Application No.: ____________________

Exhibit No.: SCE-3

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TESTIMONY SUPPORTING APPLICATION FOR APPROVAL OF ADVANCED METERING INFRASTRUCTURE PRE-DEPLOYMENT ACTIVITIES AND COST RECOVERY MECHANISM

Volume 3 – AMI Preliminary Cost Benefit Analysis

Before the

Public Utilities Commission of the State of California

Rosemead, California

December 21, 2006

LAW-#1320693

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I.

INTRODUCTION

The purpose of this volume is to describe SCE's preliminary cost benefit analysis for the entire AMI project. SCE recognizes that a preliminary cost benefit analysis of the entire AMI project is a necessary component to allow the Commission to determine that the Phase II funding request is reasonable. This preliminary cost benefit analysis provides a reasonable level of assurance that AMI (over the full life of the project) produces customer benefits in excess of the project costs. In fact, on a present value revenue requirement basis, the AMI project is expected to produce customer benefits of over $106 million, and is a significant improvement over SCE's earlier cost benefit analysis performed in March 2005.[1]

Section II of this volume provides a detailed discussion of the preliminary cost benefit analysis. In this section, the results of the cost-benefit analysis are summarized and the analytical approach is described. This section also describes all the associated costs and benefits for SCE's AMI proposal over the entire life of the project and shows that the result of the cost benefit analysis is indeed positive for customers on a present value revenue requirement basis.

In Section III, an analysis of the AMI revenue requirement and the expected customer impacts is presented. This analysis is important in that it measures the benefits and costs from a customer perspective so that SCE can determine the expected revenue requirement impacts customers would incur or avoid. This analysis shows that the AMI project over its entire life is expected to result in customer benefits of $106 million in excess of the costs. Thus, from a customer perspective, it is reasonable to proceed with Phase II of this project.

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[1] *See* A.05-03-026.

II.

PRELIMINARY COST BENEFIT ANALYSIS

A. Summary of Results

Beginning in April 2006, SCE undertook a complete revision of its benefit and cost estimates incorporating the added functionality of the new metering and telecommunication system capabilities. The Phase I Use Case results provided new insights and a more comprehensive approach for identifying and estimating costs and the value of benefits. In addition, the comprehensive market assessment conducted as part of Phase I activities provided new insights with regard to functional capabilities, product reliability and estimated cost. As a result, SCE was able to add significant benefits while reducing the level of uncertainty accompanying its earlier cost estimates. Though the cost-benefit analysis process is comprehensive, the results are still considered "preliminary" primarily because there remains much to be learned. Midway through Phase II, SCE expects to re-visit the cost-benefit analysis to incorporate the results of the Requests for Proposals (RFPs) issued in December 2006, and will continue the development of time-of-use and critical peak pricing tariffs. A final financial assessment that incorporates SCE's final technology selections and vendor pricing will be developed for internal management review and as support for SCE's AMI Phase III full deployment application that SCE expects to file with the Commission in mid-2007.

Though preliminary, SCE considers this latest update reasonable, and has included contingency costs estimated to reflect the risk factors still accompanying several key cost areas. Through the early stages of Phase II, new information will be obtained relating to firm bids resulting from RFP responses and the technical results of component testing of the first production models of metering and communication products. It is also possible the added functionality of the new meters will result in new, unforeseen opportunities for potential benefits. Thus, SCE is confident that any revisions to the present estimates are likely to reduce estimated costs and/or increase benefits, resulting in a continued positive case for AMI.

Results of SCE's preliminary cost benefit analysis are presented in Table II-1 below, and are described in more detail in the following sections.

Table II-1
Preliminary Cost Benefit Analysis Results
($Nominal and 2007 Present Value of Revenue Requirement, in Millions)

	Nominal	2007 PVRR
Benefits		
Meter Services Operations	$2,988	
Billing	512	
Call Center	98	
TDBU Operations	102	
Demand Response – Price Response	1594	
Demand Response - Load Control	882	
Other	380	
Total Benefits	**6,556**	**$1,854**
Costs		
Infrastructure Procurement	1,190	
IT Systems Development and Integration	273	
AMI Infrastructure Installation and Deployment	213	
Customer Tariffs, Programs and Services	346	
AMI Program Management and Contingency	177	
Phase II Costs	67	
Post-deployment Steady-state Incremental Operating Costs	497	
Total Costs	**2,763**	**1,748**
Net Nominal Benefits	**$3,793**	
Net Present Value of Revenue Requirement		**$106**

B. Analytical Methodology

SCE's cost benefit analysis is a financial comparison of the present value of estimated AMI costs and benefits over the useful life of the AMI system. Cost and benefit estimates were derived through an intense internal process involving the participation of all affected SCE operating departments. Estimated costs and benefits were applied to the proposed deployment schedule, incorporating annual meter growth and cost escalation factors over the 26 year analysis period starting on January 1, 2007 and concluding on December 31, 2032. The analysis includes all proposed Phase II pre-deployment costs (the subject of this application), all estimated deployment costs (the subject of SCE's full-deployment application to be filed mid- 2007) and all estimated post-deployment "steady-state" incremental costs resulting from AMI (to be recovered through future cost of service proceedings).

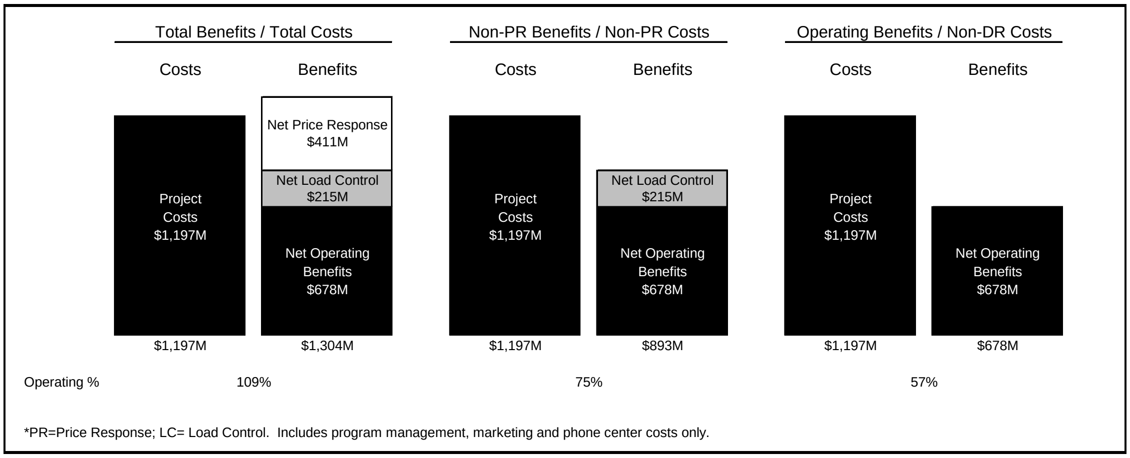
The analysis period is dictated by the multi-year deployment schedule that begins in 2009, and by the 20-year useful life of the meters. To capture the full useful life of meters installed in the last year of deployment (2012), the analysis extends to 2032. However, SCE recognizes that the initial installed AMI meters would be more than 20 years old by that time, so the model includes a substantial increase in assumed meter failures (and associated costs) as each "vintage" of meters reaches its 20-year service life in 2029, 2030, 2031, and 2032.

Annual costs are escalated for inflation and stated in terms of nominal dollars. In Section III of this volume the same costs and benefits are assessed in terms of Present Value of Revenue Requirement (PVRR), which provides the customer impacts over the life of the project.

C. Operational Cost Benefit Ratio

For the AMI project, a benefit-to-cost ratio based on the total net preliminary project benefits and total preliminary deployment costs (expressed on a 2007 PVRR basis) of 109 percent is produced. In other AMI proceedings before the Commission, comparisons have been made among the utilities based strictly on the ratio of operational benefits as a percent of total AMI project costs. As such, SCE has calculated the ratio of total net operational benefits, reflecting no demand response benefits or costs, to total project costs, which produces a benefit to cost ratio of 57 percent. However, given the significance of direct load control as enabled in SCE's AMI program, a better approach that reflects firm benefits based on SCE's experience would be to include direct load control-related costs and benefits in the calculation of the ratio. The analysis of operational plus direct load control benefits to respective cost results in a benefit-cost ratio of 75 percent. Each of these benefit-to-cost ratios is illustrated in Figure II-1.

Figure II-1
Comparison of 2007 PVRR Benefit-to-Cost Ratios for AMI Project
($ millions)



As the Commission is aware, this operational cost-benefit ratio can vary significantly from one utility to another given the operational efficiency starting point for the evaluation. In SCE's case, one reason for a lower operational cost ratio in the simple calculation is the fact that SCE has already installed over 600,000 automatically read meters in its most costly meter routes, thus reducing the incremental benefit to be derived from automatic meter reading. Additionally, SCE has invested in one of the largest distribution automation systems in the industry that reduces one of the potential benefits from advanced metering.

D. Description of Cost Estimates

AMI project cost estimates are addressed in six general cost categories:

- **Infrastructure Procurement costs** incurred in the pre-deployment, deployment, and post-deployment periods. This includes vendor management and metering and telecommunications network procurement costs, but does not include installation costs.
- **IT Systems Development and Integration** costs, including procurement, development and integration of the Meter Data Management System (MDMS), and the Data Center Aggregator (DCA) System.

