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SOUTHERN CALIFORNIA
EDISON

An *EDISON INTERNATIONAL* Company

(U 338-E)

Testimony Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism

Volume 1 – Business Vision, Management Philosophy, and Summary of Business Case Analysis

Before the

Public Utilities Commission of the State of California

Rosemead, California

March 30, 2005

EXECUTIVE SUMMARY

Southern California Edison Company (SCE) has completed an extremely rigorous business case analysis of Advanced Metering Infrastructure (AMI). SCE's findings indicate that an integrated AMI solution that leverages additional commercially-available technologies has the potential to provide an effective platform for enhancing routine customer services, providing more sophisticated alternatives for load management and demand response, and increasing operational efficiencies and benefits. However, these enabling technologies have yet to be cost-effectively packaged or integrated into a streamlined meter for application in the United States. Therefore, SCE has concluded that given its operational starting point, an investment in currently-available AMI technology is not cost effective for SCE's customers. Instead, SCE proposes to achieve significant increased operational and demand response benefits through a concerted and aggressive effort to develop an "advanced integrated meter" (AIM) that integrates additional technologies into the next generation of meters.

SCE's business vision for AMI seeks to undertake a deliberate, yet fast-paced effort to design and develop a new AIM platform that will better meet SCE's and its customers' needs by integrating additional proven technologies. The goal of the AIM project will be to add significantly more functionality at the same or lower cost as today's solutions, in order to significantly increase benefits over the current AMI business case.

The AIM development will take a "clean sheet" approach to design a meter that provides additional functional capabilities not available in currently-available metering solutions, including the possible integration of load control, demand limiting, two-way communications, customer information displays, data storage, and/or other proven stand-alone technologies. SCE seeks to significantly increase overall durability and versatility of AMI by using open, extensible and multifunctional meter and communications platforms. The AIM project is expected to leverage commercially-available components through an open design for both the meter device and communications to provide a flexible and sustainable technology platform during its long lifecycle. This is essential given recent and anticipated future technology developments in home connectivity, distribution grid intelligence, distributed generation, and broadband over power lines, all of which may interface with the AIM technology.

SCE has developed a detailed strategy and aggressive timeline for the AIM development project that allows for integrated meter design, prototype development, beta production, and pilot test before a new business case would be prepared for Commission approval of full deployment. If there are no major obstacles and the AIM technology delivers its promised improvements to the business case analysis, SCE envisions completing full deployment of the new AIM system no later than one to two years after the time that full deployment of today's AMI technology could be completed. SCE's customers would nevertheless be advantaged, despite this slight delay, given the superior attributes of the proposed AIM technology, including more durability, versatility and the ability to deliver significant improvements in system reliability, customer billing and service options, outage management and operational efficiencies. Thus, it is critical that SCE's ultimate investment in AMI focus on "getting it right" instead of rushing to "get it done."

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I.

INTRODUCTION

This testimony supports Southern California Edison Company's (SCE) Application for Approval of Advanced Metering Infrastructure (AMI) Deployment Strategy and Cost Recovery Mechanism, in accordance with the Assigned Commissioner and Administrative Law Judge's Ruling issued on November 24, 2004.[1] Based on our rigorous business case analysis of the "best" AMI deployment scenarios, we have concluded that an immediate deployment of AMI is not cost effective due to the limited benefits and high cost. Given the limitations of today's AMI solutions, we have developed an innovative AMI deployment strategy to develop the "next generation" of meters to integrate additional cutting-edge technologies to increase functionality and operational efficiencies.

The purpose of Volume 1 is to describe our business vision and deployment strategy for AMI, based on our underlying management philosophy and business case analysis, as required by the Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Framework for Advanced Metering Infrastructure issued on July 21, 2004. This Section I is introductory in nature and describes the organization of this volume.

In Section II of this volume, we discuss our business vision for AMI, including an overview of our proposed deployment strategy for AMI and the necessary steps that must be fulfilled for a wide-scale deployment of AMI to be feasible. This section provides the underlying rationale for this deployment strategy and how our vision for developing an "advanced integrated meter" with multiple times the functionality of today's AMI solutions should resolve many of the challenges uncovered in our business case analysis.

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[1] Assigned Commissioner and Administrative Law Judge's Ruling Calling for a Technical Conference to Begin Development of a Reference Design and Delaying Filing Date of Utility Advanced Metering Infrastructure Applications, issued November 24, 2004.

Our proposed AMI deployment strategy is set forth in greater detail in Volume 2 of the testimony.

In Section III of this volume, we describe our underlying management philosophy that helped shape the development of our business vision and preferred deployment strategy.

Section IV of this volume sets forth a summary of the results of our business case analysis for the best full deployment and partial deployment scenarios using the July 21, 2004 Ruling's prescribed assumptions and parameters. In this section, we summarize the total costs, total benefits, and net present value of each of the two business case scenarios that are described in detail in Volume 3. We also provide our observations on the results of the cost-benefit analysis as they relate to the potential deployment of AMI.

Section V is conclusionary and summarizes SCE's business vision for aggressively developing an "advanced integrated meter" based on our management philosophy and the poor results of the business case analysis of today's limited technology.

II.

SCE'S BUSINESS VISION FOR ADVANCED METERING INFRASTRUCTURE

Our business vision for AMI is to undertake an aggressive process to develop an "advanced integrated meter" (AIM) that can deliver significantly increased functionality and benefits at a lower cost than the best of today's available technologies. Our vision includes significantly improving the cost effectiveness of our AMI deployment business case and resolving many of the key uncertainties that plague our current analysis by integrating currently-available solid-state hardware, meter, and communications technologies to obtain many times the functionality above today's meter capabilities at a potentially lower price. With this vision, we anticipate that a more cost effective and beneficial business case can be achieved than what is possible today, which ultimately is better for our customers.

Based on our thorough business case analysis, it is clear that even the "best" AMI deployment scenarios using today's AMI technology solutions are not cost effective for our customers at this time.[2] From these findings, it is clear that mere "tweaks" to the analysis or to underlying assumptions will not make a substantial difference in the outcome. There are significant challenges to be overcome before AMI can be deployed successfully, including the limitations of today's AMI technology and the level of reliable demand response benefits that could be achieved. We are proposing to address these major challenges so that an AMI deployment will make sense for our customers. To this point, we have not been able to identify a viable AMI deployment strategy using today's commercially-available meters that will provide sufficient quantifiable benefits for our customers.

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[2] *See* Section IV below for a summary of our business case analysis. The details of this business case analysis, including the specific costs, benefits, and uncertainties for each of the scenarios and a discussion of the methodology and assumptions used in preparing this analysis, are presented in Volume 3 of the testimony and the appendices thereto.

This section will focus on how our vision to develop an innovative metering solution that better fits our operations can help overcome the major challenges confronting an immediate deployment of AMI and help maximize potential benefits. Initially, we provide a brief overview of our proposed deployment strategy, followed by a discussion of the challenges that this deployment is designed to overcome.

A. Overview of SCE's Deployment Strategy

We propose to design an innovative metering solution which integrates additional features that will deliver added value and improve the overall business case analysis. By starting with a "clean sheet,"[3] as opposed to attempting to merely modify existing technology with limited and expensive add-on modules, we expect to substantially increase meter functionality at a significantly lower price, while simultaneously increasing future functionality, options for customers to obtain usage data, and the reliability and value of load control and demand response.

This approach is similar to that taken by the Italian utility, Enel. Enel set out to design and build its own meter after determining that its desired level of functionality at an appropriate price did not exist in the commercial meter marketplace. By initiating a "clean sheet approach," Enel was able to integrate selected functionalities into a new meter design rather than attempting to add various modules to an existing meter, resulting in a better end product at reduced manufacturing cost. Although the exact Enel meter design will not work on our distribution system and does not fully suit our specific needs, we believe that the Enel example demonstrates the virtue of an innovative approach to developing a superior, "smarter" meter at a lower cost compared to commercially-available alternatives. Based on recent discussions with embedded system engineers, meter technology vendors and meter manufacturers, we believe we will be able

[3] By "clean sheet" approach, we refer to our strategy to design a meter that integrates additional technologies based on our business requirements, without regard to the functional limitations of merely trying to adapt current meter solutions.

to similarly increase embedded functionality (and associated benefits) and lower the cost to make a future deployment of these next generation meters more cost effective, more versatile, and more functional than any currently-existing alternatives.

Our preferred deployment strategy would be to segregate the AMI deployment process into three phases:

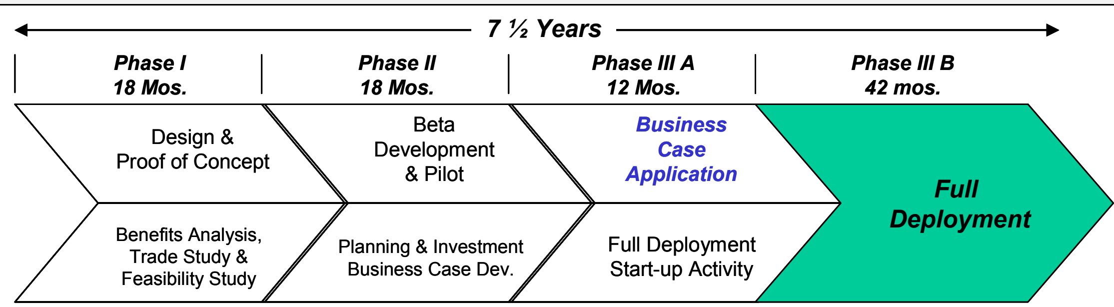
Phase I - Design and Proof of Concept;

Phase II - Beta Testing and Pilot Deployment; and

Phase III - Commercialization and Full Deployment.

As discussed more fully in Volume 2, we would not move forward to the next phase if the goals of the previous phase were not achieved. To be clear, our application in this proceeding seeks authorization only for Phase I and Phase II activities described below. A high level timeline is set out below in Figure 1-1.

Figure 1-1
AIM Project Timeline



Phase I will focus on defining and developing the new meter design from its initial concept to final design and will include the production of working prototypes. As described in greater detail in Volume 2, we propose to engage an engineering design firm to perform the actual design work and other consulting engineers to ensure that the design will in fact meet SCE's business requirements, maximize customer benefits, and be feasible to manufacture at a reasonable price. We estimate that this phase will take approximately 18 months from the time we receive Commission approval. In preparation for this process and in support of this aggressive strategy, we are already conducting market surveys to understand general timing and cost considerations and we are preparing to initiate a formal Request for Information and/or Request for Proposal. At the end of Phase I, we envision submitting a preliminary feasibility report to the Commission providing an update on the design process and expected costs for Phase II.

Phase II will focus on confirming the new product's manufacturability through beta production and on conducting a pilot deployment to field test product functionality and integration with utility systems. Through this beta production and pilot deployment, we hope to uncover any problems early and correct them before ramping up production and mass deployment. This phase will also provide more accurate cost estimates of full production to assist us in preparing a new business case based on the final design of the new AIM system. If no major obstacles are encountered, we estimate that this phase will take approximately 18 months.

We currently estimate we will spend approximately $31 million over the next 36 months to complete the Phase I and Phase II activities. In order to recover these costs, we propose to establish a new balancing account. Similar to other Commission-authorized balancing accounts, the balancing account will ensure that SCE's customers will only pay for the recorded operations and maintenance costs and capital-related revenue requirement ultimately found reasonable by the Commission for Phase I and Phase II activities. Our cost recovery proposal is further explained in Volume 2.

After Phase II, we envision filing a new business case application for AMI deployment based on the costs and benefits of the new AIM. In Figure 1-1 above, we refer to this regulatory interval as "Phase III-A." Provided the analysis for a full deployment of the AIM technology proves to be more cost effective, we expect to begin significant pre-deployment activities during Phase III-A. Upon approval of the business case application, we would then proceed to move into Phase III-B, which is commercial production and deployment of the new AIM system to our customers.

