and the ability of the State of California to sign contracts with them. PG&E, one of the prospective utility contractors, had filed for Chapter 11 bankruptcy protection on April 6, 2001, just prior to the start of contract negotiations. SCE also was considering similar action at the time. There appeared to be a very strong reluctance on the part of these utilities to negotiate contracts with the Energy Commission because of their uncertain financial status. Further, shortly after PG&E's bankruptcy declaration, the State's Attorney General issued an opinion advising state agencies against contracting with PG&E, further impeding the contracting process. All of these factors served to greatly delay contract negotiations , and consequently, the start of meter and communication system installations by June 2001.

It was initially anticipated that all contracts could be in place by June 1, 2001, but because of these delays, the last contract was not actually signed until August 22, 2001. The difficult PG&E contracting issue was resolved by contracting with eMeter Corporation of Redwood City, a Metering Services Provider (MSP) selected by PG&E to administer and operate their Real Time Metering Program. Under this arrangement, PG&E became a subcontractor to eMeter for the meter installation thereby enabling the State of California to avoid any exposure of unspent contract monies to PG&E creditors during the expected bankruptcy proceeding.

The solution to the SCE financial issue required intervention by the CPUC. Because of financial instability within their company, SCE did not feel they had the financial resources necessary to proceed with the program unless the Energy Commission agreed to provide more than the target meter budget of $1,400 per installation. SCE's actual costs for this program were considerably higher because the utility lacked the hardware infrastructure necessary to support data collection and billing operations. It would not have been appropriate to use AB 29X money to fund this type of equipment because it would have been outside of the scope of the legislation. The infrastructure would have to be developed by SCE and installed before the meters could be read and used as the basis for customer billing. Because they lacked this additional critical equipment, SCE's actual costs for the program were closer to $3,000 per installation, rather than the $1,400 offered by the Energy Commission. On May 25, 2001, SCE filed Advice Letter 1549-E with the CPUC, requesting establishment of a Memorandum Account to track, and eventually recoup from affected customers, all incremental costs in excess of that provided by the Energy Commission for installing real time metering and communications systems underAB 29X. On June 28, 2001, the CPUC approved the Memorandum Account for tracking program costs and the rate increase for recouping these costs will be heard for the CPUC to approve as part of SCE's 2003 general rate case. Until the Advice filing had been approved, the utility felt that it was unable to enter into good-faith contract negotiations with the Energy Commission. The SCE contract was the last one to be signed under this program.

Program Implementation and Operation

Before implementing activities, utility contractors were required to submit a Project Plan to the Energy Commission for approval as noted above. The Project Plan is a contract deliverable under the Work Statement and provides the agreed-upon parameters to install the metering and communications system. The elements of the Project Plan are (see Appendix B for more detail):

- Approaches for acquiring, installing, and testing of the metering and communication system, data display system, and ancillary systems for collecting, storing, preparing, and displaying billing-ready energy usage data.
- Final number of customers scheduled to receive meters and communications systems.
- Final budget for meter and communications system installation.
- Implementation schedule.
- Identify end-user training needs and proposed marketing materials.
- Identify key subcontractors, vendors, and other resources utilized to implement the meters and communications system and customer data display.
- Identify possible resource constraints, regulatory barriers, and other factors that potentially could delay or adversely impact implementation.
- Identify measures to mitigate potential delays or adverse impact.

- Identify available demand responsiveness programs, or other programs that, in conjunction with the metering and communications system, will provide information for customers to assist them in reducing peak electric demand and energy use at their facilities.

The highest implementation priority for installation of meter and communications systems was given to customers already enrolled in, or who were on a waiting list for existing demand responsiveness programs. Remaining implementation priority was given to customers based on their facility peak demand, the largest customers receiving the highest installation priority.

Summarized below are the specifics relating to each utility's contract, deliverables, and details relating to implementation of their respective programs. Each utility's web address, where additional information on their respective real time metering programs can be viewed, is also provided.

Southern California Edison (SCE)

- Contract Award: $16,800,000
- Contract Award Date: August 22, 2001
- Contract End Date: July 15, 2003
- Total Number of Meters to Install: 12,000
- Meter Installation Completion: June 2002
- Communication Type(s) and Vendors: digital paging (Skytel Wide Area Network), cellular telephone (various vendors), telephone land line (various vendors), radio frequency (NetCom)
- Meter Manufacturer(s) and Type(s): Siemens S4 (all communication applications)
- Information System Type and Subcontractor(s):
  - Data Collection: SmartSynch M32
  - Data Processing: SCE MV90
  - Customer Relationship Management: Silicon Energy
  - Data Presentation: Silicon Energy
  - Web Presentation Front End: SCE
- Cost Per Installation: $1,400
- Utility Program Name: "SCE Energy Manager" <www.sce.com>
- Demand Response and Load Management Programs/Rates Available to Customers
  - California ISO Demand Relief Program (available only during summer 2001)
  - Optional Binding Mandatory Curtailment Program (OBMC)
  - Base Interruptible Program (BIP)
  - Scheduled Load Reduction Program (SLR)
  - Voluntary Demand Response Program (VDRP)
  - California DWR Demand Bidding Program (DBP)
  - Air Conditioning Cycling Program
  - "Beat the Peak" Load Management Program

eMeter Corporation /Pacific Gas and Electric Company (PG&E)

- Contract Award: $10,277,800
- Contract Award Date: June 6, 2001
- Contract End Date: July 15, 2003
- Total Number of Meters to Install: 5,900
- Meter Installation Completion: May 2002
- Communication Type(s) and Vendors: digital paging (Skytel Wide Area Network), cellular telephone (Pacific Bell), telephone land line (Pacific Bell)
- Meter Manufacturer(s) and Type(s): Siemens S4 (paging applications); General Electric KV (telephone applications)
- Information System Type and Subcontractor(s):
  - Data Collection: eMeter/SmartSynch M32
  - Data Processing: PG&E MV90
  - Customer Relationship Management: Siebel Systems
  - Data Presentation: Silicon Energy
  - Web Presentation Front End: Birdsall Interactive
- Cost Per Installation: $1,742
- Utility Program Name: “PG&E Real Time Metering Program” <www.emeter.pge.com>
- Demand Response Programs/Rates Available to Customers
  - California ISO Demand Relief Program (available only during summer 2001)
  - Optional Binding Mandatory Curtailment Program (OBMC)
  - Base Interruptible Program (BIP)
  - Scheduled Load Reduction Program (SLR)
  - Voluntary Demand Response Program (VDRP)
  - California DWR Demand Bidding Program (DBP)