- **AMI Deployment and Infrastructure Installation** costs, including supply chain management and logistics related to installing the AMI metering and telecommunications infrastructure in the field.
- **Customer Tariffs, Programs and Services** costs, including all demand response program operational costs incurred throughout all three deployment periods.
- **AMI Program Management Organization (PMO)** costs**,** including business process and organizational readiness costs, as well as project administration and quality assurance costs.
- **Post-deployment Steady-state Incremental Operating** costs**,** which include on-going capital and O&M costs in the post-deployment period that are incremental to AMI, exclusive of Customer Tariffs, Programs and Services costs.

The following sections describe the activities, assumptions and cost estimates for each of the above cost categories. All costs are incremental as a result of AMI and do not include any SCE operating and maintenance (O&M) costs or capital costs that would have otherwise been incurred. Any costs that may be displaced or deferred as a result of AMI are included as a cost avoidance benefit attributed to AMI and will be discussed in the section on estimated benefits.

1. Infrastructure Procurement Costs

a) Category Description

Infrastructure Procurement costs include the systems engineering and design activities, vendor relations, metering and telecommunications network procurement costs, and product testing costs incurred in the pre-deployment and deployment periods. This includes both capital costs as well as O&M costs. SCE's AMI Product Management group was responsible for the technical development, engineering and design activities in Phase I and will be responsible for seeing that SCE's design requirements are met throughout the procurement and deployment stages of the AMI project. They will meet this responsibility by overseeing the procurement process and by conducting the quality control functions necessary to assure that SCE's requirements are actually being met by the vendors.

b) Summary of the Infrastructure Procurement Cost Estimate

The major components of SCE's Infrastructure Procurement Costs are shown in Table II-2. These costs will be incurred in the pre-deployment period (Phase II) and the deployment period (Phase III) and will include metering and telecommunications infrastructure costs and the cost of providing the technical oversight and quality control processes necessary to assure all AMI technical design requirements are met. The majority of these costs will be incurred during the deployment process (ending approximately June, 2012). However, this cost component also includes the procurement of meters for new customer growth and replacement of failed meters throughout the post-deployment period. Once deployment is completed, the technical oversight and quality control functions will continue as on-going steady-state operational costs.

The costs in this category (and all subsequent cost and benefit categories) are expressed in nominal dollars. Annual expenditures were estimated based on the AMI deployment schedule as described in Volumes 1 and 2 of the testimony supporting this application.

Table II-2
Infrastructure Procurement Costs

Cost Component	Nominal ($000)
Meter Engineering & Testing	$7,400
Metering Infrastructure	755,000
Telecommunications	428,000
Total	$1,190,400

c) Business Case Cost Drivers

Essential to SCE's requirements specification is the ability to meet the Commission's functionality requirements as described in Volume 1 of the testimony supporting this application. As stated previously, these six functional requirements are fundamental to the basic design of SCE's AMI system and its integration with SCE's operating systems.

These regulatory requirements relate to the ability of AMI to collect and process 24 hourly meter reads every day, compared to today's need for just one meter read every month. To accomplish this requires metering capabilities far more sophisticated than the typical residential meters that exist today. SCE's metering specification includes not only the data collection and self contained storage capacity to meet the daily read requirement, but also provides adequate storage and alternative meter reading capability providing back-up to assure a minimum data loss and/or contamination thus assuring the accurate billing of TOU and CPP rates. The Commission's data collection requirements drive the cost of SCE's AMI metering and telecommunications infrastructure considerably above what would otherwise be required for simple automated meter reading on a monthly basis. These same data requirements hold great promise for providing significant, long-term cost savings that will result from the more efficient use of electricity by SCE's customers.

Another major cost driver related to SCE's AMI metering infrastructure is the ability to remotely connect and disconnect service to any of the five million SCE customers any time of the day or night. To have this capability integrated (self-contained) within the meter itself adds to the meter cost but is cost effective based on its functional value and is significantly more cost effective than the alternative method of using a separate meter collar appended to the meter. Though not one of the Commissions functionality requirements, the remote connect/ disconnect feature adds significantly to the overall cost effectiveness of AMI.

A third significant cost factor in this category is the expected life of the assets. The longer the asset (*i.e.*, meter) life, the longer the business case term and the longer the benefits can contribute to the business case. SCE's historical AMI business cases have assumed a 15-year useful life for newly installed AMI meters. This useful life was based on a conservative approach to product life absent information from vendors, market and technical analysis. Over the past six months, SCE has received information from vendors, technical literature and product testing results at SCE's Westminster facility indicating that meter useful lives will likely be 20 years or more. This is consistent with regulatory treatment of meter useful lives in California and other regulatory jurisdictions. SCE plans to use a three-pronged approach. First, SCE is requiring meter vendors to design for a 20-year service life. All vendors are designing to the 20-year life specification. Second, SCE is also requesting that the vendors provide engineering analysis and perform accelerated life testing which will provide some assurance that the product is manufactured as designed. Third, SCE is expecting the vendors to provide 20-year limited warranties for their products. Fourth, SCE will be conducting accelerated life testing to confirm vendor results. SCE recently completed accelerated life testing on one solid state simple kilowatt hour meter. The meter went through thermal shock and thermal cycle (-50c to +100c) for 80 days. This translates to well over 20-year life using generally accepted useful life modeling procedures. The result far exceeded SCE’s expectations and is a good indicator that solid state meters have reached a level of maturity that is equal to or greater than the current electromechanical meter.

d) Infrastructure Procurement Cost Assumptions

Infrastructure procurement cost estimates were based on the following assumptions:

- All meters will include two-way communication capability;
- On-demand read capability for daily meter reads;
- Remote connect/disconnect capability built into all residential meters;
- Standards-based communication capability with in-home devices;
- All meters will be remotely configurable;
- 20-year useful life expectancy for all metering components;
- 20-year useful life expectancy for all telecommunication components;
- 3.5 year full scale deployment;
- 100% of <200kw customers receive new meter;
- 100% communications coverage deployed in advance of meter installations;
- One or two telecommunications technologies may be utilized;
- A minimum of two metering technologies will be utilized.

Other more detailed cost assumptions are included in the work papers associated with this chapter.

2. IT Systems Development and Integration

a) Category Description

IT Systems Development and Integration costs include: (1) the development and procurement cost of a new Meter Data Management Systems (MDMS), (2) the implementation and maintenance cost of the AMI telecommunications network systems, (3) development, testing and integration of the Data Center Aggregator (DCA), (4) all Load Control System interfaces and testing, and (5) the Web Portal (sce.com) upgrade cost. These costs include the integration of the MDMS and DCA systems planned to be in production for full AMI deployment. This includes the cost of all billing system integration and testing and the testing of all vendor installation interfaces incurred in the pre-deployment and deployment periods. These costs include both capital and O&M.

b) Summary of the IT Systems Development and Integration Cost Estimate

The major components of the IT Systems Development and Integration Costs are shown in Table II-3. These costs will be incurred in the pre-deployment period (Phase II) and the deployment period (Phase III) and will include IT network and meter data management system design, integration and testing costs. This will also include the cost of providing the technical oversight and quality control processes necessary to assure all AMI technical design requirements are met. By definition, this category includes only Phase II and Phase III costs and will conclude with the completion of the deployment process (approximately June 2012). Once deployment is completed, the IT system maintenance functions will continue as on-going steady-state operational costs.

These costs are expressed in nominal dollars. Annual expenditures were estimated based on the AMI deployment schedule and the IT Systems Development and Integration functions described in Volume 2 of the supporting testimony.

Table II-3
IT Systems Development and Integration Costs

Cost Component	Nominal ($000)
Implement and Maintain Telecom Systems	$117,900
Load Management	9,700
MDMS	100,900
System Management Console	11,000
Web Enhancements	33,200
Total	$272,700

c) Business Case Cost Drivers

Essential to SCE's requirements specification is the ability to meet the Commission's functionality criterion relating to metered data as described previously in Volume 2 of the testimony supporting this application. These regulatory requirements relate to the ability to collect and process 24 hourly reads every day, compared to today's need for just one meter read every month. To accomplish this requires the IT systems capacity and intelligence to access, process and store vast quantities of metered data, several hundred times greater than present day systems are required to handle. Additionally, the Commission's desired functionality requires that all the acquired data be accessible by SCE's customers after the fact. Meeting these data management system requirements is the key driver affecting the IT Systems cost estimates.

SCE's AMI IT Systems Development and Integration processes and vendor market assessment were major components of SCE's *AMI Conceptual Feasibility Report* (Exhibit SCE-4). Through that process, SCE has completed a preliminary evaluation of vendor capabilities in meeting SCE's RFP specification for the MDMS and systems integration functions. Using the results of the preliminary vendor evaluations, SCE has defined the systems architectural requirements included in its MDMS RFP. SCE has established a comprehensive plan to evaluate individual vendor capabilities of meeting those requirements and ultimately deliver a fully tested commercially available MDMS that conforms to SCE's specification. Final determination of SCE’s MDMS and systems integration vendor is a key objective of its Phase II activities as described in Volume 2 of the testimony supporting this application.