From start to finish, we realistically estimate the entire process from design to the completion of full deployment to take approximately seven and a half to eight years from the time of approval of this application, although it could be more or less depending on whether we encounter substantial obstacles and depending on the timing of regulatory approvals. Although the overall time period for this strategy extends into 2011 or 2012, which is beyond the July 21, 2004 Ruling's desired 2010 completion date, this is an aggressive schedule and will result in a deployment of innovative meters that incorporate proven technologies that can provide increased operational efficiencies and demand response benefits. In the end, despite a slight delay beyond the July 21, 2004 Ruling's original completion date, our customers will be advantaged because we will have deployed the right meter that will be more functional, durable and versatile than what could be deployed today.

B. SCE's Proposed Deployment Strategy Should Resolve The Major Challenges Regarding AMI

There are a number of substantial challenges surrounding an AMI deployment for our customers today, including technological limitations and the unpredictability of reliable and persistent demand response. These primary challenges and uncertainties center on the central cost component (investment in the AMI system and cost to install and maintain) and the central benefit components (operational savings and the avoided cost benefits from demand reductions) of the business case analysis. We have performed statistical analyses to attempt to quantify the uncertainty. On a general level, our analysis indicates that the high degree of uncertainty with the main cost and benefit drivers makes AMI investment too speculative and risky for SCE at this time. An important focus of this proceeding will be to define the challenges of AMI and investigate measures that may resolve or mitigate these uncertainties. We are confident that our proposed deployment strategy will help resolve some of these uncertainties and provide the proper technological scope for a robust, flexible, and more cost effective AMI system deployment.

1. Technological Challenges Must be Resolved Before AMI is Deployed

We find existing off-the-shelf AMI solutions do not support the level of functionality sufficient to support SCE's operational business needs or provide the flexibility for future enhancements without significant retrofit costs. Our findings indicate that an integrated AMI solution that leverages additional commercially-available technologies has the potential to provide an effective platform for increasing operational benefits, enhancing customer energy information, and providing more sophisticated alternatives for load management and routine customer services. The problem is that these enabling technologies have yet to be cost effectively packaged or integrated into a streamlined meter for application in the United States. Given the long life-cycle and significant costs of the AMI metering technology, we believe that it is in our customers' interest to pursue the aggressive development of a new AIM solution that can cost-effectively integrate these additional technologies into the meter itself, thereby increasing functionality and associated benefits at a lower cost.

In short, for SCE, we do not find that the benefits derived from the limited functionality of today's available technology outweigh the relatively high costs thereof. Investing so much money in such limited technology carries a risk of obsolescence given the great potential for developing a smarter meter at a cheaper cost, as proven by Enel's success in Italy. For example, we have determined that based on today's costs and the Commission's prescribed system requirements, the most cost-effective technological solution for AMI would be a RF hybrid network comprised of mesh network for commercial customers and fixed network for residential customers. However, one of the developing technologies or standards, such as residential RF mesh or meters with embedded premise-level communication systems leveraging a standard protocol such as ZigBee, may prove to be more reliable and cost effective, depending on technological advances and economies of scale. If eventually one of these or another technology proves to be a superior and lower-cost alternative to today's proprietary fixed network RF or narrowband power line carrier solutions, there is the risk that an investment in such technologies will become stranded and difficult to maintain. Thus, we hope to mitigate this risk by developing a state-of-the-art meter based on open meter and communications standards that provide a flexible platform for emerging technologies and a wider offering of functionality, ensuring that the new meter technology will be durable and deliver actual benefits for years to come.

Given the attention AMI is receiving and given how quickly the marketplace can adapt to technological innovations (*e.g.*, advances in computers, cellular phone technology, television technology, *etc.*), the possibility that there is a better, faster, cheaper and more reliable technology right around the corner is very real, especially if we engage in a proactive, aggressive process to develop the next generation of meters that can meet our specific business requirements. As such, an additional technological risk is investing in today's technology too soon or at too high a cost. Our proposal mitigates this risk by seeking to develop the "next generation" now. In addition, our proposal mitigates the risk associated with designing a new meter because it will rely on separate proven technologies that will be integrated into one product and because our proposed product development process incorporates a thorough beta production and pilot deployment process to resolve any technological issues.[4]

As described above, there are several technological challenges and substantial associated risks that are further compounded by the fact that the vast majority of AMI technologies available today are each proprietary. This means that none of the existing AMI communication or meter technologies are compatible with one

[4] The July 21, 2004 Ruling's required deployment schedule for the required business case analysis did not allow time sufficient for a staged deployment to work through technological issues, and thus, we would expect high initial failure rates in a deployment of AMI today. In our proposed deployment schedule, sufficient time and resources would be available to test the new product and system integration thoroughly prior to the widescale deployment.

another's systems or components. As such, a failure of a vendor or its technology to perform would mean that another vendor's technology would be required to retrofit the non-performing system. This type of event would create significant negative financial and schedule impact. In our proposed AIM design, we hope to mitigate this uncertainty by creating a design structure that does not rely on proprietary and incompatible systems, but rather uses open standards and flexible design to extend the effectiveness of the technology. In pursuing a more open design with multiple manufacturers, we hope to avoid problems associated with maintaining such systems in the future, when dealing with repairs or obtaining replacement parts.

We believe that load control capability and or compatibility are an integral element for an advanced metering infrastructure. Therefore, another considerable risk is the availability of integrated load control functionality within the communications and meter architecture. Most existing AMI technology solutions, including that selected by SCE as the technology of choice for the business case analysis, do not yet possess commercially available hardware with related embedded load control functionality. Although most of the vendors providing responses to our RFI stated they were willing to explore development with third-party vendors, were currently working on hardware prototypes, or were willing to further explore the issue,[5] there are inherent risks associated with true commercial availability in the near-term. This uncertainty will be resolved through our proposed AIM development project, as this effort intends to proactively integrate additional functionality that simply does not exist in the U.S. market.

In sum, for any deployment of AMI to be successful, the substantial uncertainty about the functionality and cost of the technology currently available must be

[5] Respondents did not provide any details regarding how they plan to achieve these objectives.

resolved. Through our proposed deployment strategy, we believe that these major technological challenges can be resolved or mitigated, to the benefit of our customers.

2. Demand Response Challenges Must be Resolved Before AMI is Deployed

The business case for an AMI deployment will ultimately require actual demand response benefits to be cost effective. Today's meter technology delivers primarily remote interval read capability and does not integrate load control or demand limiting functionality. These load control and demand limiting technologies have the potential to not only help customers respond to dynamic prices or price-responsive programs, but may also provide reliability-based demand response in day-of emergency situations. The potential benefit of such advances is immense and may help resolve key challenges surrounding the reliability and persistence of demand response benefits.

There are issues and considerations regarding customer responsiveness to dynamic pricing that create substantial uncertainty in reliably estimating customer demand reductions in the business case scenarios. These issues and considerations include persistence of the Statewide Pricing Pilot (SPP) results and their applicability to a large scale deployment. Although the SPP observed behavior is the most relevant for estimation of price elasticity in the business case analysis, actual customer behavior could vary significantly according to the prior research.[6] Thus, because an AMI deployment will ultimately depend on demand response that can actually avoid generation costs, it is crucial that the key uncertainties about the reliability and persistence of demand response

[6] The SPP only tested short-run price elasticities. Literature on the subject suggests that long-run price elasticities can be higher than short-run because customers will make investments in response to prices. This is likely to be true, although long-run price elasticities may have little effect on the business case. Long-run effects include customer investments such as insulation or new appliances over a long period of time, especially towards the end of the study period where the impact would be highly discounted in present value. *See, e.g.,* King, Chris, "Summary of Dynamic Pricing, Demand Response, and Advanced Metering Studies," October 1, 2002. Also, Essential Services Commission, Melbourne, Victoria Installing Interval Meters for Electricity Customers – Costs and Benefits, Position Paper, November 2002, pp. 61-67.

be resolved. Through our deployment strategy, we believe that the integration of newer technologies will be able to assist the customer in responding to dynamic rates, as well as potentially delivering load control or demand limiting capabilities for reliability demand response.

Another challenge that exists concerning demand response is that for AMI to be successful, dynamic pricing tariffs must approximate actual market prices, rather than be designed solely to elicit demand response. If rates only approximate actual market prices some of the time and signal customers with wrong prices the rest of the time, there could be perverse and undesirable outcomes. Only real-time retail prices that track wholesale prices in a functioning wholesale market will accomplish that goal. To meet this principle, it is imperative that the uncertainty in the development of a functioning electricity market that is capable of providing appropriate price signals be resolved. Although our meter development proposal does not and cannot fix the market, the timing of our proposal does align itself well with the timeframe in which a functional, transparent market is anticipated to be operational.

The last significant challenge concerning demand response is, as alluded to in the November 24, 2004 Ruling, legislative constraints on rate design modifications that have a considerable impact on the benefits derived from the full deployment of AMI.[7] The legislative constraints result from Section 80110 of the California Water Code enacted by AB1-X as a result of the 2000-2001 energy crisis, prohibiting the Commission from increasing any electricity charge for residential customers' usage of up to 130 percent of the then-existing baseline allowance. This prohibition is in place until the CDWR power contracts expire, which is currently expected to occur in 2013.[8]

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[7] November 24, 2004 Ruling, p. 3.

[8] This sunset is based on the assumption that AB1-X is in effect until the last CDWR power contract expires, which is presently 2013.

As the November 24, 2004 Ruling recognizes, the rate design restrictions required by Section 80110 will impede the ability to derive substantial price responsive demand response benefits under a full deployment in the years prior to expiration of this constraint in 2013.[9] This is because under the statute, rates cannot be designed to elicit response to dynamic price signals for a residential customer's entire usage, given that usage up to 130 percent of the customer's baseline allowance would not be subject to dynamic pricing.[10] Our meter design proposal does not directly affect the applicability of the Section 80110 restrictions. However, given the necessary timeframe to design and develop, test, and deploy the AIM product, we estimate that our AIM deployment would just be completed when these statutory restrictions expire in 2013. Thus, our proposal works well within the realities of the legislative constraints.

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[9] In accordance with Agency Staff direction, the demand response benefit calculations in our business case analysis set forth in Volume 3 have not taken these statutory restrictions into account.

[10] In fact, a residential customer using less than 130 percent of its baseline allowance would never be charged time-of-use or critical peak prices due to the constraints of Section 80110. For SCE, this would include fifty-five percent of its existing residential customer bills.

III.

SCE'S MANAGEMENT PHILOSOPHY CONCERNING INVESTMENT IN ADVANCED METERING INFRASTRUCTURE

In the July 21, 2004 Ruling, the Commission ordered each utility to describe its underlying management philosophy or the business vision used to develop its AMI specifications and approach, including a discussion of how key market factors, regulatory constraints, or internal business constraints shaped or affected the development of its AMI business case.[11] Our recommendation to the Commission in this filing is based on our management philosophy, as explained in this section.

The underlying management viewpoint that has helped shape our analysis and recommendation is consistent with the management philosophy that guides our investment decisions in other areas of the business, namely, *we will pursue investments that are demonstrated to enhance value for our customers, given the likely costs and benefits of the project and in relation to other investment opportunities.* This overarching philosophy also drives our decisions to adopt new technology or processes when it makes economic sense to do so and is beneficial to customers. Thus, the decision of when to invest in AMI technology necessarily involves assessing the impact on our customers and determining whether investing in AMI at this time is in our customers' best interest or whether an AMI investment in the future or on a different scale may be more beneficial to them. This management philosophy has shaped our business case analysis of AMI and has influenced our proposed AIM deployment strategy, which seeks to proactively develop a new meter solution that meets our business requirements on a very aggressive schedule.

[11] July 21, 2004 Ruling, p. 3 ("The analysis the utilities will perform is crucial to the Commission's understanding of the tradeoffs made by the utilities in developing their functional AMI specifications that underlie the benefit cost analysis. In order to enhance this understanding, the utilities should describe the underlying management philosophy or business vision used to develop its functional specifications and approach. Specifically, we are interested in a discussion from each utility of how key market factors, regulatory constraints, or internal business constraints shaped or affected the development of its AMI specifications and cost benefits estimates.").

Our innovative approach seeks to increase functionality to enhance potential benefits at a lower bundled cost compared to today's commercially available solutions.