San Diego Gas and Electric (SDG&E)

- Contract Award: $2,403,960
- Contract Award Date: June 2, 2001
- Contract End Date: July 15, 2003
- Total Number of Meters to Install: 1,380 (>300 kW customers only)
- Meter Installation Completion: May 2002
- Communication Type(s) and Vendors: telephone land line (Pacific Bell), cellular telephone (Pacific Bell), radio frequency (SDG&E)
- Meter Manufacturer(s) and Type(s): Schlumberger Vectron (telephone landline applications), ABB (cellular telephone), Transdata (cellular telephone or RF), Landis & Gyr (telephone landline)
- Information System Type and Subcontractor(s):
  - Data Collection: Energy Interactive M32
  - Data Processing: SDG&E MV90
  - Customer Relationship Management: Energy Interactive
  - Data Presentation: Energy Interactive
  - Web Presentation Front End: Energy Profiler Online
- Cost Per Installation: $1,742
- Utility Program Name: “Governor Davis Metering Plan” <www.sdge.com>

- Demand Response Programs/Rates Available to Customers
  - California ISO Demand Relief Program (available only during summer 2001)
  - Optional Binding Mandatory Curtailment Program (OBMC)
  - Base Interruptible Program (BIP)
  - Scheduled Load Reduction Program (SLR)
  - Voluntary Demand Response Program (VDRP)
  - California DWR Demand Bidding Program (DBP)

Los Angeles Department of Water and Power (LADWP)

- Contract Award: $4,802,290
- Contract Award Date: June 1, 2001
- Contract End Date: July 15, 2003
- Total Number of Meters to Install: 3,418
- Meter Installation Completion: 95%-June 2002; 100%-May 2003
- Communication Type(s) and Vendors: digital paging (Skytel Wide Area Network)
- Meter Manufacturer(s) and Type(s): Siemens S4 (digital paging)
- Information System Type and Subcontractor(s):
  - Data Collection: LADWP M32
  - Data Processing: LADWP MV90
  - Customer Relationship Management: LADWP proprietary
  - Data Presentation: LADWP proprietary
  - Web Presentation Front End: LADWP proprietary
- Cost Per Installation: $1,405
- Utility Program Name: "Automatic Meter Reading (AMR) Program" <www.ladwp.org>
- Demand Response Programs/Rates Available to Customers
  - Experimental Real Time Rate
  - Load Curtailment Credit Program
  - Power Quality Alert Notification: Demand Threshold, High/Low Voltage, Power Outage/Power Restoration
  - Average System Electric Cost

Sacramento Municipal Utility District (SMUD)

- Contract Award: $420,000
- Contract Award Date: June 29, 2001
- Contract End Date: July 15, 2003
- Total Number of Meters to Install: 300
- Meter Installation Completion: June 2002
- Communication Type(s) and Vendors: telephone land line (Pacific Bell)
- Meter Manufacturer(s) and Type(s): General Electric (telephone landline)
- Information System Type and Subcontractor(s):
  - Data Collection: Energy Interactive M32
  - Data Processing: SMUD MV90
  - Customer Relationship Management: Energy Interactive
  - Data Presentation: Energy Interactive
  - Web Presentation Front End: Energy Profiler Online

- Cost Per Installation: $1,400
- Utility Program Name: “Power Manager” <www.smud.org>
- Demand Response Programs/Rates Available to Customers
  - Voluntary Emergency Curtailment Program
  - Demand Response Bid Program
  - Temperature-Dependent Summer Rate
  - Day-, Week- or Month-Ahead Estimating of Electric Costs
  - Average System Electric Costs

Southern California Public Power Authority (SCPPA)

- Contract Award: $384,950
- Municipal Utility Participants: Azusa, Burbank, Riverside, Anaheim, Banning, Glendale, Pasadena
- Contract Award Date: July 20, 2001
- Contract End Date: July 15, 2003
- Total Number of Meters to Install: 274
- Meter Installation Completion: June 2002
- Communication Type(s) and Vendors: digital paging (Skytel Wide Area Network), telephone land line (Pacific Bell)
- Meter Manufacturer(s) and Type(s): Siemens S4 (digital paging); General Electric KV (telephone landline), McAvoy/Markham (telephone landline), Schlumberger (telephone landline), ABB (unknown application type), ITRON (unknown application type)
- Information System Type and Subcontractor(s):
  - Data Collection: each utility has own data collection equipment
  - Data Processing: MV90 in most cases
  - Customer Relationship Management: Planergy International
  - Data Presentation: Planergy International
  - Web Presentation Front End: Planergy International
- Cost Per Installation: $1,400
- Utility Program Name: various <www.scppa.org>
- Demand Response Programs/Rates Available to Customers
  - Real Time Rates (Anaheim, Pasadena)
  - Voluntary Load Curtailment Program (all)
  - Power Quality Alert Notifications (Anaheim)

Northern California Power Agency (NCPA)

- Contract Award: $100,000
- Municipal Utility Participants: Port of Oakland, Roseville, Gridley
- Contract Award Date: August 1, 2001
- Contract End Date: July 15, 2004
- Total Number of Meters to Install: 70
- Meter Installation Completion: TBD
- Communication Type(s) and Vendors: TBD
- Meter Manufacturer(s) and Type(s): TBD
- Information System Type and Subcontractor(s):

  - Data Collection: TBD
  - Data Processing: TBD
  - Customer Relationship Management: TBD
  - Data Presentation: TBD
  - Web Presentation Front End: TBD
- Cost Per Installation: $1,400
- Utility Program Name: n/a <www.ncpa.org>
- Demand Response Programs/Rates Available to Customers
  - Real Time Rates (Roseville)
  - Voluntary Load Curtailment Program (all)

A copy of each utility's real time metering program website home page has been included as Appendix D of this report.