The business case dictates the scheduling of each stage of system development and testing that must be accomplished to assure that the benefits to be derived from automatic meter reading and demand response programs are achieved in a timely manner. Adding to the complexity of the regulatory and business case cost considerations is the more practical, operational requirement of keeping the present day systems operating in parallel with the new systems through the deployment stages of AMI.

d) IT Systems Development and Integration Cost Assumptions

The IT Systems Integration cost assumptions include:

- The design, development, procurement and testing of the Data Center Aggregator (DCA) and core back office systems needed to establish two-way system communications with each customer’s premise.
- The AMI IT systems that will access and process the data generated by the AMI meters and any in-home devices supporting AMI enabled programs.
- The integration of all new AMI systems with existing SCE legacy systems as necessary to provide a seamless operational transition of existing business processes to the new automated processes being introduced by AMI.
- The development and implementation of the Meter Data Management System (MDMS) utilizing commercial packaged software.
- The SCE Resources and Consulting support needed to complete the purchase of the MDMS software package.
- The infrastructure hardware installation for the software package.
- The associated upgrades and interfaces to legacy systems.
- AMI security and network management enhancements to the DCA systems needed to meet SCE’s corporate policies and requirements.

3. AMI Infrastructure Installation and Deployment Costs

a) Category Description

The AMI Infrastructure and Deployment Cost category includes all of the costs associated with the physical deployment of the AMI meter. This category includes the costs to procure the meters (not the cost of the meter itself) as well as the costs to warehouse and deliver the meters to the appropriate field locations throughout SCE's service territory. This category also includes the costs for internal and outsourced resources to install the new AMI meters for the duration of the deployment including vehicle expense. The costs for customer communications related to the rollout for the installation of the AMI meter is also included in this category. Such costs involve the development, production and mailing of AMI customer welcome notifications in five languages as well as targeted communications to various customers throughout the service territory to inform them about the AMI rollout schedule in their locale and describe the impacts customers should expect as a result of the AMI deployment. The customer communication cost category also includes the Call Center costs associated with the handling of calls from customers inquiring about the various AMI customer communications or inquiring about the first bill received after the AMI meter is deployed.

b) Summary of the AMI Infrastructure Installation and Deployment Cost Estimate

There are several components that make up the AMI Infrastructure Installation and Deployment costs totaling $212.6 million (nominal dollars). These cost components include customer communications, logistics and procurement, facilities, vehicles and internal meter installation and outsourced meter installation. The largest cost component is the outsourced meter installation which is estimated at $146.6 million (nominal dollars). These costs are shown in Table II-4.

Table II-4
AMI Infrastructure Installation and Deployment Costs

Cost Component	Nominal ($000)
Customer Communications	$15,100
Facilities	2,200
Internal Meter Installation	39,400
Logistics & Procurement	7,600
Outsourced Meter Installation	146,600
Vehicles	1,700
Total	$212,600

c) Business Case Cost Drivers

There are three primary business case drivers for this cost category as shown in Table II-4. These include the outsourced meter installation cost component, the internal meter installation cost component and the customer communications cost component. The largest of these cost drivers is the outsourced meter installation component. This cost component is new, as in the previous business case analysis SCE planned to do all the meter installations with internal resources. The outsourced meter installation of about 4.5 million meters will result in the completion of all meter installations on an accelerated schedule at a lower cost. SCE plans to use internal resources to install about 10% of the existing customer meters and all new customer meter sets for a total of about 15% of all meters installed during the deployment period.

The metering and telecommunications system deployment activities will be outsourced as this deployment activity is a one-time occurrence and there are vendors specifically equipped to perform such activities on a cost effective basis. Outsourcing of these major activities also helps to mitigate program risks. The business case also dictates the scheduling of each stage of installation and testing that must be accomplished so that the benefits to be derived from AMI and demand response programs are achieved in a timely manner. Adding to the complexity of the regulatory and business case cost considerations is the more practical, operational requirement maintaining the present day meter reading and field services functions in parallel with the new systems as each area is transitioned to AMI.

The internal meter installation cost component involves those meters that will be considered complex meter installations. For these complex meter installations, skilled SCE resources are required to safely complete the installations. In addition, this cost component contains the costs associated the meters that the outsourced installers are unable to complete due to issues such as persistent access problems. For those meters, SCE will use internal field resources to complete the installations. The customer communications cost component contains the costs associated with customer communications notifying the affected customer of the meter change-out. These customer AMI notification packages will be produced in five languages.

d) AMI Infrastructure Installation and Deployment Cost Assumptions

The key assumptions for the three primary cost drivers in the AMI Infrastructure and Deployment Cost category include:

Customer Communications. Some customers are expected to contact SCE's call center with questions regarding the AMI meter installation, the AMI notification package or the first bill generated after the AMI meter is installed. Customers will need targeted communications regarding the rollout of AMI and the impacts to them requiring the use of multiple communications channels.

Internal Meter Installations. Approximately 10% of all meters installed during the deployment period will be a complex meter installation that require the technical installation expertise of internal SCE resources or installation that the outsource meter installer is unable to complete due to the inability to access the existing meter. Also, all new customer meter sets during the duration of the program will be done internally.

Outsourced Meter Installations. Approximately 85% of all the AMI meters to be installed throughout the deployment phase by an outsourced meter installer.

4. Customer Tariffs, Programs and Services Costs

a) Category Description

The Customer Tariffs, Programs and Services Costs category contains all the costs for the load control and price response capabilities associated with AMI. This cost category is estimated at $346 million (nominal dollars) and contains the costs for acquiring, installing and maintaining load control equipment such as the SCE smart thermostat (Title 24 compliant) and other load control devices. This cost category also includes processing of customer applications and applicable rebates associated with participation in AMI facilitated load control programs. In addition, this category contains all of the costs for the AB 1X compliant price responsive tariffs (*e.g.*, Time of Use (TOU) and Critical Peak Pricing (CPP)) that will be available as a result of AMI capabilities. The costs for the development and implementation of price responsive tariffs include market research, necessary customer communications such as enrollment notification and CPP event notification, tariff program management support and website management. As part of the AMI Phase II activities, SCE will prepare proposed tariffs and programs that it expects to meet SCE's AMI demand response objectives. These proposed tariffs and programs are described in Volume 2 of the testimony supporting this application.

b) Summary of the Customer Tariffs, Programs and Services Cost Estimate

The costs for this category are shown in Table II-5 and are estimated at $346 million (nominal dollars).

Table II-5
Customer Tariffs, Programs and Services Costs

Cost Component	Nominal ($000)
Load Control	207,500
Price Response	138,400
Total	$345,900

c) Customer Tariffs, Programs and Services Cost Drivers

There are two primary business case cost drivers associated with the Customer Tariffs, Programs and Services cost category as shown in Table II-5. These cost drivers are load control programs and price response tariffs. The load control programs cost component is the larger of the two cost drivers with its largest component consisting of the costs related to enrollment packages and mailings during deployment and customer outreach and education. The other cost driver is the price responsive tariffs cost component. This cost category contains the costs associated with the customer inquiries about enrollment, website management to display real time pricing information, tariff program management costs such as event notification and necessary market research to maximize tariff program participation.

d) Customer Tariffs, Programs and Services Cost Assumptions

The cost assumptions for this category are combined in two components: Price Response Tariffs and Load Control Programs.

The assumptions for the Price Response Tariffs cost component include:

- Customer communications including bill inserts and letters to customers about their rate options once their AMI meter is installed, costs of media marketing and targeted marketing of residential rate choices during AMI initial deployment, and the cost of upgrading SCE's website services to include next-day information about customer usage and applicable tariff rates.

- The AMI system will provide information available to ZigBee compatible information display devices and smart appliances at the premise. The cost of information display devices is not included because it is assumed that devices and appliances will become available for customer purchase.

- Residential and commercial and industrial (C&I) customers below 100kW in demand will be defaulted to a TOU rate when they receive an AMI meter. The assumed sustained enrollments of residential customers on TOU rates are 44 percent on AB 1X compliant rates and 58 percent on non- AB 1X rates. C&I customer enrollment in TOU is assumed to be 58%. Customers will be notified of the rate change and placed automatically on the default rates. Customers may opt out of the default rate via telephone, Internet website or mail.

- Residential and C&I customers below 100kW in demand will voluntarily enroll in CPP-F rates when they receive an AMI meter. Voluntary enrollments may be through mail, Internet website or telephone. When AB 1X is in force, residential CPP enrollment is assumed to be 20 percent (2009 to 2011). After 12/31/2011, CPP enrollment is assumed to be 11 percent.

- C&I customers 100kW and above would be defaulted to a mandatory TOU rate with the option to choose a CPP-F rate. The assumed enrollment is 88 percent TOU and 12 percent CPP-F.

The assumptions for the Load Control Program cost component include:

- Title 24 compliant Programmable Communicating Thermostats (PCTs) will be available and installed in new homes and heating, ventilation and air conditioning (HVAC) retrofits requiring permits beginning in 2009. Since the PCTs are required by code, no equipment or installation costs are included in the AMI analysis.

- SCE will offer and market a load control program to customers with T24 PCTs and AMI meters and 25 percent will enroll. Customers will be paid an incentive to participate.

- An SCE Smart Thermostat program (using Title 24 compliant PCTs) will be offered to residential customers with AMI meters and central air conditioning. This program will replace the existing air conditioning cycling program beginning in 2009 as a more cost effective means of providing new grid reliability benefits as well as peak load reductions from economic dispatch. A marketing program will initially enroll 60,000 customers per year until approximately 250,000 customers are enrolled. Enrollment at 250,000 will be maintained. Costs include PCT equipment and installation. Customers will be paid an incentive to participate.