In concert with this management philosophy, there are two important principles that should help guide the evaluation of whether AMI provides real value to our customers: (1) the investment must be cost effective and deliver actual benefits, and (2) AMI should be consistent with the overarching policy objectives adopted by the Commission.

We demonstrated in our preliminary filings in the AMI rulemaking proceeding that an investment in today's commercially-available technology is not cost effective and delivers too few functions and actual benefits for SCE. Our updated analysis of our best cases further confirms that conclusion. A better approach is to develop alternative, more cost-effective AMI technologies which possess added functionality. We believe we can increase the functionality of today's meters many time over at the same or a lower price. This approach is similar to that implemented by the Italian utility Enel, whose successful design of a new meter with additional capabilities and lower costs was used for its wide-scale deployment in Italy. With this development/deployment strategy, we anticipate that a more cost effective and beneficial business case can be achieved for SCE than is possible today, and will ultimately result in a better investment for our customers, consistent with our management philosophy and principles.

A. SCE Pursues Investments When They Are Cost Effective And Deliver Benefits To Our Customers

We are in a new age of information and technology which offers great promise in many areas of our business. We know from the dot-com boom/bust cycle that there are many more ideas than there are actual profitable ventures. The pace of change is so rapid that it is simply not feasible to immediately adopt every technical improvement that comes along. The question of whether and when to upgrade technology must look beyond the current generation of technology and anticipate even further technological improvements. By applying this principle, we have and continue to make cost-effective technology improvements and upgrades in many areas, including metering.

Our proposed AIM will couple the effectiveness and efficiency gains of new technology with the benefits of peak load reductions. For years, we have relied on cost-effective reliability-based demand response programs[12] to serve an important role in meeting our customers' capacity needs. We are confident that an improved AMI can support various approaches to help balance California's electricity supply/demand equation, including not only reliability-based programs, but also dynamic pricing,[13] market/economic-triggered demand response programs,[14] and/or demand-limited programs.[15] We believe that innovative, cost-effective technology that can meet our needs is within our grasp if we simply set forth to integrate these proven technologies into one, open platform.

We have evaluated the two best AMI business cases required by the November 24, 2004 Ruling by the same standards as we use to evaluate other ratepayer investments of a similar magnitude. This work demonstrated where the incremental benefits of AMI fall short for SCE and provided direction on where we may be able to develop a cost-effective solution for our customers.

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12 By "reliability-based demand response," we refer to demand curtailment programs that do not have a price-responsive element and instead are activated upon system emergency, such as the interruptible or direct load control programs.

13 By "dynamic pricing," we refer to tariffs that enable electric customers to respond to a signal of actual costs or market prices, such as time-of-use or critical peak pricing.

14 By "market/economic-triggered demand response," we refer to load curtailment programs that can be activated in response to market prices, such as the demand bidding program.

15 By "demand limited programs," we refer to tariffs that limit customers to fixed levels of demand during critical peak periods by "ratcheting" down their available electricity.

1. SCE Pursues New Technology and Processes that Provide Increased Operational Efficiency

SCE constantly assesses the potential for improving operational efficiency and evaluates new processes and technologies that have demonstrated the ability to deliver benefits to our customers through enhanced services or lower costs. We are on the forefront in utilizing automated processes and adopting technology where it is economic to do so based on operational efficiencies or process improvements. Today, we already read more than 500,000 meters remotely through our Automated Meter Reading (AMR) program, which targets those meters that are the most difficult to access and most expensive to read. We also have a long and extremely successful history of developing automated load control programs, such as the highly successful air-conditioner load control program, which continues to deliver very reliable and cost-effective demand curtailment. Moreover, we have helped innovate new uses for technology to improve demand response programs, such as testing and supporting the development of smart thermostats and other technology to provide pricing information to our customers.

In addition, we have already made significant investment (and continued investment) in highly-effective automated systems that help system operators better understand load and demand requirements. SCE continues to improve automation and data communications for its substation operations with Intelligent Electronic Devices (IEDs) that communicate through a Local Area Network to our Supervisory Control and Data Acquisition (SCADA) System. This modern protection and control equipment provides remote, self monitoring control of all substation functions, identifies potential problems, and allows a quick response to reliability events.[16] We have already invested in highly effective outage management and transformer load management systems that are

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[16] Among the many types of automation and sophisticated electronic equipment for our substations and operations network are satellite communications for substation data collection and remote system control in areas where conventional methods of communication are not available or are too costly.

delivering real operational benefits to our customers today. As these investments show, consistent with our management philosophy, we embrace technology when it makes sense to do so operationally and when it can reduce costs and provide real value to our customers.

Having already made investments in these successful operational systems, we are already reaping the benefits that these systems deliver and will continue to deliver, even without an immediate deployment of AMI. Given that we already derive many of these benefits, additional investment in today's AMI technologies may not result in significant additional value to SCE from these types of operational benefits. However, as noted above in Section II and in Volume 2, we expect that by incorporating additional components into an open meter and communications platform, we will be able to increase the level and type of benefits that AMI can deliver.

We recognize that technological innovation is a constant and never-ending cycle. We also recognize that economic efficiency requires flexibility to adopt technological changes as they occur, as well as the careful consideration of the optimal time to invest. Thus, one of the essential questions in this proceeding is whether a large-scale investment in the AMI technology of today will maximize benefits for SCE's customers or would such investment now end up costing our customers more due to today's less capable technology and the lost opportunity to capitalize on improved and/or less expensive technology in the near future. There are promising technological advances that present the unique opportunity to work to integrate solid-state technologies in the near term that can increase meter functionality at a reduced price. These increased metering capabilities may provide additional operational efficiencies and far more reliable benefits than are possible from existing AMI technology, which will ultimately be a better investment for our customers. In addition, by developing a new meter with an open meter and communications design, it will be more flexible with "plug and play" capabilities and will be more versatile and extensible for technology advances in the future, such as broadband over power line.

2. Demand Response Resources Must be Cost Effective in Relation to Other Resources

Our business vision regarding AMI takes a comprehensive view of demand response versus other resource options. Although demand response offers the potential to reduce peak load, the fact remains that demand response from time-differentiated rates ultimately relies on customer behavior. This "behavioral" aspect makes dynamic pricing demand response more uncertain than other resource options, including, among others, supply-side resources, permanent installations of energy efficient equipment targeted at reducing peak consumption, and dispatchable load control programs. Generally, these other resources are more permanent and have much greater reliability over the long term than price-responsive demand response resources, which continue to be subject to economic, political and behavioral changes.[17] Specifically, for demand response resources to be valued as high as supply alternatives, they must provide equivalence in key attributes such as reliability and flexibility.

The role and success of other resource options, as well as the overall market, may directly affect the economics of whether AMI is the right investment to make for our customers at this time. For example, major regulatory changes to the status of direct access, community choice aggregation, or the introduction of a core/non-core market structure could completely alter the assumptions of how many customers would continue to be utility customers subject to time-differentiated rates, especially if higher rates were required to fund the cost of AMI. This is an important issue because non-utility customers

[17] For example, during the 2000-2001 energy crisis, customers responded to the crisis by reducing their electrical usage, but gradually, these reductions have waned as customers return to their old usage patterns. Reductions from customer behavior, as opposed to load control or permanent energy efficiency equipment, will always be less predictable and reliable and will take continual customer education and marketing to keep informing and reminding customers of the desired behavior.

will be subject to the generation pricing of their energy supplier who has no obligation to offer dynamic electricity pricing structures. In addition, major changes in the wholesale electricity market, including the role of the Resource Adequacy Requirement, will directly influence the cost effectiveness of AMI.[18]

B. AMI Should Be Consistent With Overarching Policy Objectives Adopted By The Commission

AMI is a substantial investment in the power delivery infrastructure that will affect a wide-range of business activities and customer services. In addition to enabling time-differentiated pricing for all customers, AMI may offer ways to enhance system reliability, customer billing and service options, outage management and operational efficiencies. So far, the context of this proceeding has been centered on the Commission's vision for the future that includes preference for energy efficiency and demand response. The Commission's intent with this preference is summarized by an earlier ruling in this proceeding, which stated:

> "This vision is intended as a broad statement for encouraging demand responsiveness in California. It should be read in the context of maximizing the efficient use of resources, while maintaining the economic vitality of businesses in the state, as well as the health, welfare, and comfort of residential electricity users."[19]

AMI is a means for accomplishing objectives that include demand responsiveness and maximizing the efficient use of resources, but it should be done in recognition of broad overarching policies of economic welfare. In addition to operational benefits, AMI should deliver reliable demand response that does not sacrifice the comfort of residential customers.

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[18] The development of a functional energy market is an important unknown that must be resolved before price-responsive demand response can be truly effective.

[19] Administrative Law Judge's Ruling Seeking Comment on Vision Statement, R.02-06-001, issued on November 29, 2002, Item 3, p. 1.

1. AMI Must Deliver Reliable and Persistent Demand Response Benefits

The success of AMI is greatly enhanced by realizing benefits from *reliable* demand response, whether that be achieved from integrated load control on end-use devices inside the home, at the meter itself, and/or through dynamic time-differentiated rates. Assessing the value of these benefits requires the consideration of whether these types of resources will reliably lower the peak demand and avoid the cost of additional generation capacity and energy purchases.

As described in Volume 2, we expect that load reduction technologies can be integrated into the meter itself, thereby providing the means for effective and efficient load control programs that can deliver reliable demand response when necessary. Moreover, this technology may also be used in combination with dynamic pricing tariffs to help customers better respond to pricing signals. Thus, with more advanced technology integrated into the meter, we are striving to increase the level and reliability of load control and demand response.

For price-induced demand response programs to be truly effective (both in short-term emergency situations and in affecting the overall demand curve and market prices in the longer term), the price signals must be cost or market-based, rather than simply created to produce a predetermined response. As a general principle, economic efficiency is promoted when customers make decisions based on current costs that reflect the actual economic impact of their decisions. It is also a matter of economic efficiency that rate components reflect their underlying cost structure. A customer's decision to increase the thermostat setting or otherwise reduce or defer energy consumption becomes the optimal economic decision when rates reflect the actual costs avoided.

In addition to being cost-based, dynamic pricing rates should provide a sufficient bill reduction when customers reduce or shift electricity usage to low-cost hours. Many customers could "lose" on dynamic rates, with higher bills despite the same or even reduced demand levels.[20] This bill impact analysis is troubling because most customers who significantly alter their behavior will only see minimal bill savings – and many customers will actually see *increased* bills. Such little reward – or negative bill impact – creates customer dissatisfaction and can create a backlash to dynamic pricing tariffs. Experience tells us that customers who have a negative experience will be less likely to choose to participate in future demand response programs.[21]

We realize that important work still needs to be completed before a true "market" price will be readily accessible. It is unclear in what form capacity pricing will be reflected in the electricity market and how the Resource Adequacy Requirement will affect the volatility of energy prices in that market. Nevertheless, it is important that dynamic price signals mirror actual costs as closely as possible so that efficient demand response programs can be implemented. Thus, to the extent AMI relies on actual demand response benefits from price-responsive programs, it will be imperative that a functional wholesale market is operating from which we can develop appropriate cost-based retail rates.

2. Customers Should Be Informed And Allowed To Make A Choice

Our business case analysis establishes that an AMI deployment at any level will ultimately depend on significant and reliable demand response benefits to justify the cost. Ideally, we believe that the AMI business case should be cost effective based on operational savings and realistic assumptions of demand response from voluntary tariffs.

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[20] For example, our analysis of critical peak pricing shows that 13% of residential customers will likely see a bill increase of 10% or greater, even though they reduce their usage during CPP events on critical peak days by 20%, while only 16% of customers will see a bill decrease of at least 10%. *See* Appendix K.

[21] This potential outcome is similar to what happened to the Puget Sound Energy demand response program in which the customer bill reductions were relatively small despite significant customer behavior changes. Once customers realized they were saving so little or even paying more despite significant effort to reduce demand, they opted out of the program in large numbers, leading the utility to cancel the program altogether. *See* Williamson, Craig, "Primen Perspective: Puget Sound Energy and Residential Time-of-Use Rates – What Happened?," Energy Use Series, Volume 1, Issue 10, December 2002.