Program Results

This program was designed to motivate 500 MW of peak demand reduction during its first year of program operation and 1,500 MW for the three-year long-term program. The meters installed in the thousands of commercial/industrial customer facilities under funding provided by the Real Time Metering Program impacts about 30%, or 15,000 MW, of California's total peak electric demand of 50,000 MW attributable to all customer classes. The estimated 500 MW of peak demand savings available from the meters represents about 3.3% of total peak that can be saved, much of it achieved from the mandatory migration, as directed by the CPUC, of customers receiving meters to TOU rates. The 1,500 MW longer-term curtailment represents about 10% of the 15,000 MW peak and depends how quickly and aggressively California adopts a concept called "dynamic pricing." This concept covers both real-time pricing and a simpler version referred to as "Critical Peak Pricing" (CPP). CPP consists of traditional TOU pricing 99% of the time, but during the 1% time when power supplies are the most scarce, the utility has the right to add a significant "critical peak price" to the TOU base in order to discourage "needle peak" loads. For medium size customers and others without the benefit of full time facility managers to carefully manage electric loads, CPP may be the most appropriate rate and the easiest to sell.

The balance of the savings were to be captured through utility customer participation in the following programs designed to reduce electricity use during utility on-peak periods.

- Utility Voluntary Demand Response Programs

- California ISO/DWR Demand Bidding Program

- Governor Davis' 20/20 Energy Use Reduction Program

- California Energy Commission AB 970 and SB 5X Demand Response Programs

The main driver for installing real-time meters, however, was the anticipated implementation of real time electric rates. Even more peak demand savings could be achieved had this tariff been available to customers starting the summer of 2001. The CPUC had previously been discussing moving California investor-owned electric utilities from TOU to real time rates for quite some time. The CPUC had an opportunity to adopt a new real time pricing tariff structure in July 2001, but instead opted to remain with TOU rates and further required that TOU rates be mandatory for any customer receiving a real time meter by adopting Decision D.01-08-021 (ALJ Alwyn) on August 2, 2001.

The energy shortages of the summer of 2000 should have highlighted the need for a new type of tariff that went beyond simple TOU rates in discouraging electricity usage at times when supplies are constrained, but were not approved. Real time rates have been in use for several years in different parts of the United States with good results and general acceptance by utility customers. California lags the rest of the nation in this regard. The Energy Commission believes that dynamic pricing is effective for reducing peak electric demand, improving the reliability of the state's electric system, and avoiding the enormous costs of rotating outages. Unlike simple TOU rates, real-time pricing will serve to lower the wholesale price of electricity because the supply/demand balance is improved by reducing peak electric system demand.

Fortunately, customers still have the other four options shown above, for reducing peak demand and energy use in the absence of real-time rates. Customer participation in these incentive-based programs is strictly voluntary. The different programs are either geared toward shedding load during utility peak periods when called upon or are grants for implementing permanent peak demand-reducing projects.

Under AB 29X, the Energy Commission provided funding to enable utilities to develop the necessary metering hardware infrastructure to enable customers to realize peak demand and energy use reduction from current demand-responsive energy efficiency programs and future dynamic pricing of electricity. Shown below in Figure 3 is a graph showing estimated peak demand reduction motivated by the Real Time Metering Program from June 2001 to June 2002.