5. Post-Deployment Steady-State Incremental Operating Costs

a) Category Description

The Post-Deployment Steady-State Incremental Operating costs are those operating expenses that SCE expects to incur on an on-going regular basis once the initial AMI meters are installed. The costs for on-going customer service operations such as billing, call center operations and field services represent over 80 percent of the costs in this category. The steady-state incremental costs also include the costs to work trouble reports for the expected

AMI meter failures after the initial installation and the cost of installing replacement meters. Other significant costs in this category include the incremental costs to address load forecasting complexities involving enhanced real time data available through AMI.

b) Summary of the Post-Deployment Steady-State Incremental Operating Cost Estimate

There are several cost components in this cost category that comprise $496.8 million (nominal dollars) of expected steady-state incremental costs. These cost components include the incremental cost of customer service operations (Billing, Call Center, Field Services), load forecasting, out of warranty meter failures, and incremental IT equipment. These cost components are shown in Table II-6. The largest of these cost components is the Call Center operations component, which totals $166.4 million.

Table II-6
Post-deployment Steady State Incremental Operating Costs

Cost Component	Nominal ($000)
Billing	$82,300
Call Center	166,400
Field Services	157,700
Load Forecasting	10,200
Meter Failures	74,400
Personal Computer Equipment	5,800
Total	$496,800

c) Business Case Cost Drivers

There are two primary business case cost drivers for this cost category as shown in Table II-6. These cost drivers include customer service operations and out of warranty meter failures. The largest of these cost drivers is the customer service operations cost component, which is primarily the result of incremental Call Center costs expected to occur on an on-going basis as a result of an expected increase in calls and related call center activities. The call center costs also include the costs to implement a prepayment service. This is a new customer service that was not part of the SCE's previous business case analysis. This prepayment service can be offered as a result of the increased functionality of the AMI meter through the remote turn-on/turn-off capabilities.

The on-going steady state costs for the other customer service operations costs include Billing-related costs and Field Services related costs. The Billing costs primarily relate to an increase in manual processing of billing and usage exceptions (*i.e.*, billing and usage problems that require human intervention to resolve) that are expected to occur during the initial installation, and after the AMI deployment period is completed. The Field Services costs involve the incremental costs to conduct revenue protection activities in the absence of monthly meter reader visits. The Field Service costs also include the incremental cost of travel time for Field Service Representative (FSR) to handle the remaining field service orders. With fewer orders remaining, each FSR will be required to cover a larger territory handling what, on average, will be more complex service orders, and will spend a larger proportion of time traveling. The cost driver for the meter failure component relates to the incremental on-going costs SCE expects to incur for replacing failed AMI meters. This cost component also includes the incremental costs for meter technicians to assess the trouble reports for the failed AMI meters and provide a recommended course of action.

d) Post-deployment Steady-state Incremental Operating Cost Assumptions

The key assumptions for the two primary cost drivers in the Pre-Deployment Steady-State incremental operating cost category include the following.

(1) Customer Service Operations

For the Call Center operations, SCE assumed that all service activation requests will require an additional phone call to the call center where 25 percent of those calls will be handled by a Call Center representative and the remaining 75 percent will be handled through the use of the automated phone system (VRU). For calls related to disconnection and reconnection of service, SCE assumed that the more efficient disconnect capability of the AMI meter (over the manual disconnect process used today) will result in approximately 120,000 more disconnections per year. This increased volume is assumed to translate to two calls to the Call Center per disconnection where 66 percent of those calls will be handled by a Call Center representative and 34 percent will be handled through the VRU. In terms of reconnections, SCE assumed that all these incremental reconnections will require a call to the Call Center where 25 percent will be handled by an SCE Call Center representative and 75 percent will be handled by the VRU. Finally, for the credit-related call for pre-payment service, SCE assumed that 60 percent of those calls will be handled by a Call Center representative and 40 percent will be handled through the VRU. Of the 60 percent of prepayment calls handled by a Call Center representative, 70 percent of those calls will be handled by SCE's outsourced call center for credit-related calls while the remaining 30 percent will be handled by an SCE Call Center representative.

For the Field Service related customer service operation costs, SCE assumed that 14 incremental full-time employees (FTEs) would be needed to conduct revenue protection investigations that will be necessary in the absence of the monthly visits from the meter reader. The Field Service costs also include the additional drive time that remaining FSRs will need to incur to travel between the more complex field service orders completed by FSRs.

(2) Meter Failures

SCE assumed that one percent of the entire meter population per year will require a visit by an FSR to resolve a trouble order. Of that amount, SCE assumed that 0.5 percent will be a meter failure that needs to be replaced. SCE also assumed that a meter technician will need to analyze the meter trouble reports to properly diagnosis the cause of the AMI meter trouble and determine if a replacement is needed.

6. Program Management and Contingency Costs

a) Category Description

The Program Management and Contingency Cost category contains the costs that SCE expects to incur to properly manage a large complex project with the scope and scale of the AMI project. This category includes the costs for a Project Management Organization (PMO) capable of maximizing the potential benefit and completing the AMI project within reasonable cost and time parameters by managing project risks and unforeseeable conditions that may emerge. The PMO will make sure the AMI project meets the goals and functionality criterion established by the Commission in the R.02-06-001 proceeding as well as other related rulings and Commission decisions. This category also includes the costs for project contingencies to account for cost variations that may occur as determined by the use of a generally accepted risk model.

b) Summary of the Program Management and Contingency Cost Estimate

There are two cost components in this cost category that comprise the $177.1 million (nominal dollars). These cost components are PMO and contingency costs and are shown in Table II-7, the largest of which is the contingency cost component.

Table II-7
Program Management and Contingency Costs

Cost Component	Nominal ($000)
Program Management (PMO)	$42,800
Contingency	134,300
Total	$177,100

c) Business Case Cost Drivers and Assumptions

There are only two business cost drivers for this category. For the PMO cost component, the costs expected in this category relate to the project management oversight of the entire AMI project. The functions associated with the costs in the PMO component include project planning, project administration, budgeting, financial assessment and business case analysis, regulatory oversight, quality control, risk management, issue management, scope change management and business and organizational change management. The PMO costs include the use of an experienced systems integrator to support the management of the AMI project as well as a team of experienced SCE project managers trained in the Project Management Body of Knowledge (PMBOK) sponsored by the Project Management Institute. The use of a systems integrator and PMBOK experienced project managers will allow SCE to manage the AMI project in accordance with cost, quality and time constraints established by SCE and adopted by the Commission.

SCE estimated the contingency cost component using the Monte Carlo risk assessment model that was required by the Commission in previous AMI analyses. To determine this cost component, SCE developed a high/low range around the cost estimates for each cost category based on the maturity of, or confidence in each cost estimate. The Monte Carlo statistical simulation model was then used to analyze the combined ranges of estimates to calculate the contingency based on the varying level of uncertainty associated with each estimate for each cost component and to identify the level of confidence for the overall estimate.

E. Description of Benefits

1. Meter Services Operations

a) Category Description

Meter Services Operations benefits primarily consist of labor savings that arise from automating: (1) the manual collection of regular, on-cycle meter reads, (2) the manual collection of off-cycle, "pickup" reads, (3) the manual disconnection and reconnection of service, for nearly all residential and small commercial meters, (4) deferred meter sample testing, and (5) supervision and support associated with these current, manual activities. These are predominately labor benefits, and are all O&M benefits.

b) Summary of the Meter Services Operations Benefit Estimate

The major component of the Meter Services Operations benefit is labor. To estimate this benefit, SCE began with the current staffing levels for Meter Reading and for Field Services, as authorized in SCE's most recent General Rate Case. Current activity levels were determined for each of the impacted areas. In the case of Field Services activities, impacts to ongoing work (additional drive time due to a reduced number of Field Services Representatives) were also evaluated. In the case of routine meter reading, SCE presently expects that this activity will be virtually eliminated,[2] so its benefit estimate includes 100 percent of meter readers and meter reader supervisors currently in place. In addition, the benefit estimate includes the meter readers that otherwise would be added each year between 2009 and 2032, to handle projected customer growth.[3]

In the case of off-cycle "pickup" reads, SCE determined the amount of Field Services labor that is currently devoted to this task. Next, SCE determined the amount of Field Services labor that is devoted to field disconnection and reconnection activity. The result of this analysis was a forecast reduction in Field Services staffing after the AMI deployment is completed.

Finally, SCE estimated the benefits associated with these labor reductions, in vehicle costs, worker's compensation costs, facility costs, and claims costs. These benefits are all based on recorded levels of expenses, trended forward and pro-rated based on the number of meter readers and field services representatives anticipated to be reduced as AMI is deployed.

Table II-8
Meter Services Operations Benefits

Benefits Component	**Nominal** ($000)
Meter Readers/Supervision Labor	1,599,200
Field Services Reps/Supervision Labor	1,141,200
Vehicle Costs	164,000
Facility Costs	28,300
Workers' Compensation	51,700
Claims	3,300
Total	**2,987,700**

[2] One of SCE's goals in field testing the AMI meters and communications is to confirm the system's performance in rural areas. It is likely that a minimum number of meter readers will be retained in SCE's rural districts.

[3] SCE's cost-benefit analysis also includes the incremental cost of purchasing and maintaining AMI meters, rather than simple electromechanical meters, for the forecast customer growth between 2009 and 2032.

c) Business Case Benefit Drivers

The primary drivers for this category of benefits are the on-demand and scheduled remote-read features of the AMI meter, and the remote connect/disconnect feature.[4] Customer growth also drives this benefit, as the number of meter readers and field services representatives is forecast to rise over time, absent AMI.