To the extent demand response benefits play this key role in the AMI cost benefit analysis, the Commission must be willing to put the appropriate policies in place to ensure that the required levels of demand response are realized. Given the size of the gap between the costs and operational benefits, achieving significant and persistent demand response would likely require that all customers take service on a tariff involving time-differentiated rate structures. We anticipate that with our proposed deployment strategy to increase benefits and lower costs, we can narrow this gap and reduce the dependency of the business case on demand response benefits, and hence, the need for mandatory dynamic pricing. In addition, by a significant increase in the functionality of the meter, we expect to embed technologies (such as load control, demand limiters, and communications for in-home display) that will facilitate customers' demand reductions, provide them with choices of tariffs and control technologies, and improve the reliability of demand response.

IV.

SUMMARY OF BUSINESS CASE ANALYSIS

The July 21, 2004 Ruling required that we perform at least seventeen unique business case analyses involving various operational and demand response scenarios for our preliminary analysis. For this final analysis, the November 24, 2004 Ruling directed us to present the best full deployment scenario and best partial deployment scenario. In reviewing the business case analysis, we determined that the best full deployment[22] and partial deployment scenarios[23] involved a default CPP rate without reliability.

The July 21, 2004 Ruling's requisite analysis parameters included the assessment of uncertainty and risk in both a quantitative (such as with Monte Carlo simulation techniques) and qualitative manner.[24] We have done both. We prepared Monte Carlo simulations of the cost parameters and the demand response benefit elements to derive a range of results and an expected value.[25] The method employed is described in Volume 3, as are the quantitative results and a qualitative assessment of risk factors. We have taken great care in evaluating both the cost and benefit side of the business case and applied a net present value of cash flow method, as we do for other types of utility investments. We employed the framework and assumptions required by the Ruling but supplemented the analysis with a discount rate and other key assumptions consistent with investments of a similar long-term nature.

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[22] This was Scenario 4 from our January 12, 2005 Preliminary Analysis.

[23] This was Scenario 17 from our January 12, 2005 Preliminary Analysis.

[24] July 21, 2004 Ruling, pp. 12-13.

[25] The Monte Carlo simulations were performed and the results of these simulations are presented in Volume 3 and discussed in Appendix E.

A summary of the revised costs, benefits, and Net Present Value (NPV) on both an after-tax cash flow and a revenue requirement basis for each of the best scenarios is presented below in Table 1-1.[26]

Table 1-1
Summary of AMI Business Case Analysis
(in millions 2004 Present Value dollars)

No.	Scenario Description	Rate Details	Total Costs	Total Benefits	After-Tax NPV	Rev. Req. NPV
4	Full Deployment Operational + Demand Response	CPP-F/CPP-V Default with 20% opt-out	$(1,298.4)	$804.6	$(402.8)	$(951.8)
17	Partial Deployment Operational + Demand Response	CPP-F/CPP-V Default with 20% opt-out	$(164.2)	$77.7	$(60.9)	$(129.9)

As indicated above, neither of the best deployment scenarios establish that an investment in today's AMI technology is cost effective using the Ruling's required assumptions. The case with the least negative NPV case is Scenario 17, which includes dynamic pricing on a default enrollment basis for a partial deployment and limited AMI deployment to certain customers within Climate Zone 4 that contains the hottest, desert areas of our service territory. Yet, even this "best" scenario has a negative present value of $(60.9) million, and a negative revenue requirement impact of nearly $(130) million (2004 present value).

These results are at the optimistic or high-side of the spectrum of outcomes. In both scenarios, demand response benefits contribute significantly to total benefits which are calculated based on the November 24, 2004 Ruling's assumptions for valuation of those benefits which we believe are too optimistic. When we correct for the limitations of ability to call a CPP event, demand response benefits are cut almost in half, as discussed in Volume 3.

[26] The details of this business case analysis, including the specific costs, benefits, and uncertainties for each of the scenarios and a discussion of the methodology and assumptions used in preparing this analysis, are presented in Volume 3.

We also considered the effects of the lost value of service to customers from the imposition of high peak prices. When customers forego usage they enjoy at today's prices, the procurement saving benefits obtained from lower usage at new prices are offset by the customers' loss of comfort and convenience. We calculated this benefit offset but did not include them in the tables above.[27]

Further, we caution the Commission against viewing the results of the partial deployment scenario as simply less unfavorable than the full deployment result. In relative terms, the partial deployment case is worse than the full case in many significant respects. Importantly, the negative NPV as a percent of investment cost is much higher in partial deployment than in the full deployment case. This is because the cost of infrastructure is higher in the partial case on a per meter basis because fixed costs are spread over fewer participants than in the full case.

For an AMI deployment to have a positive NPV, either costs must decrease and/or benefits must increase substantially compared to today's business case. A proactive and aggressive effort is needed to develop cost-effective technology that delivers an integrated metering solution to gain additional operational efficiencies unique to SCE and significant reliable demand response.

Given that the November 24, 2004 Ruling's required business case analysis using today's technology results in a significant negative NPV, even using highly optimistic assumptions, it is clear that the existing AMI technology is not a prudent investment for our customers at this time. However, we have identified many additional functions that could be incorporated into an integrated AMI system to provide SCE greater operational and demand response benefits. As described above, we are optimistic that we can undertake an aggressive deployment strategy to develop a new advanced integrated meter that can deliver increased operational efficiencies and yield additional benefits at a lower

[27] *See* Appendix J.

bundled cost, thereby making this alternative AMI investment a more prudent approach for SCE compared to an investment today in currently-available off-the-shelf AMI technology.

V.

CONCLUSION

Our business case analysis illustrates that without substantial modification, all of the AMI deployment scenarios under the July 21, 2004 Ruling's required assumptions are far from being cost effective. The results establish that an imminent deployment of today's AMI technology – as envisioned in the July 21, 2004 Ruling's framework – is not cost effective or reasonable from the customers' perspective. SCE's proposed deployment strategy would first seek to resolve the major challenges surrounding the AMI business case by developing better technology at a lower cost, while increasing operational, demand response and customer benefits. With the development of the "right" metering solution, it is likely that a future deployment of AMI will achieve the types of durable benefits and customer value that today's technology cannot deliver. Even though our development strategy may slightly delay the overall timing of a full deployment than if today's technology were installed now, our customers would nonetheless be advantaged because our new AIM system would deliver more benefits and would be more functional and adaptable to future technology. Ultimately, AMI may be a good investment for our customers if we are willing to work to "get it right" instead of rushing to "get it done."

Application No.:	A.05-03-
Exhibit No.:	SCE-2
Witnesses:	D. Berndt P. De Martini L. Letizia

SOUTHERN CALIFORNIA EDISON

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(U 338-E)

Testimony Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism

VOLUME 2 – Technology and Market Assessment, Deployment Strategy, and Cost Recovery Proposal

Before the

Public Utilities Commission of the State of California

Rosemead, California

March 30, 2005

Volume 2 – Technology and Market Assessment, Deployment Strategy, and Cost Recovery Proposal

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I.

INTRODUCTION

The purpose of Volume 2 is to provide a detailed discussion of our preferred AMI deployment strategy, given the state of existing meter technologies and the metering marketplace. As set forth in Volume 3, deployment of currently-available AMI technology is not cost effective for our customers, given the limited functionality and operational benefits this technology provides. As such, we propose to undertake an aggressive strategy to design and develop the "next generation" of meters that will have several times the functional capabilities of today's technology at the same or lower cost.

Section II of Volume 2 assesses existing meter technologies and identifies technological challenges that must be resolved before wide-scale AMI deployment will make sense for our customers. This section also provides a detailed assessment of the current meter marketplace and discusses existing barriers that must be overcome before a newer AMI technology is developed that provides more functionality at a lower price than today's AMI technology.

Section III of this volume details our preferred AMI deployment strategy. This strategy uses a phased approach to custom design a meter that integrates additional functionality to increase added value and improve the overall AMI business case analysis. By using a "clean sheet" approach to design a workable AMI solution – rather than attempting to modify the existing technology with add-on modules – we are confident that we can significantly increase meter functionality at a lower price. The staged approach to our design, development, and deployment strategy is discussed in Section III.

Section IV of this volume sets forth our cost recovery proposal for the costs incurred for the first two phases of our deployment plan as described in Section III.

II.

CURRENT TECHNOLOGY AND MARKET ASSESSMENT

A. Technology Overview

This section describes our assessment of current AMI technology, metering marketplace characteristics, and key vendor capabilities. The primary focus of this proceeding has been to determine whether deployment of advanced metering technology is a cost-effective investment for California's utility customers, given the costs and benefits of this technology. Throughout the course of this proceeding, we have engaged in a thorough process of assessing and understanding the potential capabilities and benefits that can be obtained from advanced technologies for metering, load control, and customer information displays. We have had the opportunity, both in preparing the business case and in participating in Working Group 3 efforts and in the Statewide Pricing Pilot (SPP), to evaluate and analyze the current AMI technologies and their potential operational and demand response benefits. The clear result of this analysis establishes that, given SCE's starting point, the cost of today's technology significantly outweighs its benefits. Although today's AMI technology may make sense for other utilities, the incremental value provided by such technology to SCE is more limited, given our previous investments in technologies such as automated meter reading (AMR) and outage management systems (OMS). Thus, until AMI technologies can provide substantially more benefits at lower cost, an investment in AMI will not be cost effective for our customers.

While assessing the value of today's AMI technologies, SCE discovered that promising developments are on the horizon. For example, the Italian utility, Enel, has experienced much success in designing and developing a new meter that integrates many new meter functions which increase operational benefits and lower costs. Our analysis indicates that an aggressive and dedicated effort to custom design a meter that integrates proven technologies into an open design, multifunctional platform can lead to a significant increase in functionality at the same or lower cost than that of today's limited technology.

In focusing on developing the "next generation" meter, we anticipate that we can greatly improve the cost effectiveness of the AMI business case.

Our next generation "Advanced Integrated Meter" (AIM) is expected to leverage commercially-available components through a meter and communications open design to provide a flexible and sustainable technology platform during the meter's long lifecycle. This approach makes sense given technology developments in distribution systems management, home connectivity, and broadband over power line. As such, we must be able to integrate enabling functionality beyond interval meter reads and two-way communications to include: (1) remote connect/disconnect and demand limiting, (2) home area network integration, (3) power quality metrology, and (4) ancillary components such as Radio Frequency Identification (RFID). Through this integration, operational and demand response benefits could be gained from the increased functionality. Our research has revealed that significant efforts are underway to create an open robust standard for home automation and controls. Two of these technologies include ZigBee and Z-Wave. With these types of interfaces, it is easy to envision a more sophisticated and dynamic demand response interaction with customers whose electrical appliances or equipment can be connected or interface with an AIM-type infrastructure. There are also opportunities to extend our existing distribution grid monitoring systems (*e.g.*, Outage Management Systems) beyond the current primary distribution monitoring and control points to the secondary systems and meters. Meters with power quality and directional power flow measurements, for example, could bring material improvement to our distribution planning, operations, and customer service response.

Much of the functionality is not available today in a packaged solution that meets our unique operational needs to reduce costs and increase benefits. In the few instances where it is available, it is typically packaged as add-on components to existing meters and is offered at much higher costs. Lowering the cost of an integrated package of capabilities requires an aggressive and focused development effort, similar to the approach used by the

Italian utility, Enel. Our discussions with existing manufacturers indicate that current solid-state electronic meters can be enhanced to integrate much more functionality and, with the production volume over 4.5 million units for SCE, lower meter prices can be achieved to levels comparable to the cost of current AMI meter solutions. Our research to date confirms that achievement of this goal is within reach because the desired components not only exist, but the industry is willing to work with us to develop an integrated meter solution. We are confident that our proposed deployment plan can achieve a new integrated design based on an open-standards communication platform that can be developed, tested, and installed within a reasonably quick timeframe.