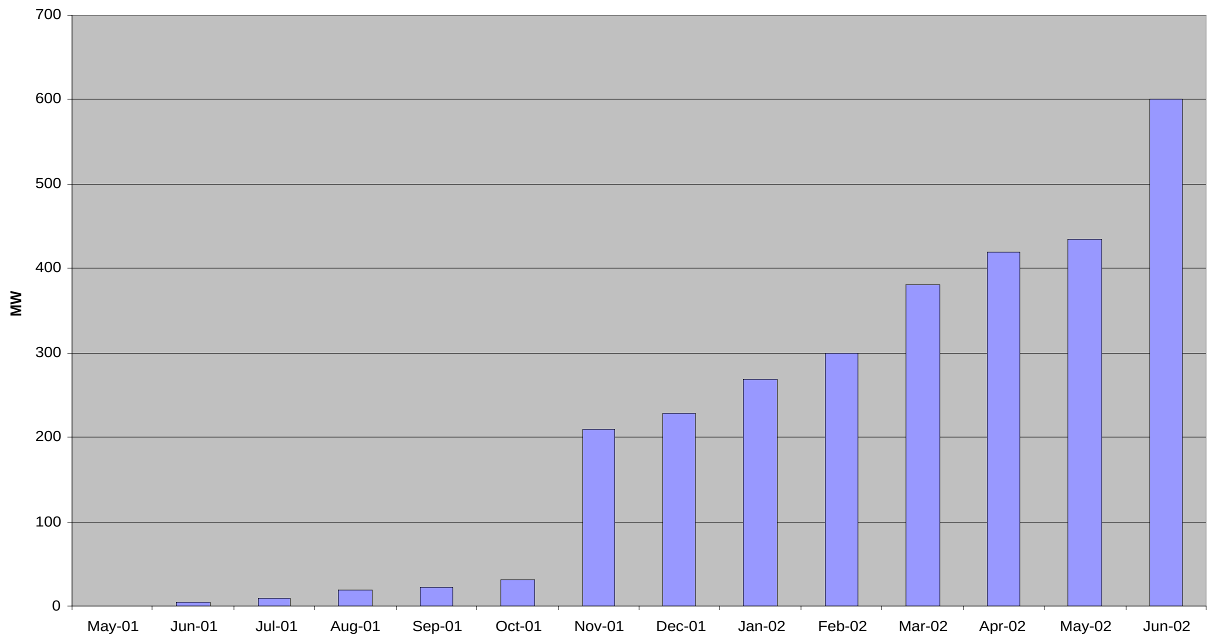

Figure 3 – Peak Demand Reduction Motivated by the Real Time Metering Program

By the end of October 2001, only 31 MW of the projected 500 MW goal had been achieved. There were several reasons for this. First, without a dynamic pricing rate structure, customers simply were not compelled to conserve during critical times. TOU rates did not send out a strong enough price signal to customers to effect energy efficiency measures. Secondly, only 5,330 meters, or less than 25% of the total number meters, had actually been installed and were operational by the end of summer 2001. Contract delays, caused by issues discussed in detail earlier in this report, precluded timely start of meter installation by the utilities at the beginning of summer 2001. However, once the installation process began, meters were rapidly installed in large numbers. Lastly, three of the largest utility contractors experienced meter failures, all in the same model of meter from one manufacturer. During the installation startup phase, a total of about 250 meters from an early production run failed in the field, requiring removal and repair under warranty. Meter defects not only delayed the startup phase for each utility, but also eroded the utilities' confidence in the reliability of this particular manufacturer's meters causing delays during the full installation phase as well. Typically, utilities would "burn in" and test only a sample of new meters arriving in stock. The failure of so many meters necessitated the utilities test 100% of the meters that are delivered from the manufacturer, before deploying them in the field thus adding an extra step before installation. The manufacturer has since corrected the problem by replacing defective communications modules during subsequent production runs and the meters have since proved to be reliable. Fortunately, the number of meters affected were not large, only about 1% of the total number of meters in the program. However, the defects resulted in installation delays as well as additional labor costs for the utility contractors.

As of May 2002, the utilities had collectively installed about 17,000 meters, or just under 75% of the installation quota, and motivated 412 MW of peak demand reduction. It is fully expected that almost all of the 23,300 meters will be installed by June 1, 2002, providing a total estimated peak demand savings for the program of over 600 MW.

The major assumptions used for determining the summer 2002 peak demand savings are as follows. The sources of this information for assumptions affecting IOU peak demand savings are utility monthly reports to the CPUC on program participation and available capacity studies of commercial price elasticities, as well as the Project Plans submitted by the municipal utilities.

- 30% of IOU customers receiving a new real-time meter are migrated by the utility from a flat rate to a TOU rate; 70% are not affected because they are already on a TOU rate.

- 10% of IOU customers in the 200-500 kW class, and 40% of customers in the greater than 500 kW class, receiving a new real-time meter are current participants in a voluntary demand response program offered by their utility.

- TOU rates have at least a 50% wave amplitude, i.e., the difference between off-peak and on-peak rates is at least 50% of the on-peak rate.

- At least 10% of LADWP customers sign up for experimental real-time rate or curtailable rates.

- SMUD achieves its goal of 15 MW of peak demand reduction stated in their Project Plan.

Shown below in Table 4 is a summary of the number of meter installations and peak demand savings to date by utility contractor.

Table 4
Meter Installation and Peak Demand Savings Summary
As of May 2002

Utility	*#Meters to be Installed*	*#Meters Installed to Date*	*Peak Demand Saving Goal – MW*	*Peak Demand Savings Achieved - MW*
SCE	12,000	8,410	292	215
EMeter/PG&E	5,900	4,509	146	118
SDG&E	1,380	1,254	33	30
LADWP	3,418	2,033	107	65
SMUD	300	50	15	2
SCPPA	274	166	7	5
NCPA	70	0	1	0
Totals	**23,342**	**16,422**	**601**	**435**

By June 2002, the program is expected to exceed the original 500 MW goal determined at program startup. The stated MW savings estimates are primarily a result of migration of customers from general service demand rates to TOU, and customer participation in utility voluntary demand response, curtailable/interruptible rate or demand bidding programs.

With the exception of about 200 meters, all meter installations will be completed by June 1, 2002. The remaining meters are located in extremely challenging sites where unexpected physical limitations or paging/cellular/telephone communications coverage problems prevent the utility from easily and cost-effectively providing installations. Fortunately, these sites comprise less than 1% of the total meter population. Solutions, typically radio frequency communications, are being sought, and utility contractors are expected to complete installation of these meters by May 2003.

Meter Installation Verification

Because of the large expenditure , the program will probably be subject to an audit by the State Bureau of Audits. In anticipation of this, a meter installation verification protocol was established to provide documentation for audit purposes. A 1% sample of the 23,342 meters installed under the program was randomly selected by the Energy Commission for meter installation verification. The selections attempted to be as representative as possible of the different business types receiving a meter, as well as being geographically representative of each utility's service territory. Sites were selected based upon Standard Industrial Classification (SIC) codes, postal zip code, and customer size by peak electric demand. Access to selected customer sites were then arranged in advance of the visits by each utility. A representative from the Energy Commission (see Figure 4 below) was sent to meet with the utility and physically verify meter installation and communications system operation at the sites.

Figure 4: Energy Commission Staff Member Verifies Meter Installation and Operation at Customer Site

At each utility office immediately prior to going into the field, Customer Information Sheets (CIS) for each randomly selected customer were generated from the utility's billing system and were printed out for use in the field by the Energy Commission representative. These sheets consist of the customer's name, account number, physical address, meter location, meter number, site contact name, telephone number, assigned rate, most recent reads of on peak, shoulder peak and off peak kWh, kW, kVAR, power factor, and billing cycle. The customer's data display was then accessed over the Internet to verify that they have access to their energy and demand use profiles and to compare and verify the data shown on the display to that shown on the CIS. Accompanied by a utility representative, the meter sites were then accessed to verify that the meter number shown on the CIS matched that of meter actually installed in the meter socket and to verify that the data from the meter display correlated with that given on the CIS.

After completing physical verification, the Energy Commission representative annotated, signed and dated each CIS. Since these sheets contained confidential customer information, they remained behind with the utility to include in their records as documentation of the verification visits. To maintain customer anonymity, the only information retained by the Energy Commission from the site visits were meter numbers, postal zip codes, and SIC codes. Meter installation verification activities are expected to continue through June 2003. A listing of the meter sites verified to date by utility, postal zip code, and legislative district is provided in Appendix E of this report.

Thus far, no irregularities have been found and it appears that all of the utilities have provided meters to customers as required by the contract and that the meters and communications systems are fully operational.

Program Measurement and Evaluation

AB 29X mandated the Energy Commission provide real-time meters, but did not direct how to measure and evaluate the implementation method. The Energy Commission, however, believed that it would be advantageous to evaluate the implementation of the Real Time Metering Program and how it impacted the installed meters on customers' electric demand (kW) and energy consumption (kWh). The Energy Commission directed that an independent measurement and evaluation of the Real Time Metering Program be conducted.