SCE has included 100 percent of its current and forecast meter reading expenses, as well as its relevant field services expenses, in this benefit estimate. The sole "retained" activities are those field services activities which cannot be automated (primarily installation and maintenance of the meters themselves), and personnel in some of SCE's rural districts where a fixed minimum staffing level is needed.

SCE determined through the "Use Case" process undertaken in the Concept Design stage of Phase I that an integrated connect/disconnect switch in the meter would have numerous uses, including the automation of significant field activity. The benefits arising from this meter feature exceed the incremental cost of adding the switch.

d) Meter Services Operations Benefit Assumptions

The Meter Reading and Field Services Benefits include:

- The labor otherwise required to read meters on-cycle and off-cycle, reprogram meters for rate changes, and to perform field disconnect and reconnect activities.
- The pensions and benefit expenses associated with that labor.
- The vehicle expenses, workers' compensation expenses, and facility expenses associated with that labor.
- The deferral of SCE's meter sample test program during the AMI deployment period (2009-2012).

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[4] SCE anticipates that all AMI meters for electric service of 200 amps or less will have an integrated remote connect/disconnect switch. The 200-amp criteria includes approximately 93% of SCE's service accounts.

- The expenses associated with energy efficiency metering and meter reading, presently required to perform energy savings studies.

2. Billing

a) Category Description

Billing benefits primarily consist of cash-flow improvements that result from new prepayment services and more efficient Summary Billing, as well as reduced bad debt expense. Billing benefits also include labor reductions that are expected to result from fewer billing exceptions, and from a reduction in back office processing for turn-offs and turn-ons.

b) Summary of the Billing Benefit Estimate

The largest component of Billing benefits relates to SCE's proposed prepayment services. SCE's "Use Case" process identified the potential to offer prepayment services, as a result of incorporating an integrated remote connect/disconnect switch in the AMI meter. SCE expects that some customers facing difficulty establishing credit, meeting the utility's tariffed deposit requirements or on fixed incomes, would choose prepayment service as an alternative. Prepayment service would result in two major benefits to SCE: (1) an improvement in cash flow, which would reduce SCE's working capital requirement, as electricity would be paid for prior to consumption instead of afterward; and (2) a reduction in bad debt expense, as customers most at-risk for write-off would enroll in this service.

Billing benefits also include a reduction in bad debt that will arise from SCE's ability to enforce its existing disconnect policies more rigorously. At present, field disconnect orders are not worked on Fridays, and never worked on Saturdays or Sundays[5], and they are a low priority on the four weekdays they are eligible to be performed. In addition, the cost of a field visit to disconnect service is not trivial, so SCE does not typically disconnect for

[5] SCE's tariffs provide for higher reconnection charges on weekends. As a matter of policy, SCE does not wish to force its customers to pay the higher weekend-reconnection charge, which prevents disconnect work Friday-Sunday.

balances below $30. As a result, less than half of potential disconnects are actually performed. With the AMI meter's remote connect/disconnect capability, however, SCE can perform a disconnect every time its tariffs and policies so dictate. This capability is anticipated to reduce bad debt expense by more than $1.5 million per year after full deployment of AMI. SCE will also be able to manage the over 1 million service changes due to customers moving by performing service turn-ons and offs as opposed to the manual method used today.

Another significant Billing benefit is the cash flow improvement associated with the ability to synchronize billing reads for Summary Billing accounts. Presently, SCE reads electric meters in geographic sequence within individual service districts. Summary Billing accounts may have individual service accounts located in different routes, cities, districts, and counties – making it impractical and costly to obtain those reads in a coordinated fashion. As a result, one service account may be read on the 1st of the month, but that service account remains unbilled until the final service account on the Summary Billing statement is read, which may be the 10th of the month, or the 20th. Upon full deployment of AMI, SCE will obtain meter reads daily from all accounts, and can easily coordinate the billing reads for all service accounts on each Summary Billing account to occur on the same calendar day. This capability will enable SCE to reduce unbilled revenue from Summary Billing accounts to nearly zero, and will reduce SCE's working capital requirements.

Finally, SCE anticipates some labor savings in Billing. The accuracy provided by the AMI system, as well as the data validations provided by the new Meter Data Management System, will result in reduced billing exceptions. In addition, some back-office processing associated with off and on orders will be reduced.

Table II-9
Billing Benefits

Benefits Component	**Nominal** ($000)
Bad Debt	143,400
Cash Flow Improvement	316,400
Reduced Billing Labor	51,900
Total	**511,700**

c) Billing Benefit Driver

The primary regulatory driver for billing related benefits is the Commission's ultimate approval of prepayment services. SCE proposes this to be a completely optional service to its existing tariffs and services. SCE envisions that participating customers would be able to check their remaining prepaid account balances via the internet, via phone, or via an in-home display . This driver affects both the bad debt reduction and the cash-flow improvement benefit estimates.

The second strong driver of billing related benefits is the cash flow improvements anticipated from prepayment service, and from reducing the amount of unbilled revenue from Summary Billing accounts. Because this cash flow would accrue to working capital, which is a component of rate base, SCE has valued this cash flow improvement at the same Long-Term Cost of Capital used to calculate the revenue requirement impact of the AMI business case, and to discount the cash flows to ratepayers.

The final driver of billing related benefits is the forecast rate at which customers would choose prepayment service. SCE is presently estimating that by 2012, as many as 10% of SCE's residential and small business customers will opt for prepayment service. This estimate is based on results to-date from Salt River Project, consumer trends in other service industries and socioeconomic trends for SCE's customer base.

SCE has used recorded data on its Summary Billing accounts to determine the total amount of revenue, as well as the average "lag", for its existing accounts. In addition, while Summary Billing revenue was assumed to grow at the rate of overall customer growth, no growth in the proportions of service accounts on Summary Billing was assumed.

SCE has consistently used its Long-Term Cost of Capital throughout this case, to discount costs and benefits alike. Since any change in Summary Billing lag or prepaid service payments would flow directly to SCE's working capital accounts, and these accounts are included in the calculation of rate base in each General Rate Case, this rate is appropriate to use to value the benefit of accelerating customer payments for electric service.

The reduction in exception processing work is based significantly on a preliminary understanding of the capabilities and performance of the new Meter Data Management System that SCE expects to procure and install during Phase II. The actual system and configuration installed may impact the benefits actually realized in this area.

d) Billing Benefit Assumptions

The Billing Benefits include:

- A reduction in Bad Debt expense from more timely and uniform disconnect for late payments.
- A reduction in Bad Debt expense from customer migration to Prepaid electric service.
- Accelerated cash flow from customer migration to prepaid electric service.
- Accelerated cash flow from eliminating unbilled revenue "lag" from Summary Billing accounts.
- A reduction in labor costs to process billing exceptions, as a result of more accurate billing reads.
- The pensions and benefit expenses associated with that labor.

3. Call Center

a) Category Description

Call Center benefits consist of labor, and labor-related costs, arising from a reduction in customer call activity that will result from AMI deployment. First and foremost, after-hours customer calls requesting estimated service reconnection times are expected to be reduced. In addition, SCE forecasts a reduction in billing inquiry calls, as a result of more accurate meter reads.

b) Summary of the Call Center Benefit Estimate

Presently, SCE's Call Centers experience significant call volumes from customers who are waiting for service to be connected or reconnected. Since the AMI meter will allow near-instant[6] remote service reconnection, these calls should be virtually eliminated after AMI deployment. In addition, SCE expects billing inquiry calls to be reduced as AMI will provide more accurate billing data.

Table II-10
Call Center Benefits

Benefits Component	**Nominal** ($000)
Reduced Call Volumes – Labor	98,100
Total	**98,100**

c) Call Center Benefit Drivers

The Call Center benefits are driven mainly by the AMI system's capability to perform service reconnections in near-real time, thus eliminating customer callbacks. This capability derives both from the remote reconnect switch in the AMI meter, as well as the system's ability to translate a call center representative's keystrokes into a meter command, and transmit it to the meter. Billing inquiry calls are also subject to fluctuation, based on the amount of data and clarity of presentation on customer bills, as well as on SCE's website. Customers that understand their bill based on information contained on the bill itself, or through information provided on SCE's website, are less likely to call SCE.

SCE has assumed that AMI deployment will eliminate three customer calls, for every four reconnect transactions. The design of the AMI system will assure that

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[6] Safety considerations will require that customers who make satisfactory payment arrangements must then confirm the premises are safe before the meter can be energized. This may take the form of a second customer call or other means of confirmation.

nearly all reconnect transactions can be completed with a single phone call, or with a second "confirmation" call from the customer to an automated voice-response line. Thus, the significant labor associated with these calls will be avoided.

In addition, SCE assumes that 25 percent of the current billing inquiry call volume is related to actual meter read errors, which will be eliminated with AMI deployment. Thus, the benefit from improved reading accuracy is 25 percent of the current volume of billing inquiries.

d) Call Center Benefit Assumptions

The Call Center Benefits include:

- The labor otherwise required to answer customer inquiries about pending reconnection activity.
- The labor otherwise required to answer customer inquiries about erroneous meter reads.
- The pensions and benefit expenses associated with that labor.
- The inbound toll-free charges associated with the avoided calls.