B. Technology Assessment

In an Assigned Commissioner and Administrative Law Judge's Ruling issued on February 19, 2004, the following six key functional requirements for an effective AMI solution were identified:

(1) Support dynamic tariffs;

(2) Provide customers with access to usage data;

(3) Flexibility in data access frequency (without additional hardware costs);

(4) Compatible with applications that utilize collected data;

(5) Compatible with utility system applications that enhance system operating efficiency and improve service reliability (including outage management); and

(6) Capable of interfacing with load control communication technology.

Our AIM product would certainly be designed to meet these requirements. Moreover, going beyond these high-level functional attributes, we envision additional features that will dramatically improve the economics of deploying an effective AMI solution. We have identified the key features we intend to evaluate as follows: (1) demand limiting capability to remotely reduce kW demand, (2) remote connect/disconnect capability to reduce the number of required field visits, (3) two-way communications to later customers of pending critical peak conditions, and (4) standardized data communications protocols to allow the use of multiple meter vendors who can provide a standard product meeting SCE's download communications specifications.

Although separate technologies to support these key functions may currently be commercially available in the marketplace, these technologies are not available in an integrated meter package and are not cost-effective for deployment today, as they are only available with the separate add-on module often costing more than the meter itself. In the few instances where certain functions have been combined, the meter configuration was designed for a limited number of applications. Even though there are numerous deployments of advanced electronic metering with interval data recording capability across the country, none of the deployments provides the key operational capabilities identified above. In our assessment of currently-available AMI technologies, including a rigorous Request for Information solicitation and market surveys, we did not find a proven and comprehensive metering solution that would meet the Commission's and SCE's requirements. Today's available solutions either lacked proven demand response interfaces, could not provide direct connect/disconnect functions, or did not provide an open communication protocol to allow for the use of more than one meter vendor.

The metering industry is established and the technology generally follows opportunities in the market for AMR – and now AMI – which in today's marketplace are generally defined as interval data recording capability through minimal, one-way communication. Load control communication, customer information displays, and other functions such as remote connect/disconnect are generally only available with add-on components. Of course, adding modular add-on components to the physical meter increases the final cost of the system, higher failure rates, and associated operational and maintenance expenses. Simply put, the market has not yet developed a comprehensive metering solution that integrates proven technologies which cost-effectively deliver key functionalities that will provide reliable, demand response benefits and significant operational savings unique to our system needs.

We are confident that the potential exists for such solutions. All that is needed is a comprehensive approach to meter design that incorporates these various technologies into one streamlined package. Notably, today's marketplace faces two challenges to near-term development that must be overcome. First, a comprehensive packaged solution with additional functionality must be provided at low cost. Such functionality should include the key operational features described above. Second, to the extent possible, both the meter and communication solution should be based on open standards. Such standards will enable functional extensibility and facilitate competition among vendors who provide metering components. Currently, the meter marketplace does not meet these requirements at a cost-effective price.

1. Current Market Dynamics and Opportunities

There are several characteristics of the advanced meter market and the utility industry that have generally precluded the introduction of a metering solution that delivers a broad rage of functionality at a competitive price. For the most part, utility demand has primarily centered on AMR solutions where deployment is justified by the reduction in manual meter-reading labor costs.[1] Limited demand for more robust, AMI-type solutions has created unfavorable market conditions for vendors, resulting in limited budgets with a low risk tolerance for new product development. Based on our market surveys and discussions, we understand that vendors are interested and willing to develop new products if funding becomes available or if there is more certainty in market demand.

Currently, many utilities are using basic first and second generation AMR technology. For example, we have deployed more than 500,000 AMR meters to date. The

[1] In this Exhibit, AMR refers to drive-by collection of monthly reads; AMI refers to higher frequency of usage data collection (at least every day) and two-way communication between utility and meter.

purpose of that deployment was primarily to capture benefits associated with reducing the costs of what were high-cost-to-read or difficult to access meters. As a result of the market demand for AMR technology, the meter vendors produced meters that met both the functional and economic needs of utilities. Vendors were able to identify profitable and attainable opportunities and obtained the necessary research and development (R&D) capital to develop the solutions that utilities desired. More recently in California, RTEM development has set the standard that defined the capability of today's meter and communication systems. However, the existing RTEM meters do not include the open communication protocol we envision for the next generation of meters.

Until more utilities seek to deploy comprehensive, integrated AMI solutions, we believe there will not be a strong incentive for the meter manufacturers and solution providers to notably improve upon existing AMI functionality and cost on their own. Although positive movement in the AMI industry is on the horizon, most of the large-scale implementations appear to be outside of the U.S. Significant AMI deployments are planned in Canada, Australia, and Europe. These deployments, however, do not aim to meet the same requirements that the Commission has set forth for AMI, nor do they include the more robust features we require. Furthermore, most of the deployments are on much longer timetables than the schedule originally envisioned by the Commission. The Chartwell 2004 AMR Report explains that AMI is "the area that many vendors are focused on and the pace at which utilities install advanced metering will likely dictate the future growth of the industry."[2] In other words, the metering vendors are not expected to lead innovation; instead, the market will follow the utilities' lead.

Due to these market dynamics, we do not expect the market alone to produce an affordable AMI meter with the necessary functionality in the foreseeable future. Vendors require a significant increase in AMI demand before they will incorporate

[2] Chartwell, *The Chartwell AMR Report 2004,* September 2004.

additional functionality and create new products at lower cost. A catalyst is needed to accelerate the market to a level at which a cost-effective AMI solution can be produced that provides the maximum number of features which can be used by the utility and its customers. Our AIM development project is that catalyst.

2. State of Today's Current Meter Marketplace

AMI metering and component vendors primarily serve niche markets or "market segments." Vendors and solution providers generally offer specific services in one or two market segments, such as meters, load control devices, or communication infrastructure. Figure 2-1 provides the four primary market segments in the meter market and a sampling of the many vendors active in the AMI equipment industry. The information in Figure 2-1 shows that most vendors are active in only one or two of the four market segments. This specialization is confirmed in an article from Energy Probe.org that shows that most utilities that use AMR or AMI "rely on more than one AMR technology for data collection."[3]

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[3] Adams, Tom and Stanbury, Allen, "Electricity Metering Options for Ordinary Customers in Competitive Electricity Markets," www.EnergyProbe.org, April 12, 2002.

Figure 2-1 Sample Vendors in AMI Market Segments	
Electric Meters *Itron/Schlumberger *Landis + Gyr *Elster *GE	***Data Collection & Communications*** *Itron *Elster *DCSI *Silver Spring Networks *StatSignal *Tantalus *CellNet
Load Control Devices *Corporate Systems Engineering *Cannon Technologies *Comverge *Honeywell *DCSI *Landis + Gyr	***Ancillary Devices*** *BPL (disconnects) *USCL (in-home display) *BlueLine (in-home display)

The fragmented nature of the marketplace requires utilities to purchase individual components from different suppliers to achieve the full menu of desired benefits, thereby adding to overall costs. For example, load control and ancillary devices, such as remote connect/disconnect, are not currently available as an integrated feature of reasonably-priced meter solutions.

An obstacle to building a sustainable technology platform is the nature of the communications and data management software and technologies that rely on unique and proprietary protocols. Because the marketplace has not yet demanded a comprehensive solution that relies on open architecture and standards, the “next generation” meter that integrates additional functionality has not yet been developed. In a study for the Ontario Energy Board in Canada, the Municipal Utility Telecommunications Companies discussed the abundance of proprietary technology and lack of standards as challenges to AMR/AMI implementation and pointed out that “[t]he current state of standards and interoperability would seem to force [Ontario] to choose between a single-vendor approach and an alternative that sees disparate technologies sprouting in isolated islands…."[4] The American Meter Reading Association sees little acceptance or standardization of AMR metering devices, even after 12 years of working on ANSI C12.19, a standard for organizing AMR data.[5]

This is not unusual in any technology development where patents and intellectual property protections are necessary to reward innovation. At a reasonable point of technological maturity, open standards can greatly advance the applicability of innovations. The following examples illustrate the advances in wireless home area network technology and reference design development. Z-Wave is one new standard of automation technology focused on in-home control capabilities backed by Denmark's Zensys Inc. It includes readily developed products from such companies as Leviton Manufacturing (lighting and other control switches), Intermatic (timing and control devices, switches, *etc*.), and Wayne Dalton (garage door openers). ZigBee is another standards-based architecture which adds logical network, security and application software to a physical radio spectrum specified by the IEEE 802.15.4. The ZigBee Alliance is an association of companies working together to enable reliable, cost-effective, low-power, wirelessly networked, monitoring and control products based on an open global standard. This alliance includes Honeywell International, Itron, DCSI, Motorola Inc., Intel and Hewlett-Packard. Many of the ZigBee affiliated firms are already incorporating this technology in a wide range of commercially-available (or soon to be available) products and applications across consumer, commercial, and industrial markets worldwide.

These technologies offer excellent platforms for in-home local area networks to send and receive information, and to monitor and control appliances. Additionally, the cost of this technology is within reach. For example, ZigBee based chips are commercially

[4] Municipal Utility Telecommunications Companies, "Smart Meter Initiative – Further Consultations" (Board File No. RP-2004-0196), www.oeb.gov.on.ca.

[5] Seger, Paul H., "When Will We Have Integrated Metering?" *Gas Utility Manager,* June 2003.

available today at unit prices well below $3 per unit for the volume associated with full deployment within our system. The expectation in the market is that unit prices will very soon reach $1 or less, making it a potentially ubiquitous technology integrated into any new major electric appliance. As a result, this type of technology has the possibility of providing a gateway into and around the home for highly interactive and intelligent demand response.

C. Overcoming Market Challenges

We are confident that the market barriers and obstacles discussed above can be overcome, resulting in the development of a cost-effective AMI solution that will allow us to provide additional benefit to our customers. The concept of a utility working to design its own solution in lieu of adopting available AMI technology is not unprecedented. Starting in the late 1990s, the Italian utility, Enel, faced similar market and technology conditions as it looked to solve its business needs with an advanced meter solution.

In 1999, Enel realized that in order to create an acceptable metering solution, it would need to fund and drive the product development process itself by working with AMI technology manufacturers and vendors to develop a customized meter solution integrating remote interval data collection, full two-way communications, text messaging capabilities displayed at the meter (a large percentage of meters are located inside the home), demand limiting and remote connect/disconnect to support contract demand tariffs, and non-payment management, at a unit price of less than USD $80.00. As such, Enel coordinated the design of a meter to meet its business requirements and then contracted the manufacturing, testing and installation of what will ultimately be a 30 million meter deployment. Although there are aspects of the Enel business case and deployment approach that are not applicable to SCE's circumstances, the Enel example demonstrates that it is feasible for a utility, in conjunction with qualified experts, to successfully design, develop and deploy an AMI metering solution that meets its business needs when the current meter technology cannot. In addition to the ability to integrate additional functionality and incorporate open-platform architecture to extend the technology lifecycle, we understand from our initial market surveys and discussions that similar prices to what Enel achieved in Europe are feasible in the U.S. The bottom-line is that we can develop a meter design that increases functionality by several times, is built on an open platform that is adaptable to future technology innovation, and can be manufactured at a price near our average meter cost today.

1. Overview of Enel's Experience

Enel's AMI solution is called the "Telegestore System" and is the most extensive advanced metering deployment in the world to date. Enel's primary goals in implementing AMI were to improve its operational efficiency and effectiveness in preparation for the liberalization of the European electricity market and to improve its level of customer service.[6]

Enel partnered with a leading design firm to design three physical meters (one monophase and two polyphase) and a different vendor to integrate its power-line carrier (PLC) technology into the utility's remote metering management project. The partnership with the two vendors provided Enel with AMI system skills and expertise, while supplying the vendors with the necessary R&D funding to design a new meter and infrastructure to meet Enel's operational needs. Because Enel had been experimenting with variations of AMI since the mid 1990s, it took approximately 18 months to develop and design the meter specifications, build a meter prototype, and test the prototype to ensure that it could be manufactured on a large scale.