The primary objective of evaluating the implementation process is to report lessons learned about the metering technologies, the installation process itself, and the communication of information to customers. The primary objective of the evaluation is to quantitatively report how the meters and CPUC-required migration to a mandatory TOU rate, affected customer energy usage patterns and how the information made available by the meters was used by customers to make changes to their end-use operations to effect energy savings. The Scope of Work for the evaluation effort is incorporated as Appendix F of this report. Work is currently underway and the Final Report on implementation evaluation is due November 2002. The Final Report on the analysis of the impact of the Real Time Metering Program on customer use patterns for the summer of 2002 is due March 2003. The report for summer 2003 is due April 2004.

Appendix A

Governor Gray Davis Executive Order D-34-01

To view the Executive Order, please use the following link:

http://www.ca.gov/state/govsite/gov_htmlprint

Appendix B

Contract Work Statement Exhibit A

EXHIBIT A
PROPOSED WORK STATEMENT

Contract Objective:

[COMPANY] hereafter referred to as 'contractor' will acquire and install advanced interval metering and related metering communication and end-user information / notification systems necessary to support real-time pricing rate designs and other demand responsiveness options on all end-user accounts with peak demands equal to or exceeding 200kW.

The system plan will include but not necessarily limited to each of the following:

1 CPUC approved, Direct Access compatible, billing quality interval meters,
2 Communication links to each meter capable of remotely collecting end-user usage data no less than once during each 24 hour period,
3 Either meter integrated pulse initiating hardware and software or recommendations for acceptable ancillary hardware and software that can be used either by the [COMPANY]or acquired and used by individual end-users at their own expense to directly access their own metered usage data at intervals more frequently than once during each 24 hour period,
4 Access to a centralized web portal or other information system that can provide individual targeted end-users with timely graphical and/or tabular energy usage and other information regarding their own facilities as well as pricing, electrical system resource status and other system notices and information.
5 A priority implementation plan that assigns:
    5.1 Highest implementation priority to end-users that have already volunteered for or are awaiting participation in existing demand responsive programs
    5.2 Remaining implementation priority to end-users based on peak demand, where the largest end-users receive the highest priority.
6 Contractor will also provide each end-user, at the time of meter installation, with the following:
    6.1 Information on all applicable demand responsive and conservation programs that either require or make use of interval metering capabilities. At a minimum, this notification will include information and the prospective costs and benefits of participating in CPUC approved utility curtailable/interruptible rate options, the California ISO Demand Relief and other related programs, the 20/20 conservation program and all other applicable California Energy Commission sponsored demand responsiveness programs.
    6.2 Training on the use of the metering and end-user information systems.

Defined Terms

Advanced Metering - CPUC approved, Direct Access compatible and billing quality interval metering devices that include communication capabilities necessary to access and retrieve end-user usage information.

Commission - California Energy Commission.

CPUC - California Public Utilities Commission.

End-user Information System - Software to be installed under this contract that provides end-users with periodic or on-demand graphic and tabular information on their facility energy usage levels, usage patterns and accompanying information regarding electrical system hourly prices and appropriate notification regarding system resource conditions, pending curtailments and/or outages.

End-user Target Population - all retail end-users with peak demands greater than 200kW.

Curtailment Program - Programs which Participating End-users may be enrolled in, including but not limited to, the CAISO 2001 Demand Relief Program or similar programs provided by utilities, regulatory agencies and other similar entities.

Demand Responsiveness System - Software and Hardware to be installed under this Contract in order to facilitate end-user load reduction consistent with the Work Statement (Exhibit A).

Participating End-user - Any end-user of a California investor owned or municipal electric utility with a peak demand equal to or greater than 200kW.

Real-Time Pricing (RTP) - An energy rate that provides the end-user, at least daily, with hourly prices that reflect actual wholesale market costs or a proxy for wholesale hourly market costs.

TASK 1 DEVELOP PROJECT PLAN

Objective:

Develop an overall project plan that includes the acquisition, installation and testing of advanced metering, communication and related end-user information systems as well as ancillary systems necessary to collect, store and prepare billing ready data on all end-users with peak demands equal to or exceeding 200kW.

The contractor project plan will include an implementation schedule, budget and end-user training recommendations. Specifically, the contractor will:

1.1. Contractor will identify the number of end-users to receive metering, communication and/or end-user information system resources and the implementation requirements for the end-user target population

1.2. Identify the key contractor, vendor and other resources that will be utilized in each phase of the implementation effort.

1.3. Identify potential resource constraints, regulatory barriers and other factors that may delay or adversely impact the proposed implementation schedule and where possible, the options that contractor will pursue to mitigate implementation delays.

1.4. Identify the available demand responsiveness programs and other demand management resources that, in conjunction with the implementation of advanced metering and the related information systems, will provide or assist end-users in reducing their peak electricity loads and or overall electricity use.

1.5. Describe the marketing materials and methods that will be used or developed to educate end-users regarding the options identified in Task 1.3.

1.6. Prepare a Project Plan that includes the following components:

- 1.6.1. an implementation schedule that identifies all of the tasks necessary to acquire, install, test and manage the required metering and communication equipment within 120 days from contract initiation.
- 1.6.2. a end-user training / education recommendations, and
- 1.6.3. a project budget that identifies meter hardware, communication system, installation, on-going operating and maintenance, data processing (to prepare billing ready data), and end-user related costs on an aggregate and per-meter basis. Costs will be further disaggregated to separately identify anticipated CEC, contractor and end-user contributions. Costs will also separately identify one-time installation versus on-going operating and maintenance.

1.7. The contractor will submit a draft of the project plan to the CEC contract manager for comments and suggested changes. The CEC Contract Manager will provide comments back within 3 business days of receipt. The contractor will then discuss the comments with the CEC contract manager and incorporate the comments into a Final Project Plan.

1.8. Revise the Project Plan prepared in Task 1.5 and prepare a Final Project Plan.

Deliverables:

1. Draft Project Plan and
2. Final Project Plan.

TASK 2 ACQUIRE METERING, COMMUNICATION, INFORMATION SYSTEM AND OTHER RESOURCES NECESSARY TO SUPPORT THE PROJECT PLAN.