4. TDBU Operations

a) Category Description

Transmission and Distribution Business Unit (TDBU) Operations benefits arise from: (1) a reduction in work for "no-power" calls where power is actually on, and (2) improved prevention of transformer overloads, by enhanced monitoring and controlling of load. The no-power call reduction benefits are O&M, and the transformer overload prevention benefits are capital.

b) Summary of the TDBU Operations Benefit Estimate.

At present, SCE's call centers have no way to verify if a meter has power when customers call about power outages. Many times, the call centers will notify TDBU Operations to send a troubleman to the customer's premise only to find that the meter is in fact energized, and the problem is on the customer's side of the meter - thus beyond SCE's jurisdiction. With AMI, the call center staff will be able to send a signal to the meter and verify whether the meter is energized, while the customer is on the phone. As a result, false "no-power" service calls can be virtually eliminated with AMI deployment.

Transformer loadings are currently calculated by associating individual meters with transformers in a database and then using loading factors to translate monthly cumulative kWh usage into a "peak load" estimate. With AMI, actual hourly kWh usage can be used to identify overloaded transformers which can then be scheduled for replacement on a more proactive versus. reactive basis, thus mitigating some overtime.

Table II-11
TDBU Operations Benefits

Benefits Component	**Nominal** ($000)
Avoided Dispatch – Labor	76,800
Transformer Overloading	25,600
Total	**102,400**

c) TDBU Operations Benefit Drivers

The primary business case driver for avoided "no-power" calls is the pace of AMI deployment, as these benefits ramp-up in proportion to the number of customers whose AMI meters can be checked prior to sending a troubleman. The primary business case driver for transformer loading benefits is also the pace of AMI deployment, as transformer loading analysis can be upgraded as soon as all service accounts on a circuit or transformer have been upgraded to AMI meters.

The number of "no-power" calls is currently estimated at 65 per day, and these customer visits require one hour of labor for each call. Eliminating these field visits will reduce labor costs by approximately 13 FTEs.

The difference between replacing a transformer during normal work hours, and replacing it on overtime is approximately $1,300. While no predictive maintenance system is perfect, SCE believes that with full deployment of AMI together with the development of a new predictive transformer loading replacement program, overtime associated with responding to many of the approximately 1,700 transformer failures per year can be mitigated.

d) TDBU Operations Benefit Assumptions

The TDBU operations benefits include:

- Reduced labor otherwise required to respond to customer "no-power" calls, where the meter is actually energized.
- Reduced overtime labor associated with replacing overloaded transformers after they fail.
- Reduced pensions and benefit expenses associated with that labor.
- Reduced vehicle expenses associated with that labor.

5. Demand Response

a) Category Description

Demand response benefits accrue because AMI enables dynamic pricing, better customer information about usage and energy costs and load control programs enhanced by two-way communications. Dynamic pricing, better information and enhanced load control programs contribute to providing SCE customer generation and energy procurement savings as well as savings from transmission and distribution infrastructure capital deferrals. Procurement benefits are classified as O&M (ERRA) benefits, while the Distribution Deferral benefits are classified as capital.

b) Summary of the Demand Response Benefit Estimate

Demand Response benefits fall into two major groups: (1) Price Response, where customers take actions as a result of adopting a Time-of-Use tariff, and (2) Load Control, where the AMI system activates one or more customer-premise devices in response to a utility signal to curtail load, for economic or system stability purposes.

Table II-12
Demand Response Benefits

Benefits Component	**Nominal** ($000)
Load Control (Procurement)	693,000
Load Control (Deferred Capital)	188,600
Price Response (Procurement)	1,511,000
Price Response (Deferred Capital)	83,400
Total	**2,476,000**

c) Business Case Benefit Drivers

There are numerous regulatory and business case drivers for Demand Response benefits, including the number of customers who will adopt TOU, CPP, or other time-differentiated rates; the dollar value of avoided energy and capacity purchases; the applicability of AB 1X to default time-differentiated rates; the amount of energy customers conserve monthly or annually due to AMI enabled information about their usage and costs; and the level of responsiveness (or peak demand reduction) from customers who adopt time-differentiated rates.

SCE has used illustrative tariffs in this application, but will propose specific tariffs (in its full deployment application). The demand response benefits are highly dependent on the specific terms and conditions of the tariffs, so the primary regulatory driver of Demand Response benefits is the degree to which the approved tariffs match those proposed in the full deployment application.

SCE continues to utilize the results from the Statewide Pricing Pilot (SPP) to determine both the level of customer adoption of time-differentiated rates, as well as the degree of price-responsiveness of those customers who adopt the rates. The SPP experiment was conducted over a two-year period and may not represent the full effect of long term availability of pricing information and time-differentiated tariffs. For example, academic literature on price elasticity of demand demonstrate that price elasticity and energy conservation from time-differentiated tariffs are generally higher over the long term than in the short run. Over the long term, customers make investments in their building structures (*e.g.*, energy-efficient windows and better insulation) as well as lighting equipment and appliances commensurate with their exposure to peak period pricing. SCE has not included the demand response effects of long term adoption of time-differentiated rates at this time but will continue to evaluate this for the final AMI Phase III application.

SCE will continue to evaluate approaches to achieving significant demand response. SCE's approach relies heavily on TOU rates and load control. The other investor-owned utilities proposed differing approaches. The largest small customer discretionary load coincident with our system peak is air conditioning. SCE's experience in load control provides confidence that an AMI delivered program can enhance customer participation with two-way communicating PCTs. AMI can enable a pay-for-performance approach, for example. For time differentiated tariffs, SCE will continue to investigate different approaches including one that provides customers a reward for participation rather than a penalty. SCE also will evaluate a three-part TOU rate and other options.

d) Demand Response Benefit Assumptions

The overarching assumptions in the analysis of Demand Response benefits include:

- Meters and Communications
  - All customers below 200kW will be equipped with AMI meters per the deployment schedule.
  - Residential meters will provide at least hourly interval data, collected each day and available for customer viewing next day. Commercial and industrial customer meters will provide 15 minute interval data.
  - Two-way communications with the meter and any associated PCTs will be enabled.
- Tariff Enrollment Assumptions
  - For residential customers, customer enrollments were estimated using the Momentum Market Intelligence model developed in the Statewide Pricing Pilot program. The model uses bill impact assessments to determine enrollment preferences. Commercial enrollments percentages were assumed to be the same for C&I customers except in the case of mandatory TOU for large customers (>100kW).

- Assumes that AB 1X rate requirements expire when SCE's DWR contracts expire 12/31/2011. AB 1X compliant TOU rates will be offered between 2009 and 2011. Standard two-part TOU rates will be offered in the remainder of the study period (2012 to 2032).

- Residential and C&I customers below 100kW in demand will be defaulted to a Time of Use (TOU) rate when they receive an AMI meter. Residential default TOU rates will be compliant with AB 1X. The AB 1X compliant rate would continue to maintain a rate freeze on all usage up to 130 percent of baseline. TOU pricing will be applied to usage above 130 percent of baseline. The assumed sustained enrollments of residential customers on TOU rates are 44 percent on AB1-X compliant rates and 58 percent on non-AB1-X rates. C&I customer enrollment in TOU is assumed to be 58%.

- Residential and C&I customers below 100kW in demand will voluntarily enroll in CPP-F rates when they receive an AMI meter. When AB 1X is in force, residential CPP enrollment is assumed to be 20 percent (2009 to 2011). After 12/31/2011, CPP enrollment is assumed to be 11 percent.

- C&I customers 100kW and above will be defaulted to a mandatory TOU rate with the option to choose a CPP-F rate. The assumed adoption rate is 88 percent TOU and 12 percent of customer will opt-out to CPP-F.

- Load Control Program Assumptions

  - Title 24 compliant PCTs will be available and installed in new homes and HVAC retrofits requiring permits beginning in 2009.

  - SCE will offer and market a load control program to customers with Title 24 PCTs and AMI meters and 25 percent will enroll. Customers will be paid an incentive to participate.

  - SCE will discontinue new enrollments on the current AC Cycling Program (ACCP) in 2009 which is assumed to reach 340,000 enrollees by then. The ACCP program will continue with moderate attrition. Beginning in 2009, the ACCP program will be changed for customers equipped with AMI meters. The program will be economically dispatched more often for shorter durations to shave the system peak rather than only dispatched for reliability purposes.

  - A Smart Thermostat program (using Title 24 compliant PCTs) will be offered beginning in 2009 to residential customers with AMI meters and central air conditioning. A marketing program will initially enroll 60,000 customers per year until approximately 250,000 customers are enrolled. Enrollment at 250,000 will be maintained. SCE will pay for equipment and installation. Customers will be paid an incentive to participate.

- The present analysis is conservative in that it does not include load control programs for C&I customers. C&I customers have participated in the SPP Smart Thermostat program and significant load reductions were experienced. SCE will continue to evaluate the potential for C&I participation in load control programs and in tariffs with enabling equipment. SCE may include load control or tariffs with enabling equipment for C&I in its Phase III application.

- Demand Response
  - SPP results for price elasticity and the Charles River Associates PRISM model are used to determine load reductions for SCE territory.
  - No increase in prices elasticity for long term effects is included at this time. SCE will continue to examine whether long run price elasticities should be taken into account.
  - An energy conservation effect is included due to mass implementation of dynamic rates and the widespread availability of pricing and other information to customers about their energy usage and costs.