To manufacture the new meters, Enel procured all the necessary materials from more than 50 suppliers and set up assembly plants in Italy, China, and the Czech Republic. These combined manufacturing resources enabled Enel to produce up to 50,000

[6] Although we advocate following the successful example of Enel in developing a new, integrated meter using a "clean sheet" approach, our end solution will be significantly different than Enel's design due to key operational differences.

meters per day. The utility hired external contractors to install meters at a rate of 700,000 per month. The installation of all 30 million meters is expected to be completed in 2005.

The Enel meter has several unique functional components embedded within it. These allow the utility and its customers to reap many benefits. Some of the key features of the Enel metering solution include:

- Remote meter reading/polled on-demand;
- Ability to limit demand to contract levels;
- Remote management of customer service contracts (voltage change, tariff change, connect/disconnect, service [contract demand] level);
- Remote monitoring/continuous service monitoring;
- Supply loss information is recorded at the meter (time and duration);
- Text messaging capabilities;
- Time-of-use (TOU) pricing;
- On-board anti-tamper system; and
- Customer pre-payment for service enablement.

Figure 2-2 highlights the utility and customer benefits enabled by the increased AMI functionality.

Figure 2-2
Benefits of Enel AMI Solution

Enel Benefits	***Customer Benefits***
*Improved operational efficiency through: *Reduced energy loss/fraud *Improved forecasting *Increased customer satisfaction *Value-added services *Intellectual property	*Improved service *Differentiated/lower tariffs *Facilitated competition/switching *Reduced read errors *Availability of consumption data *Reduced wait for contract changes

There are key aspects of Enel's meter technology and business case that differ significantly from our situation and prevent a direct application of the Enel AMI solution to our system. The main differences are:

- Meters: Enel designed the meters to meet its specific electrical system requirements, which for residential customers is 230 volt, 50 Hz service and to meet IEC standards. The meter was not designed to meet the ANSI C84.1 standards used in the United States and therefore, does not meet our electrical system requirements, which for residential service is 120 volt, 60 Hz service.

- Communication Concentrators: Enel's distribution system averages 88 customers per distribution transformer, enabling Enel to install communication modules at each distribution transformer, resulting in lower communications infrastructure costs. By contrast, due to electrical system requirements, U.S. utilities have a much lower customer per transformer ratio. As such, our distribution system averages five customers per transformer, and thus does not allow for similar, low levels of communications infrastructure costs.

- Meter Read Frequency: Prior to the implementation of AMI on its system, Enel's meter reading frequency was significantly less than once per month. This was a key functional/operational consideration for Enel. By comparison, we already read meters and bill customers monthly as required by the Commission. Thus, we already experience this operational efficiency and would not expect any incremental benefits from AMI on the issue of frequency of meter reading.

- Meter Access: A large percentage of residential meters in Italy are located inside the home, which is typically considered as difficult to access. Thus, Enel was able to realize significant operational benefits by achieving remote read capabilities. Meter accessibility is not as significant a challenge in the majority of our service territory. Additionally, we have already deployed AMR technology for some of the most inaccessible and unsafe to read meters so we already experience this operational efficiency.

- Unaccounted for Energy (UFE): Enel experienced a very high degree of UFE because of (1) unbilled energy consumption (low frequency of reading meters) and (2) energy theft. In fact, we understand that Enel estimated that a significant portion of its AMI deployment costs will be recovered by reduced UFE alone. We do not have a comparably high incidence of infrequent reading of meters or UFE because we have already implemented systems and practices to mitigate those problems. Accordingly, we expect to capture significantly fewer benefits in this category as compared to Enel's experience.

Although the Enel solution is not commercially applicable to our situation, the business approach to solving a similar technology challenge is a good model for SCE. We have learned that Enel's "clean sheet" approach to the design of a new integrated AMI meter provides significantly greater functionality and correspondingly greater customer benefits at a fraction of the total cost of the otherwise commercially available products.

2. Additional Functionality Not Offered in a Comprehensive Solution

We expect to develop a metering solution that provides functionality and benefits beyond the current marketplace offers to meet our operating needs. Table 2-1 below illustrates the features and functionality that could be incorporated in a new meter design.

Feature/Function	Currently Available	Enel Meters	SCE's Design
Remote Interval & On-Demand Reading	Yes	Yes	Yes
Maximum Power Consumption	Yes	Yes	Yes
Remote Curtailment – demand limiting	No	Yes	Yes
Remote Connect/Disconnect[1]	No	Yes	Yes
Energy Use Display – Text messaging & enhanced features	No	Yes	Yes
>35 Days On Board Memory	No	Yes	Yes
Continuous Service Monitoring	No	Yes	Yes
Pre-payment	No	Yes	Yes
Multiple Data Ports[2]	No	No	Yes
RF Link to In Home Devices	No	No	Yes
Wireless Link to Gas/Water Meters	No	No	Yes
Integrated Load Control[2]	No	No	Yes
Two-leg voltage Measurement[2]	No	No	Yes
Integrated GPS	No	No	Yes
Multi-RTU Protocol[2]	No	No	Yes
>15 Year Life Expectancy	No	No	Possible
Energy Display Trip Counter	No	No	Yes
Local Area Sensor	No	No	Yes

Table 2-1
Availability of Metering Functionality

[1]In some instances, this feature is available as an "add-on" component at additional cost.
[2]This feature is available in limited instances, generally for commercial and industrial meter applications.

The information in Table 2-1 illustrates that very few key features or functions are currently embedded in packaged AMI solutions. The Enel meter has many key functions including remote demand limiting that we believe add significant benefits to an AMI solution. There are also many additional features available in component form that potentially could be incorporated into a single, integrated meter solution. As explained in Section II.A, the metering industry is not likely to develop a comprehensive AMI solution on its own in the near future. Moreover, our thorough evaluation of available AMI technologies establishes that merging components into the meter after-the-fact is prohibitively expensive, with an individual feature module often costing as much or more than the meter itself. However, if key functionalities are integrated into the meter itself, the incremental cost decreases dramatically, thereby making inclusion of such additional features – and their derivative benefits – a reality that does not exist today. Through our deployment strategy, we anticipate significantly increasing AMI's functional capability for about the average cost of today's stand-alone meter solutions used in our business cases scenario analysis.

3. SCE Metering Development Experience

In 1986, we commissioned Metricom, Inc., to develop and produce hardware and software for a two-way network communications system known today as NetComm. Working with Metricom, we designed, developed specifications, tested, and installed about 30,000 interval meters on residential and commercial premises. This meter is capable of measuring various parameters (watts, kilowatts-hours, reactive power, current and voltage), as well as being able to profile individual meters on single-minute intervals. The solid-state meters can also record outages and are readable over powerline carrier (220 kHz) from Metricom radios installed on the distribution system. At that time, some metering functions that were investigated included major appliance and circuit load control with verification, time-differentiated measurement, and remote meter reading. Many of these Metricom meters are still in use today for load research purposes. This example of a development activity, where we successfully worked to develop a solid state meter with architecturally integrated PLC and RF communication platforms, demonstrates that we have the requisite experience to make our AIM deployment strategy a reality.

III.

PROPOSED DEPLOYMENT STRATEGY

A. Overview

This section provides a detailed discussion of our preferred deployment strategy. This strategy involves design, development, and deployment of a custom-designed AIM product that integrates expanded functionality (significantly greater than currently available AMI solutions) using a three-phase process. This section also describes our design objectives and actual meter development process, including the costs associated with each phase of development.

Additionally, this section describes the activities associated with our final business case development and those start-up activities of long duration. We also describe the product development organization, timeline, schedules, and related activities. Finally, this section describes the feasibility analysis assessing the validity of new meter development.

B. Approach

1. Design Objective

The key to successful economic implementation of this AMI strategy is quite basic: designing a meter that includes desired meter functionality and delivers enough reliable and quantifiable benefits to outweigh the costs of deployment. Currently, the costs of implementing AMI are too high for the benefits to offset them in a reasonable amount of time. As discussed in Section II, there are specific characteristics that an AMI meter solution must possess in order to improve our current business case. These specific characteristics are at the core of our design objective for the AIM and are discussed further in the sections that follow.

a) New Meters Should Provide Multiple Operational Benefits

As shown in our October 2004 and January 2005 preliminary business case analyses, material operational benefits for our system must include more than simply meter reading cost savings. As discussed in Section II, we have concluded that significant benefits can be derived if the right set of technologies is integrated into a meter designed on open standards. We are confident that we can form qualified design and manufacturing alliances to develop an integrated meter that delivers the desired functionality at a lower price than would be possible if we attempted to combine those components today with add-on modules.

In addition to supporting the Commission's six key AMI functional goals described in Section II, we envision our "clean sheet" custom-design approach to include meter functionality that:

- Supports interfaces with load control technology within and around the premise (*e.g.*, thermostats and device switches);
- Improves electric distribution management through power quality measurement at the customer premise;
- Improves customer services related to billing and payment (remote disconnect, tamper/theft detection, GPS);
- Enhances system load control though premise-level demand limiting;
- Supports multiple network communication schemes through open "plug and play" interface standards and communications protocols; and
- Supports open standards related to communications and messaging to premise devices and energy management systems (*e.g.*, ZigBee, Z-Wave and web services).

We fully expect that the AIM product based on this approach will provide a robust, flexible, and extendible platform for the 15-plus year lifecycle of this investment.

b) New Meters Should Support a Range of Price-Responsive and Load Control Systems

The AMI solution must support a range of price-responsive and load control capabilities to maximize demand response benefits from reduced customer demand at peak times. The load reduction opportunities available to residential customers are as diverse as their usage behavior. However, a customer's reluctance to be exposed to actual market price volatility, and the lack of a day-ahead transparent and functioning market at this time, limit the methods by which price signals can be provided to customers when a high, peak demand is expected. Additionally, AB1X hinders implementation of time-differentiated rates until the expiration of the CDWR contracts in 2013. For these reasons, load controlled by the utility is of high value today. Such control allows the utility to curtail load on short notice compared to the longer horizons required by day-ahead notice and difficult-to-predict actual customer response to time-differentiated prices.

Advanced meters, such as those deployed by the Italian utility, Enel, can also measure and control customer demand levels. As might be expected, with an appropriate meter design, residential customers could enroll in a demand-limited service that is priced based on peak demand. Moreover, if demand limiting and/or automated load control equipment were integrated into a new meter design, such functionality could increase overall demand response benefits from AMI by providing customers with a way to respond to time-differentiated rates during critical peak events. Such functionality would also allow utilities to deliver dispatchable load curtailment during system emergencies.

c) New Meters Should be Adaptable

The ability to incorporate current state-of-the-art technology into future meter innovations is a key design objective that has been embraced by several regulatory agencies. The California Energy Commission (CEC) held a Staff Workshop on

February 1, 2005 on the development of a reference design for demand response. The purpose of the reference design is to encourage "open architecture" and to develop potential new desired functionality for the demand response infrastructure. This activity aligns well with our design adaptability objective and underscores the need for "open standards." In support of the open standards effort, the meter industry has organized a group called "Open AMI" to develop such a reference design. We support this initiative as demonstrated by our utility advisory board membership and by our active encouragement of vendors to participate.

Additionally, the CEC is working to develop a reference design for smart thermostats. This effort presents an opportunity to identify standards for communications between meters and thermostats. Some of these challenges may be streamlined by further expanding participation in the workshops to include members of the ZigBee Alliance and Z-Wave proponents. We look forward to working with the CEC on the development of open standards that are consistent with our design objectives

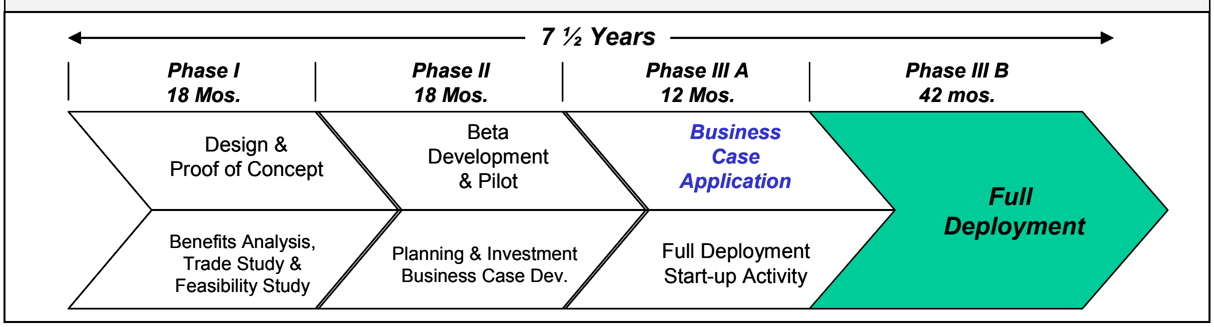
d) Achieving the Design Objectives

In order to achieve our design objectives, we propose to design and develop a new metering system that has an integrated package of features that quickly and feasibly incorporates functionalities that better support business operations and provide greater customer benefits at lower overall costs. The goal of our "clean sheet" approach is to close the existing business case gap between costs and benefits for AMI. As pointed out, Enel faced similar technological challenges and was able to successfully design and build a more functional meter at a fraction of the cost to commercially-available "off-the-shelf" products. Unlike Enel, we do not envision actually manufacturing the meter ourselves; rather, we intend to create a new design and prototype by working with an experienced engineering design firm, in collaboration with equipment and manufacturing firms. Once our design is completed, we anticipate that the AIM product will be manufactured by existing vendors.