Objective:
Acquire the interval metering, communications, meter data management, end-user information systems and other resources necessary to support implementation for the target end-user population.

2.1. The contractor will though competitive solicitation, prior or existing contractual relationships or other means acquire the hardware, systems and implementation assistance necessary to complete the Project Plan.
2.2. The contractor will provide the CEC Contract Manager with a memo report summarizing the work accomplished in Task 2.1. This report will identify the suppliers, resources and contractual relationships established to implement the Project Plan.

Deliverable: Resource Status Memo.

TASK 3: INSTALL AND TEST ALL METERING, COMMUNICATION AND INFORMATION SYSTEMS

Objective:
Install, test and make operational all metering, communication and information systems identified in the Project Plan.

Contractor shall ensure that all system hardware and software has an adequate warranty against defects and is fit for the purpose for which it is designed. The Contractor shall also ensure that adequate service is provided for system operation during summer 2001, including without limitation: maintenance, repair, emergency or on-call service, end-user support, and system updates.

3.1 The contractor will coordinate with the target end-users to schedule the installation of all meter, communication and other related hardware and software necessary to support the Project Plan.
3.2 Conduct all required meter acceptance and communication tests.
3.3 Contractor will submit a bi-weekly summary installation report which provides. This report will identify the number of completed installations (hardware and systems installed and end-user training completed), installations in progress, and installations remaining to complete the Project Plan

Deliverable: Bi-weekly Installation Reports.

TASK 4: TRAIN END-USERS

Objective:
Train / educate end-users as meters are installed regarding the operational features of the metering, communication and information systems installed at their site and provide information regarding hardware and information options that can further support their facility operational objectives.

4.1. Contractor will develop a end-user training plan and educational materials that provides end-users, at the time of installation, with basic information regarding the operation and capability of the installed metering, communication and information systems. A copy of the training plan and educational materials will be provided to the CEC Project Manager.

4.2. Contractor will also provide each end-user, also at the time of meter installation, with information on all currently applicable demand responsive and conservation programs that either require or make use of interval metering capabilities. At a minimum, this notification will include the prospective costs and benefits of participating in CPUC approved utility curtailable/interruptible rate options, the California ISO Demand Relief and other related programs, 20/20 conservation program and all other applicable California Energy Commission sponsored demand responsiveness programs. Contractor will also provide information that identifies who end-users can contact and/or how end-users can participate in these programs.

Deliverable: End-user Training Plan

TASK 5: PROJECT REPORTING

Objective:
Provide the California Energy Commission and Governor's office with a Monthly Progress Report to identify the actual implementation status of the Project Plan.

5.1 The contractor will prepare a Monthly Progress Reports in a format agreed upon by the CEC Contract Manager and contractor. The Monthly Progress Report will supplement the Bi-Weekly Installation Report specified in Task 3.3.. This report will:

- 5.1.1 identify significant accomplishments not previously reported and highlight critical issues requiring the attention of the CEC Contract Manager.
- 5.1.2 provide an updated budget and implementation schedule, and
- 5.1.3 provide information that identifies end-user participation levels in the demand responsive, rate and other programs identified in Task 4.2.

5.2 The Monthly Progress Report will be submitted within five business days following the start of each month until implementation is complete.

Deliverables: Monthly progress reports

TASK 7 FINAL REPORT

Objective:
Bring the project to conclusion.

7.1 The contractor will prepare a final report (in a format previously agreed upon by the CEC Contract Manager). summarizing the highlights and accomplishments of the project. This report will provide a summary of metering and other system implementation activity and provide a final accounting of contract costs.

Deliverable- Final report

Appendix C

Sample Monthly Utility Progress Report

SOUTHERN CALIFORNIA EDISON

An EDISON INTERNATIONAL[SM] Company

REAL-TIME ENERGY METERING PROGRAM

Monthly Progress Report

Prepared for:	California Energy Commission 1516 9th Street, MS 22 Sacramento, CA 95814	
	Contact:	Don Kazama
	Telephone:	(916) 654-5072
	Email:	dkazama@energy.state.ca.us
Prepared by:	Southern California Edison Company 2131 Walnut Grove, 2nd Floor Rosemead, CA 91771	
	Contact:	John Purcell
	Telephone:	(626) 302-4290
	Email:	john.purcell@sce.com

May 7, 2002

Appendix D

Utility Real Time Metering Program Home Pages

To view home pages for each utility contractor's real time metering program, please use the following links:

Southern California Edison: http://www.sce.com/sc3/010_bus_sols

Pacific Gas and Electric: http://www.pge.com/

San Diego Gas and Electric: http://www.sdge.com/business/drp.html

Los Angeles Department of Water and Power: http://www.ladwp.com

Sacramento Municipal Utility District: http://www.smud.org

Southern California Public Power Authority: http://www.scppa.org

Northern California Power Agency: http://www.ncpa.com

Appendix E

Metering Site Verification

Meter Sites Verified

Utility	Meter No.	City Location	Zip Code
Southern California Edison	V349E-003569	Whittier	90601
	V349E-000927	El Monte	91733
	V349E-002340	S. El Monte	91733
	V349E-004491	El Monte	91731
	V349E-002521	West Covina	91790
	V349E-002522	West Covina	91790
	V349E-002523	West Covina	91790
eMeter/PG&E	KRG5634753	San Francisco	94107
	NRG1144204	San Francisco	94108
	LRG4745115	San Francisco	94105
	MRG0913801	San Francisco	94103
	SRG0228292	San Francisco	94109
	LRG5052606	San Francisco	94105
San Diego Gas & Electric	1707641	San Diego	92123
	1362559	San Diego	92105
	1702257	San Diego	92123
	1665845	San Diego	92127
	1706562	San Diego	92101
	1667534	Rancho Bernardo	92129
	1701671	Poway	92064
	1701738	Poway	92064
	1682665	San Diego	92101
	1713846	San Diego	92127
	1362557	San Diego	92110
Los Angeles Dept. Water & Power	1811	Los Angeles	90012
	20365	Los Angeles	90012
	270	Los Angeles	90012
	978	Los Angeles	90012
	73	Los Angeles	90012
	74	Los Angeles	90012
	1955	Los Angeles	90008
	2045	Los Angeles	90012
	914	Los Angeles	90013
	2363	Los Angeles	90004
	929	Los Angeles	90012
	2342	Los Angeles	90012
	299	Los Angeles	90015
Sacramento Municipal Utility District	TBA		
Southern Calif. Public Power Authority	TBA		
Northern Calif. Power Agency	TBA		

Appendix F

Measurement and Evaluation Contract

EXHIBIT A
Scope of Work

background

In March of 2001, the California Assembly (in AB29X) provided $35 million to the California Energy Commission (CEC) for the purpose of installing advanced Automatic Meter Reading (AMR) interval meters, and related communication and end-user information/notification systems. The stated justification for this action was to support real-time pricing rate designs, influence customer electricity end-use patterns, and allow participation in other demand responsiveness options for customer end-user accounts with peak demands greater than 200kW.