- Procurement Benefit Assumptions
  - SCE's latest forecast for avoided capacity and energy costs is included. The forecast relies on a Combustion Turbine (CT) proxy. The capacity value for CPP and load control is discounted due to their limited availability compared to a CT.
  - Includes avoided reserves and distribution losses.

- Transmission and Distribution Capital Deferral Assumptions
  - The Transmission and Distribution assumptions include a benefit from the deferral of capital expenditures for transmission and distribution due to reduction in local system peak demand from AMI tariffs and programs.

    Demand Response Benefits include:

    - The avoided energy and capacity procurement (or construction) costs that would otherwise be required to serve peak load in the absence of AMI-enabled time-differentiated rates.
    - The avoided energy and capacity procurement (or construction) costs that would otherwise be required to serve peak load in the absence of AMI-enabled load control.

- The avoided distribution capital costs associated with system upgrades otherwise required to serve peak load in the absence of AMI-enabled time-differentiated rates.

- The avoided distribution capital costs associated with system upgrades otherwise required to serve peak load in the absence of AMI-enabled load control.

e) Conclusion

It is important to note that due to the substantial backlog of work TDBU currently has and expected to continue to have in the future, any realized AMI benefit will be used by TDBU to do more work with its existing and planned workforce under current Commission approved budgets. Of the $2.476 billion of demand response benefits, $272 million ($188.6 million for load control and $83.4 million for price response) are associated with deferred TDBU capital projects. This savings will enable TDBU to perform additional infrastructure replacement work.

6. Other Benefits

a) Category Description

The Other Benefits arising from AMI fall into three groups: (1) the avoided cost of purchasing electromechanical meters; (2) improvements in real-time energy purchases and sales resulting from actual interval data on SCE's entire customer base; and (3) avoided costs of computers and handheld devices for SCE labor that will be avoided as a result of AMI deployment.

b) Summary of the Other Benefit Estimate

For modeling clarity, the entire estimated cost of AMI meters, for both initial deployment (retrofit) and customer growth, is included as a cost of AMI deployment.[7] However, to ensure that ratepayers obtain the full benefit of AMI, the avoided cost of procuring electromechanical and solid-state (non-AMI) meters is included as a capital benefit.

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[7] *See* Volume 3, Section II.D for assumed AMI meter costs

SCE presently purchases and sells energy in the day-ahead and hour-ahead markets. If the day-ahead forecast is not 100% accurate, purchases and sales must be made in the hour-ahead market to balance energy supply with demand. Day-ahead forecasting is currently made with profiled load data for SCE customers, since interval data does not exist for most SCE customers. Full deployment of AMI will make interval data for the entire SCE customer population available for forecasting purposes, and for day-ahead energy purchasing. SCE believes the accuracy of its day-ahead energy purchasing can be improved by ¼ of one percent (0.0025%), and less-advantageous hour-ahead purchases and sales can be reduced. This O&M benefit does not appear for two years following the completion of AMI deployment (or 2014) due to the need for forecasters to analyze one full year of system wide interval data in order to improve their forecasting models.

Most SCE employees involved in the meter reading, field services, meter installation, call center, and billing operations require a desktop, laptop, or portable computing device to perform their jobs. To the extent that AMI results in fewer employees doing these tasks manually, there will be benefits from no longer purchasing and maintaining these computing devices. For this estimate, standard SCE configurations for desktop and laptop computers were used, and amortized over 4-year and 3-year assumed lives (respectively) to calculate a proxy lease cost, which was applied as an O&M benefit to each full-time equivalent employee impacted by AMI deployment.

Table II-13
Other Benefits

Benefits Component	**Nominal** ($000)
Avoided Meter Capital	337,600
Load Forecasting	13,800
Avoided Computing Devices	28,400
Total	**379,800**

c) Other Benefit Drivers

Since the Infrastructure Procurement Costs include all estimated AMI meter costs over the duration of the analysis period, it is necessary to include an offset for the avoided cost of non-AMI meters that would have otherwise been purchased. Thus, the avoided meter capital benefit is SCE's current meter procurement budget for non-AMI meters for the full duration of the AMI analysis period. The load forecasting benefits are based on power procurement cost savings that are expected to result from an assumed increase in forecasting accuracy. This improvement in load forecasting accuracy results from replacing load-profile sample data with actual interval data for all SCE customers. The avoided computing device costs result from the estimated avoided cost of purchasing computing devices (hand held and lap-top) that would otherwise have been needed, primarily for meter reading and field services personnel. This estimate is based on the number of SCE positions that will be reduced as a result of AMI deployment and a reasonable proxy that amortizes the cost of relevant computer hardware over the normal life of the device.

d) Other Benefit Assumptions

The Other Benefits include:

- The avoided meter capital costs that would otherwise be incurred to purchase electromechanical (cumulative) meters, demand meters, and solid-state non-communicating interval meters for non-RTEM customers, in the absence of AMI.
- An improvement of ¼% (0.0025%) in day-ahead/hour-ahead energy purchases, as a result of better forecasts that rely on actual interval usage data for all SCE customers instead of load profiles.
- A reduction in PC and mobile computing devices as SCE employee levels are reduced as a consequence of AMI deployment.

F. Societal (Non-Financial) Benefits

SCE also acknowledges a group of benefits that are not readily quantified, but can be identified as improvements to customer service, service reliability, social equity, and the like. While these are not yet part of the cost-benefit analysis, SCE believes these benefits are important for the Commission to consider from a policy perspective. These benefits include potential reductions to energy theft, potential environmental improvements that result from reduced generation and from substituting more-efficient off-peak generators for less-efficient on-peak units, and additional reliability benefits that could derive from the activation of all Title 24 PCTs. SCE will discuss these in more detail in its AMI full deployment application, expected to be filed with the Commission in mid-2007.

III.

ANALYSIS OF AMI REVENUE REQUIREMENT AND RATEPAYER IMPACTS

This section describes the AMI cost-effectiveness analysis performed by SCE that compares ratepayers' benefits from implementation of AMI to the project costs resulting from implementation of AMI. The benefits of AMI are the costs that ratepayers avoid as a result of AMI. Specifically, this avoided cost is the difference between what ratepayers would have to pay for service assuming AMI is implemented starting in 2008, and what they would have to pay assuming no implementation through 2032.

The following equation sets forth the benefit-to-cost ratio for AMI:

$$\text{Benefit-to-Cost Ratio} = \frac{\text{PV of Ratepayer Benefits}}{\text{PV of Ratepayer Costs}}$$

The 2007 present value of the revenue requirement (PVRR) of Ratepayer Benefits for AMI were calculated at $1,303. The 2007 PVRR of project costs were calculated at $1,197. The resulting benefit-to-cost ratio is 1.09 to 1. SCE found that benefits exceed costs.

A. Methodology

SCE's cost-effectiveness evaluation of AMI is a life-cycle benefit-to-cost analysis from a ratepayer perspective. SCE's life-cycle perspective measures total benefits and costs from 2007-2032. Because benefits and costs occur over many years, SCE used net present value (NPV) analysis to bring all benefits and costs to the base year of 2007. Measuring benefits and costs from a ratepayer perspective means that SCE valued all benefits and costs using the revenue requirement that ratepayers would incur or avoid.

1. Benefit-To-Cost Analysis

NPV is the discounted monetized value of expected net benefits (*i.e.*, benefits minus costs). NPV assigns monetary values to benefits and costs, discounts future benefits and costs using an appropriate discount rate, and subtracts the sum total of discounted costs from the sum total of discounted benefits. Discounting benefits and costs transforms gains and losses occurring in different time periods to a common unit of measurement. The ratio of the NPV of benefits to the NPV of costs is the benefit-to-cost ratio. Values above 1.0 indicate projects which benefit ratepayers.

In this analysis, the benefits of AMI are the difference between avoided costs from AMI and the incremental ongoing costs (post 2012) ratepayers would incur from AMI implementation. Table III-14 shows the PVRR for ratepayer net benefits.

2. Revenue Requirement Model

a) Purpose of the Revenue Requirement Model

To quantify ratepayers' benefits resulting from AMI, it is necessary to determine the avoided and incremental costs that ratepayers will incur from 2007-2032 due to AMI Implementation. To do this, SCE converts the avoided and incremental costs into the ratepayers' revenue requirement.

To quantify ratepayers' AMI project costs (2007-2012 implementation capital), it is necessary to determine the annual payments equivalent to the AMI project costs. Therefore, SCE also converts the project costs into a revenue requirement.

Because ratepayers pay revenue requirements over a number of years, to compare different revenue requirements, it is necessary to put them on a consistent basis relative to the timing of payments. This conversion to a consistent basis is called Present Value (PV) analysis. For the AMI benefit-to-cost analysis, SCE converted each revenue requirement into a single PV that assumes 2007 as the base year.[8] Therefore, the purpose of the revenue requirement model is two-fold. First, the model converts SCE's costs (either avoided or expected) into a revenue requirement which ratepayers would expect to pay. Second, the model changes these streams of revenue requirements paid over a number of years into a single PV.

Table III-14 lists the PV of ratepayers' benefit due to the AMI.

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8 Present value calculated using SCE's 10% incremental cost of capital.