2. Meter Development Method

For the AIM project, we intend to use a product development strategy based on the Stage-Gate® approach for the new product development. Stage-Gate® -based processes are widely viewed as sound methods for developing new products from idea to launch. Briefly, the Stage-Gate® process is divided into a series of activities (stages) and decision points (gates) whereby one does not proceed to the next stage until the prior stage is determined to be successful. We have adapted an aggressive AIM meter development process to this method as shown in Figure 2-3 below.

Figure 2-3
AIM Meter Product Development Process



Once we have identified the need for the AIM product, these stages are logically grouped into three distinct phases:

Phase I - Design and Proof of Concept;

Phase II - Beta Development and Pilot; and

Phase III - Commercialization and Full Deployment.

The objectives of Phase I of the project will be to define and develop the product from concept, through working prototype, to final design. Phase I will also include a confirmation of product manufacturability, unit pricing, and initial feasibility. We anticipate submitting a preliminary feasibility analysis report to the Commission at the end of Phase I that will be based on the results of Phase I activities. The report will also provide an update of our initial cost estimates based on information learned in Phase I.

Phase II's objectives will focus on confirming the product's commercial manufacturability through beta production and pilot field deployment. The Phase II pilot will also conduct limited testing of product functionality and integration with various utility systems. This phase is necessary to demonstrate operability and performance on a reasonable scale of up to 5,000 meters over approximately six-months. We believe this period will be sufficient to assess end-to-end integration with utility systems to validate the business case, a pivotal precursor to seeking full deployment. Our current application seeks Commission authorization and cost recovery for only Phases I and II.

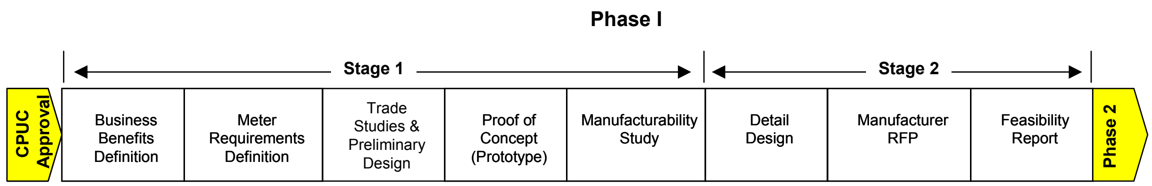
At the end of Phase II, we intend to file an application with the Commission seeking authority for full deployment AIM product if the final business case analysis demonstrates that it is beneficial for our customers to proceed with such deployment. This future application will incorporate the information and knowledge gained during Phases I and II and demonstrate whether the benefits and costs are sufficient to proceed with full deployment.

Phase III will involve the initiation and implementation of a full AMI meter deployment throughout our service territory upon regulatory approval. This includes all required start-up and system development activities, system integration requirements, implementation of operational and organizational changes, and mass meter production and deployment.

3. Phase I: Concept Development

Phase I encompasses the first two stages in the development process – Idea Development and Concept Development. Phase I includes development of functional requirements through proof of concept and preliminary manufacturability and financial feasibility analyses. The overall product development process and key activities for Stages 1 and 2 of Phase I are identified in Figure 2-4 below.

Figure 2-4
Phase I Summary Schedule



Stage 1 involves defining the product, preparing the preliminary design and building and testing working prototypes. The key activities during this stage are: a) defining the product, b) defining the requirements to meet the product definition, c) translating the requirements into an initial design, d) conducting a preliminary product feasibility analysis, e) confirming the concept will work functionally by building prototypes and testing them, and f) confirming that a prototype with the desired functionality can be manufactured relative to the target price.

Several design documents and manufacturability assessments are completed during this stage and include the following deliverables:

- Product Definition;
- Functional and Technical Requirements Document;
- Required Standards Document;
- Preliminary Design;
- Working Prototype and Test Report;
- Design Revision Based on Manufacturability; and
- Initial Product Financial Analysis Report.

Stage 2 focuses on developing the final product design, confirming product manufacturability through a competitive RFP for production, and development of preliminary financial analysis. Key activities during this stage are: a) developing the design to commercial production standard, b) confirming that the product can be built and meet the target price via existing manufacturers' capability, and c) confirming that the product is financially sustainable based on a preliminary feasibility assessment.

Several design documents and manufacturability assessments are conducted during this stage and include the following deliverables:

- Manufacturing Design Specification;
- Vendor RFP Results;
- Final Supply Chain Approach with the selected vendor(s); and
- Updated Benefit Analysis.

4. Phase II: Beta Development, Pilot Deployment and Business Case

Phase II involves the third and fourth stages of the development process, as well as the preparation of an "investment grade" business case for full deployment. Phase II objectives are to: a) confirm the product's commercial manufacturability through beta production, b) pilot field deployment and testing of product functionality, c) develop business case for full scale deployment of the new AMI solution across SCE's service territory for all customers with demands of less than 200 kW, and d) begin preliminary, detailed, business requirements definitions related to long-lead tasks required for full deployment.

a) Beta Meter Development and Field Testing

The beta meter development and field testing in Phase II are necessary to demonstrate the operability and performance of the AIM technology on a reasonable scale of up to 5,000 meters for each vendor selected over a six-month pilot period. The pilot will assess limited end-to-end integration with utility systems in order to validate the preliminary feasibility studies and facilitate a decision to proceed with full deployment.

Stage 3 is the beta meter development stage. This stage involves engaging one or more meter manufacturers to produce beta meters in sufficient volume to refine the final meter design and manufacturing processes. The key activities during

Stage 3 are: a) working with the selected manufacturers to refine design specifications, b) producing beta meters, and c) bench testing beta meters for field deployment.

Several design documents and manufacturability assessments are completed during this stage and include the following deliverables:

- Final design specifications;
- Field test performance results; and
- Final product feasibility analysis.

Stage 4 is the field testing stage. This stage involves deploying the beta meters and conducting a long-term field test. Key Stage 4 activities are: a) deploying beta meters, b) conducting field test, and c) completing final AIM product feasibility analysis. Several design documents and manufacturability assessments are conducted during this stage and include the following deliverables:

- Field test performance results; and
- Final product feasibility analysis.

b) Business Case and Preliminary Activity

During Phase II, we will further develop our full deployment business case analysis to reflect additional operational benefits derived from the new AIM product and to develop a more definitive cost estimate and full deployment schedule. Additionally, we will begin several start-up activities related to long-duration tasks. This should minimize the duration for a full deployment scenario. These activities will be done concurrently with the beta meter development in Phase II. The results of the business case analysis developed in Phase II will be filed with the Commission as part of an application seeking full deployment of the AIM product, contingent upon successful development and field-testing and upon a demonstration that it is beneficial for our customers to proceed with a full deployment of the AIM product.

Development of a robust business case requires that we define the scope of various operational activities and potential efficiencies and benefits beyond what was necessary for the current AMI technology due to the limited functionality. This would include defining scope and functionality for information systems, supply chain automation, and requirements for installation at a sufficient level to prepare detailed cost estimates and schedules. Because most of these operational activities span several functional areas within SCE, we will require facilitated joint application development (JAD) sessions. Such operational processes include:

- Distribution field work management;
- Meter installation workflow;
- Meter supply chain from vendors to field;
- Billing, collections and customer care;
- Meter data management;
- Energy forecasting and settlements;
- Safety; and
- Distribution grid operations and management.

Our experience over the past two years in the AMI proceeding suggests that a significant number of existing and incremental SCE personnel will be involved in the business case development effort. We will also require contract personnel and consultant support to assist in the facilitation and coordination of defining the scope of the necessary project work elements, assimilating cost estimates and preparing a program schedule.

We know that the development of several software applications related to meter workflow management, supply chain automation, and meter data management, along with meter installation field tool development, have relatively long durations. These tasks are part of those start-up activities that must be completed before meter installation can commence. Therefore, we anticipate beginning the preliminary business process design and system requirements activity associated with these tasks in Phase II.

Additional contract personnel/consulting support will be needed to redefine the business processes in the operational functions noted above, in the identification and analysis of process automation opportunities, and for assistance with defining detailed business requirements.

5. Product Development Organization

We intend to use a formal product-development team comprised of internal personnel and external contractors to assist with design and prototype development. We also recognize the value of collaboration with several key stakeholders, including the CEC, during the product development process.

a) Product-Development Team

We plan to utilize a mix of internal and external resources to staff the AIM product-development team. Our personnel will manage the overall product development process. Functional expertise will be provided by SCE personnel in several areas such as customer preferences, metering and testing, load control systems, Transmission and Distribution (T&D) operations, customer services and billing, communications, systems architecture, and utility software applications.

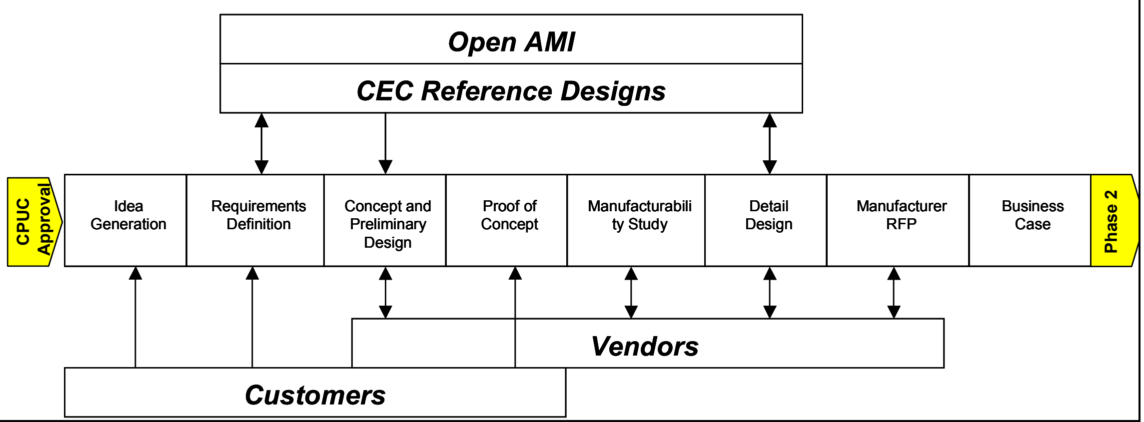
We intend to engage a consulting Chief Systems Engineer to represent our interest, from a technical perspective, in the product development effort by working with the selected engineering design firm, vendors and other stakeholders. Additionally, the Chief Systems Engineer will facilitate the process to define product requirements, guide design options, provide technical oversight and assist with the management of the product-development process through meter manufacturing vendor selection.