As of March 18, 2002, approximately two-thirds of the expected 23,342 meters have been installed at customer sites across the state. At the time of installation, customers who did not face a time-of-use (TOU) tariff were converted to TOU prices by order of California Public Utilities Commission (CPUC) Decision 01-08-021 (ALJ Walwyn) on August 2, 2001. Customers were provided a package of information by their respective serving utility, about accessing a web site to obtain timely information on their metered electricity consumption and methods for taking advantage of that information. They were also provided information about participating in one of the demand response programs offered by their utility or the California Independent System Operator (ISO).

purpose

The objective of this project is to conduct an evaluation of the Real Time Electric Meter (RTEM) program. The evaluation will consist of two parts. One is an *evaluation of the implementation process*, with a primary objective being to report lessons learned about the metering technologies, the installation process, and the communication of information to customers. The other is a *quantitative evaluation* of any changes in customers' demand and energy consumption that can be attributed to the installation of the meters and/or the conversion to new TOU price structures in the absence, currently, of a real-time price tariff for California IOU's.

Task 1. Define project objectives

The contractor will attend a kickoff meeting with the CEC contract manager to discuss and refine the objectives of the evaluation project, the types of information desired, and strategies for requesting and assembling load and customer data from utilities. The primary objectives include, but are not limited to: 1) developing lessons learned about the metering technologies, the installation process, and the communication of information to customers, and 2) estimating the effect that the installation of hourly metering and the possible conversion to TOU pricing has had on customers' demand and energy consumption. As part of the kickoff meeting, the contractor and contract manager will discuss the types of research questions that are most important to address in the project.

Deliverable: Project kickoff meeting
Schedule: Before April 19, 2002

Task 2. Develop research questions

The contractor will develop a list of specific, answerable research questions that need to be addressed in the evaluation project. The research questions will deal with the two main evaluation areas, the implementation process and the impact of the meters on demand and energy consumption. Examples of the types of research questions that may be developed include the following:

Implementation evaluation

What technical problems, if any, were encountered in the design of the metering devices, and the data collection and storage processes for each of the utilities?
What problems or barriers were encountered in the meter installation process?
What were customers' perceptions of the meter installation process?
How useful did various types of customers find the educational materials provided by the utilities after the meters were installed?
How useful and easy to use did customers find the web site?
How frequently did they access their usage information?

Impact evaluation

What can be inferred about the effect of the meter installation program on customers' electricity demand (kW) and energy consumption (kWh), particularly distinguished by time period?
How much of this effect can be attributed to factors such as the timely information available to customers on their energy usage pattern, and the conversion to TOU pricing?

The contractor will prepare a draft report including the list of research questions developed for approval by the contract manager. Upon approval, the Contractor will submit a final Research Questions report to the Contract Manager.

Deliverable: Draft Research Questions report Date due: 5 business days after the kickoff meeting
Deliverable: Final Research Questions report Date due: 3 business days following contract manager approval

Task 3. Develop data collection and analysis plan

In this task the contractor will develop a detailed plan for collecting and analyzing the data needed to answer the research questions developed in Task 2. The plan will identify two categories of data – data on customer characteristics and metered usage data available in principle from the utilities; and data to be developed in the project through interviews and/or surveys.

The contractor will consult with the contract manager to determine the most effective means of requesting and obtaining customer and metered load data from the investor-owned and publicly owned utilities. The contractor may, subject to approval by the contract manager, work with other entities, including investor-owned and municipal California utilities, to have data not available to the CEC delivered directly to the Contractor under a strict confidentiality agreement between the parties supplying the data and the contractor. The contractor will develop an analysis plan describing the type of statistical and econometric analyses to be undertaken once the data have been received in order to address the research questions in Task 2.

The contractor will develop a plan for collecting the interview and survey data needed to inform the implementation portion of the evaluation. This will include indicating interview candidates, developing a plan for scheduling them, and preparing a sampling plan for the surveys. The method of selecting a sample may depend on some of the above data issues. For example, the contractor may have to work with individual utilities to have them select samples of customers from the population of customers with the hourly meters installed, based on guidelines that the contractor provide. On an ongoing basis as these these plans are developed, the contractor will submit them for review and approval by the contract manager.

Deliverable: Data collection and analysis plan report.
Schedule: 15 business days after Final Research Questions Report.

Task 4. Analyze preliminary data to refine data collection needs

At the present time, there is some uncertainty about the type of customer and load data that the utilities will make available for this project. The contractor will analyze the preliminary data that the CEC receives from the utilities. These data will be aggregated by customer type and geographical location. The contractor will assess the ability to measure load changes and attribute them to the meter installation using the available data, and will report the results of that analysis to the contract manager. The contractor and contract manager will meet in person or by telephone to discuss possible refinements to the analysis techniques and data collection plan to successfully evaluate the effect of the meter installation, given the usefulness of the preliminary data.. The contractor will submit a draft report to the contract manager for approval that includes a revised schedule for additional data collection, analysis, and reporting for the remainder of the evaluation project. Upon approval, the contract manager will submit a final report to the contract manager.

Deliverable: Preliminary data analysis results report
Schedule: Forty working days following contractor's receipt of the preliminary data
Deliverable: Meeting between contractor and contract manager
Schedule: Within 5 business days of the contractor's receipt of the Preliminary data analysis report
Deliverable: Draft revised data collection, analysis, and reporting plan report
Schedule: Ten business days after contractor and contract manager meeting
Deliverable: Final revised data collection, analysis, and reporting plan report
Schedule: 5 business days after delivery of contract manager's review

Task 5. Conduct interviews and surveys

The contractor will conduct the interviews and surveys described in the Data Collection and Analysis Plan Report.