Table III-14
Ratepayer PVRR of Benefits
Resulting from AMI Implementation
($ in millions)

Ratepayer Avoided Costs from AMI Implementation	
Capital Savings	$336
|O&M Savings	$954
Demand Response Savings	$563
Total: Ratepayer Avoided Costs from AMI Implementation	$1,853
Incremental Ongoing Costs from AMI Implementation	
Incremental Capital (Post 2012)	$133
Incremental O&M	$417
Total: Incremental Ongoing Costs from AMI Implementation	$550
Ratepayer benefit	$1,303

The PV of project cost for AMI Implementation is $1,197 million.

b) Overview of Revenue Requirement Model

As described above, SCE used the revenue requirement model to: (1) convert costs incurred by the utility into a revenue requirement paid by ratepayers; and (2) translate the revenue requirement into a PV for comparison purposes. The testimony below describes the methodology for each of these tasks.

(1) Conversion of Costs Into a Revenue Requirement

A utility's cost of service, or revenue requirement, is all of its operating expenses plus a return on its investment. Therefore, the revenue requirement equals the sum of all costs necessary to meet its obligation to serve. The following formula expresses this revenue requirement:

Revenue requirement = Operation and Maintenance (O&M) expense +
Depreciation expense +
Tax expense +
Return on investment

O&M expense is the cost of routine work that SCE performs to supply electric service during the course of a year. O&M expenses include labor, materials, supplies, and variable administrative and general (A&G) expenses.

Depreciation expense is the charge against earnings that SCE takes each year to allow for the recovery of an investment (including removal costs) over its useful life.

Tax expense includes taxes based on income, miscellaneous taxes, and Ad Valorem (property) taxes on incremental investment.

Return is the cost of capital SCE incurs to finance its long-term investments. SCE multiplies the rate of return by its prudently incurred long-term investment to calculate its return. For the AMI benefit-to-cost analysis, SCE used its incremental cost of capital. SCE's prudently incurred long-term investment is its Rate Base. The following formula illustrates the calculation of Rate Base:

Rate Base = Fixed capital - Reserves

Fixed capital is the sum of the plant in service, intangible plant including capitalized software, and plant held for future use. Reserves include accumulated depreciation, accumulated amortization, and accumulated deferred taxes.

(2) Translate the Revenue Requirement into a Present Value

As previously discussed, once SCE has calculated the revenue requirements for each cost component, it is necessary to put them on a consistent basis relative to the timing of the ratepayers' payment. Table III-15 lists the annual revenue requirements for each of the cost components used in the benefit-to-cost analysis. Section b1 above, describes the calculation of these revenue requirements. Table III-16 below compares the sum of each revenue requirement to the PV of each revenue requirement.

Table III-15
Summary of AMI Revenue Requirement
($ millions)

	INCREMENTAL OPERATING COSTS			AVOIDED COSTS						
	CAPITAL	O&M	Total Costs	O&M Savings	Capital Savings	Demand Response	Total Avoided Costs	**Ratepayer Benefits**	**Project Cost**	**Net Benefit**
2007	-	32,277	32,277	-	-	-	-	(32,277)	-	(32,277)
2008	-	10,980	10,980	(55)	-	-	(55)	(11,035)	15,897	(26,932)
2009	-	49,949	49,949	12,194	1,832	7,022	21,048	(28,900)	44,922	(73,822)
2010	-	60,619	60,619	36,445	9,524	21,238	67,207	6,588	106,521	(99,933)
2011	-	62,824	62,824	62,419	20,656	37,334	120,408	57,584	162,078	(104,495)
2012	-	57,781	57,781	93,342	30,905	52,064	176,310	118,529	214,738	(96,209)
2013	1,106	39,657	40,763	111,766	39,306	61,351	212,423	171,660	226,387	(54,728)
2014	4,965	39,544	44,509	115,688	44,161	67,328	227,176	182,668	213,463	(30,795)
2015	9,682	39,921	49,602	121,353	47,394	73,181	241,928	192,326	202,135	(9,810)
2016	13,850	33,759	47,609	127,113	49,825	76,183	253,121	205,512	191,390	14,123
2017	17,492	34,270	51,763	133,087	51,543	80,017	264,647	212,884	181,076	31,808
2018	19,815	35,336	55,151	139,361	53,004	83,940	276,305	221,154	171,579	49,574
2019	22,439	36,878	59,317	145,940	54,511	88,348	288,799	229,482	162,146	67,336
2020	25,420	37,185	62,604	152,832	56,546	91,861	301,238	238,634	152,690	85,943
2021	28,604	37,216	65,820	160,056	58,787	96,282	315,125	249,306	143,217	106,088
2022	32,533	38,639	71,173	167,577	60,391	100,834	328,802	257,630	133,712	123,917
2023	36,202	39,920	76,122	175,493	62,079	105,488	343,061	266,939	124,164	142,774
2024	39,334	40,838	80,171	183,839	63,886	110,264	357,989	277,818	114,571	163,247
2025	41,928	42,774	84,702	192,596	65,859	115,134	373,589	288,887	105,118	183,769
2026	45,037	43,840	88,877	201,857	68,071	120,134	390,063	301,186	95,986	205,200
2027	48,342	45,153	93,495	211,521	70,642	125,276	407,439	313,944	87,135	226,809
2028	52,393	46,735	99,128	221,769	73,780	130,527	426,076	326,947	78,019	248,928
2029	56,924	48,393	105,317	232,512	76,308	136,989	445,809	340,491	51,046	289,446
2030	64,413	50,198	114,612	244,088	79,598	142,330	466,016	351,404	24,030	327,374
2031	79,703	52,092	131,795	256,216	87,380	148,963	492,559	360,764	(561)	361,325
2032	98,295	54,078	152,373	268,923	84,814	154,576	508,314	355,941	(33,443)	389,384
Total	738,478	1,110,855	1,849,333	3,767,931	1,310,802	2,226,665	7,305,397	5,456,064	2,968,018	2,488,046
2007 PV	133,243	417,108	550,351	954,310	336,704	563,159	1,854,174	1,303,823	1,197,493	106,330
									2007 B-C Ratio	1.09

Table III-16
Ratepayer Benefits Resulting from AMI Implementation
($ in millions)

	Sum of Annual Revenue Requirement	PVRR
Ratepayer Avoided Costs from AMI Implementation		
Capital Savings	$1,311	$336
O&M Savings	$3,768	$954
Demand Response	$2,227	$563
Total: Ratepayer Avoided Costs from AMI Implementation	$7,305	$1,853
Incremental Ongoing Costs from AMI Implementation		
Incremental Capital (Post 2012)	$738	$133
Incremental O&M	$1,111	$417
Total: Incremental Ongoing Costs from AMI Implementation	$1,849	$550
Ratepayer Benefit	$5,456	$1,303
AMI Project Costs	$2,968	$1,197

The difference between the sum of the annual revenue requirements and the PV of the revenue requirements is due to the timing of the ratepayers' payments. The earlier the ratepayer pays the revenue requirement, the higher the PV. The following formula translates the revenue requirement into the PV:

$$PV = \frac{RR_1}{(l + r)} + \frac{RR_2}{(l + r)^2} + \ldots + \frac{RR_n}{(l + r)^n} = \Sigma \frac{RR_i}{(l + r)^i}$$

where:

RR - represents the revenue requirement costs.

i - Represents the year in which ratepayers pay the revenue requirement.

n - Represents the year considered.

r - Represents the discount rate (the discount rate quantifies the willingness of ratepayers to exchange present costs and benefit for future costs and benefits).

B. Benefit-To-Cost Ratio Results

Figure III-2 below shows how SCE calculates the benefit-to-cost ratio for AMI in three representations of the same equation. Each representation of the equation provides more details of the data utilized in the calculation. Equation No. 1, shows at the most summary level the benefit-to-cost ratio, comparing ratepayer benefits to ratepayer costs. Equation No. 2, in Figure III-2, shows how the ratepayer benefits are calculated by subtracting the Present Value Revenue Requirement (PVRR) of incremental operating costs from avoided costs. The result of that equation is then divided by the PVRR of AMI project costs.

Equation No. 3 in Figure III-2 delves even more deeply into the details of determining the PVRR for avoided and incremental costs. Equation No. 3 shows that the PVRR of avoided costs are equivalent to the PVRR of capital savings, O&M savings, and demand response savings. From this PVRR SCE subtracts the PVRR of incremental operating costs. The PVRR of incremental operating costs is the PVRR of incremental capital plus the PVRR of incremental O&M. This PVRR of ratepayer benefits is then divided by the PVRR of AMI project costs.

Figure III-2
Detailed Benefit-To-Cost Framework

1. $$\text{Benefit-To-Cost} = \frac{\text{PV of Ratepayer Benefits}}{\text{PV of Ratepayer Costs}}$$

2. $$\text{Benefit-To-Cost} = \frac{\text{PVRR of Avoided Costs - PVRR of Incremental Costs Benefits}}{\text{PVRR of Project Costs}}$$

3. $$\text{Benefit-To-Cost} = \frac{\begin{array}{c}\text{PVRR of (Capital Savings + O\&M Savings + Demand Response)}\\ \text{LESS PVRR of (Incremental Capital + Incremental O\&M)}\end{array}}{\text{PVRR of Project Costs}}$$

Table III-17 shows the results of SCE's benefit-to-cost calculation.

Table III-17
Benefit-To-Cost Calculation
($ in millions)

Ratepayer Avoided Costs from AMI Implementation	$1,853
Incremental Ongoing Costs from AMI Implementation	$550
Ratepayer Benefits	$1,303
Ratepayer Project Costs	$1,197
Benefit-To-Cost Ratio	1.09
Net Benefit	$106