Sub-task 5.1. Interviews

The contractor shall arrange and conduct interviews with key individuals at a number of the relevant organizations involved in the meter installation program, as described in the Data Collection and Analysis Plan Report. The contractor shall develop interview guides and submit them to the contract manager for approval. The contractor shall arrange and conduct the interviews following the interview guides developed as part of the Data Collection and Analysis Plan Report.

Deliverable: Draft report, summarizing interviews, to serve as input to the process evaluation report.

Schedule:	June 30, 2002.

Sub-task 5.2: Survey

The contractor will use the data collected through the interview process to develop additional quantitative information to inform the implementation process evaluation. The contractor will develop information for use in improving the load data analysis, and in making decisions about future rate designs and customer end-use technology programs. This information will be reported in the Survey Results Report, and detailed in the Final Project Report.

The contractor shall design and implement a series of data collection activities, subject to prior approval by the contract manager. The survey implementation will include designing the survey instrument, having it reviewed and approved by the contract manager, designing appropriate samples, conducting survey pre-tests, and then implementing the surveys. The resulting data will be assembled in databases for analysis. Once the data have been collected, the contractor shall conduct standard statistical tabulations and analyses to summarize the survey responses. These tabulations and analyses will be included in the Survey Results Report.

The contractor shall use generally accepted screening techniques to identify up to 1200 energy managers across the utility service areas. The contractor shall perform a telephone screening to identify the most appropriate individual, such as an energy manager, to participate in the survey. The telephone call will be made to the individual listed as the contact person for the meter installation. Once this person has been reached, he/she will be asked to identify the person in the company that would be able to discuss the company's reaction to the meter. The contractor shall then contact this person and recruit him/her to complete the survey. Subject to the contract manager's approval of research design and methodology, the contractor will pre-test the survey procedures and draft survey on a small sample of energy managers. Results from this pre-test will be used to make final revisions to survey procedures, sample design, and survey instruments. These revisions will be subject to approval by the contract manager. The

If a web-bsed survey method is approved by the contract manager, the contractor will provide a key and a URL at which the form can be accessed to those agreeing to complete the on-line survey. The key and the URL will be provided verbally during the phone call, but the contractor will also ask the potential respondent to provide an e-mail address so that the contractor can provide the key and URL by e-mail. The e-mail address will also be used to thank respondents completing the form and to make additional reminder contacts with respondents not completing the form within a specified time period.

**Deliverable:	Draft sampling plan	Schedule: June 1, 2002**
Deliverable:	Final sampling plan	date
Deliverable:	Draft survey implementation plan	Schedule: June 1, 2002
Deliverable:	Final survey implmentation plan	date
Deliverable:	Draft survey results	Schedule: September 15, 2002

Task 6. Collect and analyze installation and program information

The contractor shall collect and review of all relevant meter installation program information needed to evaluate the installation process and analyze the information in order to characterize the context in which the program was implemented, including agreements between the CEC and meter installation entities and their sub-contractors, barriers imposed by law, time frame, and coordination with installation contractors. The contractor shall describe issues regarding physical and institutional barriers to installation. The contractor shall develop a timeline for the meter installation project, including administrative actions and statistics on the timing of installation. For inclusion in the program information report, results will be aggregated to the entire program, but also provided by contractor and region, including details useful in understanding installation patterns. Contractor will summarize results of this work in a Draft Review of Program Information Report, subject to review and approval of the contract manager. The final version of the report will be included in the Final Project Report.

Deliverable: Draft review of program information report Schedule: July 31, 2002

Task 7. Collect metered load data

The contractor will conduct a data collection in two phases. Phase 1 will involve collecting load data through summer 2002. Phase 2 will involve collecting data through summer 2003. After receiving the data, the contractor shall assemble analysis databases in preparation for conducting the quantitative analysis. The contractor will provide, subject to approval by the contract manager, a Load Data Report consisting of datasets and/or summary statistics on the dataset prepared using the collected data, subject to requirements of confidentiality agreements entered into by the contractor or the CEC to obtain metered load data.

Deliverable: Load Data Report
Schedule: Phase 1 – November 30, 2002
Phase 2 – November 30, 2003

Task 8. Load data analysis

The contractor shall conduct a series of analyses using the customer load data, designed to measure changes in customer usage patterns due to the real-time energy meters. The analyses will include descriptive statistical comparison of loads for different groups of customers, as well as econometric demand modeling designed to measure the separate effects of factors such as the meter installation alone, changes in price structure, presence of energy-saving incentive programs such as the 20/20 program, and others. The analysis will be undertaken in two phases, corresponding to the data collected and assembled in preparation for the Load Data Report. .

The contractor will, to the extent deemed necessary and subject to approval by the contract manager, also use the data and analysis results to simulate the effect of potential alternative tariff designs on customer electricity use. The contractor shall work with the contract manager to convert the analysis results into a form most useful for the CEC Demand Forecasting model.

Deliverables: Reports describing analysis of load data.
Schedule: Phase 1 – February 2003
Phase 2 – February 2004

Task 9. Reporting

This task includes both monthly reports on project status to the CEC project manager, and draft and final reports on project results. The contractor shall produce a draft and revised final report that summarizes the installation process evaluation, and two sets of draft and revised final reports that document the impact evaluations for summer 2002 and 2003. These reports will compile the reports provided as deliverables in the tasks. The reports will respond to the research questions developed in the Final Research Questions report, and will provide text and graphical representations of results. The contractor shall also work with the CEC project manager to develop appropriate appendices that provide detailed information on data and analysis results.

Deliverables:	*Dates:*
Monthly reports	Monthly
Report on implementation evaluation	
Draft	October 31, 2002
Final	2 weeks after comments received by contractor
Report on summer 2002 analysis	
Draft	February 28, 2003
Final	2 weeks after comments received by contractor
Report on summer 2003 analysis	
Draft	March 31, 2004
Final	2 weeks after comments received by contractor