We intend to contract out the engineering design and prototype development activities to a vendor with proven, product-development experience in the engineering design of electronic products, embedded systems, and communications platforms. Such expertise will be required for the successful development of the new AIM product. The scope of the engagement will include the entire product-development process including concept development, architecture development, detailed manufacturability design, testing, and prototype development. We anticipate that the selected firm will provide a product-development team composed of a wide range of engineers experienced in product development. We anticipate this group to include metering engineers, mechanical engineers, electrical engineers, communications engineers, printed circuit board (PCB) designers, software engineers, industrial engineers, and test engineers.

b) Vendors and Stakeholders

We recognize the value that customers, vendors, and other key stakeholders can bring to this effort. Accordingly, we will continue to incorporate the findings of our customer market research in developing our design. We will also continue to participate and support the CEC's Open AMI effort because of the promise it holds for the establishment of open standards and a reference design, one of our key design objectives. Additionally, we will collaborate with the CEC and industry manufacturers on the reference design for smart thermostats and other areas of common interest. We will also invite meter, load control and ancillary product vendors to collaborate and influence the AIM meter design to ensure achievement of a product design that meets our cost and design goals. The conceptual model in Figure 2-5 below illustrates the collaboration with key stakeholders expected during Phase I.

Figure 2-5
Conceptual Stakeholder Collaboration Model



6. Budget for Phases I and II

To develop a budget forecast for Phases I and II, we gathered data through a modified RFI process with iterative steps for data gathering, clarification or refinement. This process began with an evaluation of existing full service engineering design firms and existing meter manufacturers that could potentially deliver the engineering design services that would be required in the development of the envisioned AIM meter.

Engineering design providers were asked to prepare a preliminary proposal adequate to meet the requirements of the new product-development process. We also asked them to submit proposals for the role of the Chief Systems Engineer. The proposals were to be reasonably consistent with available technologies, and executable under the specified parameters. Proposals were also to include a price estimate, methodology, and schedule for Phases I and II. Further, we requested preliminary proposals from business consulting firms for the Chief Systems Engineer role and support for the development of the business case, business process and requirements, development and overall program management, as required in Phases I and II. For the sake of time, the financial data provided by the engineering design providers and business consultants were normalized through a series of verbal communications with each of the service providers. We also requested preliminary cost estimates and schedules for beta production from meter manufacturers to prepare budget estimates. The beta production costs will be determined through a competitive bid process during Phase I.

Based on these data and communications, our budget estimate for Phase I totals $12 million over an 18 month period. This estimate includes the cost of engaging a consulting Chief Systems Engineer, preparation of a feasibility study, contracting engineering design, creation of detailed manufacturing design specifications, and the development and testing of working prototypes.

The budget estimate for Phase II totals $19 million over 18 months. This estimate includes the cost for engaging a consulting Chief Systems Engineer, retaining the engineering design firm for transition to manufacturing and contracting with meter manufacturers for the development and testing of up to 5,000 beta production meters for field test. This estimate also includes development of the final business case and initial start-up activities as described above.

Table 2-2 below details the budget estimates for the key activities in Phases I and II. We have prepared cost estimate breakdowns by year and by phase for anticipated expenditures in the major categories of business consultants, design firm, Chief Systems Engineer firm, beta testing, and SCE incremental activities. However, in order to avoid an adverse impact on our planned Request for Proposals for several of these activities, we have not provided this more detailed cost information here.

Table 2-2
Budget Estimate for Phases I and II Activities

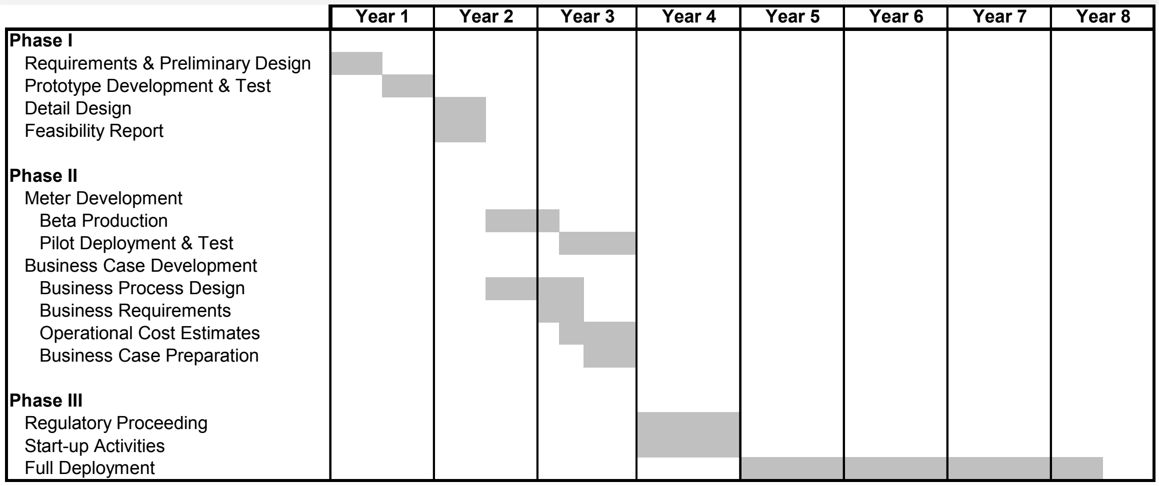
	Year 1	Year 2	Year 3	Total
Phase I Estimated Costs	**$8.0**	**$4.0**	**$0.0**	**$12.0**
Phase II Estimated Costs	**$0.0**	**$10.5**	**$8.5**	**$19.0**
Total Estimated Costs	***$8.0***	***$14.5***	***$8.5***	***$31.0***

Budget estimates for Phase III (full commercialization and system deployment) will be prepared as part of the business case developed towards the end of Phase II.

7. Timeline

Based on vendor responses and our own internal estimates, we anticipate Phase I to require 18 months, followed by Phase II that will also require 18 months, as defined in Figure 2-6, below. If the development process is successful, we will have up to 5,000 proven AIM meters within 36 months after development begins. After Phase II, we anticipate the need to begin significant pre-deployment activity so that we can be ready to begin full meter installation after final Commission approval of our business case application, as identified in Phase III in the figure below. Once Commission approval is obtained, meter installation will commence. Full deployment installation may take up to another 42 months, resulting in an overall duration of as little as seven-and-a-half years from concept to fully operational AMI system. Assuming the Commission approves our Phase I and II application on our proposed timeline for a final decision in September 2005, we anticipate completing full deployment in 2011 or 2012, provided there are not significant unforeseen problems or delays. This schedule is aggressive, but realistic based on our analysis and experience. Moreover, due to the time available for extensive start-up planning and advanced systems integration, we expect that actual meter installation for the AIM product will take less than the five years we have estimated for today's AMI metering solution, thereby only slightly increasing the overall project timing requirements above a deployment today.

Figure 2-6
AIM Meter Product Development and Process Timeline



C. Feasibility

We have considered several factors in assessing the viability of developing a new meter. These factors are shown in Table 2-3 below.

Table 2-3
Factors Considered for the Meter Development Feasibility

Item No.	Factor	Determination
1	Existence of basic technology for desired functionality	Several commercial components exist for each identified functionality
2	Successful commercial meter development by a utility at a lower price	Enel has developed meters with similar functionality and is deploying up to 30 million meters at a price under USD $80 per meter
3	Previous successful experience in joint product development with similar technologies	SCE successfully developed the Netcom network and an advanced solid state meter product which is still used today for load research purposes
4	Vendor interest in meter development	Very strong interest expressed by several meter technology vendors
5	Existence of Open Standards and reference design for a new meter	Open standards have been developed by ANSI but not yet adopted and under development through Open AMI and CEC efforts
6	Sufficiency of SCE's five million meter requirements to reach manufacturing economies of scale resulting in a reasonable price	A leading meter manufacturer confirms that SCE's meter requirement can achieve required economies of scale

With regard to open standards, several wireless communications standards and web-based messaging protocols exist that can be leveraged, key ANSI metering standards exist, and several interoperable standards can be applied to a new meter design. However, there is not yet concurrence on many of these standards as they may be applied to meter design and this is the focus of the Open Standards and AMI effort and the CEC's AMI reference design. We expect that our design effort will provide the catalyst to obtain concurrence on the Open AMI reference design.

IV.

COST RECOVERY PROPOSAL

This section sets forth our cost recovery proposal for the costs that we expect to incur during Phases I and II of our deployment plan. Specifically, we are requesting Commission approval for the recovery of all costs associated with the Phase I and Phase II activities in our AIM deployment proposal as described in Section III of this volume. We currently estimate approximately $12 million for Phase I activities, which will encompass AIM idea creation and concept development over an 18-month period. For Phase II activities, which include AIM beta development and pilot deployment, we currently estimate that we will spend approximately $19 million over another 18-month period. At this time, we are not proposing any ratemaking or cost recovery associated with Phase III activities, which include AIM start-up activity and full deployment, as those costs will be part of our future application in Phase III.

Currently, we anticipate that we will submit a preliminary feasibility analysis report to the Commission at the end of Phase I. This report will also provide a breakdown of actual Phase I costs incurred-to-date and updated cost estimates for Phase II activities. If, towards the end of Phase II, it is determined that we will proceed with full AIM deployment, a business case application will then be filed with the Commission including cost estimates and proposed ratemaking treatment for the full deployment effort.

A. Establishment of the Advanced Integrated Meter Balancing Account (AIMBA)

To provide for the recovery of Phase I and Phase II costs, we propose to establish the Advanced Integrated Meter Balancing Account (AIMBA) effective upon a Commission decision approving this application.[7] Similar to other Commission-authorized balancing accounts, the AIMBA will ensure that our customers will only pay for the recorded operations and maintenance (O&M) and capital-related revenue requirements ultimately found reasonable by the Commission associated with Phase I and Phase II activities as described in this exhibit.[8]

B. Proposed Operation of the AIMBA

In terms of the operation of the AIMBA, each month, we will record the difference between the actual capital-related revenue requirement and the actual O&M costs incurred by SCE for AIM Phase I and Phase II activities and the Commission-authorized AIM-related revenues in the AIMBA. The balance in the AIMBA will earn interest at the three-month commercial paper rate. The proposed operation of the AIMBA will ensure that no more and no less than our reasonable AIM-related revenues are ultimately collected from customers. Similar to ratemaking principles applicable to other Commission-approved balancing accounts, this would be accomplished through an annual "true-up" process, in which year-end under- or over-collections in the AIMBA will be added to the next year's forecast of the AIM-related revenue requirement.

The AIM-related revenue requirements will be collected in rates as one component of our total distribution rate levels. Regardless of the effective date of

[7] SCE's current Advanced Metering and Demand Response Memorandum Account (AMDRMA) includes, among other items, the incremental, one-time setup and ongoing Operation and Maintenance (O&M) and Administrative and General (A&G) expenses incurred for Phase 2 activities as authorized by the November 24, 2003 "Assigned Commissioner's Ruling and Scoping Memo (Phase 2)." The primary purpose of those Phase 2 activities was to develop a methodology for conduct of a business case to determine the cost effectiveness of wide-scale deployment of AMI, which SCE provided in its October 2004 and January 2005 submittals in R.02-06-001. Costs associated with SCE's "clean sheet" approach to develop the design for the AIM meter (Phase I and Phase II activities) are not authorized for inclusion in the AMDRMA.

[8] The capital related revenue requirement is defined as the sum of: (1) depreciation, (2) *ad valorem* taxes, (3) taxes based on income, and (4) the applicable rate of return on ratebase.

the Commission's decision on this application, we propose to begin the actual rate recovery of our AIM-related revenue requirement on January 1, 2006, when all other authorized rate changes are consolidated.[9] We will provide our January 1 AIM-related revenue requirement to the Commission for approval at least 60 days in advance by Advice Letter.[10] We propose to consolidate the changes to SCE distribution rate levels to reflect the updated annual AIM-related revenue requirements in conjunction with other rate level changes in our annual Energy Resources Recovery Account (ERRA) applications.

Pursuant to Commission-adopted revenue procedures for other SCE balancing accounts, we propose that the recorded operation of the AIMBA be reviewed by the Commission in SCE's annual ERRA reasonableness applications to ensure that all entries to the account are stated correctly and are consistent with Commission decisions. Due to the uncertainties surrounding a successful outcome of our AIM development process as we proceed through the Phase I and Phase II tasks, or the possibility that a future Commission may change its views about deployment of AIM, Commission reasonableness review of the AIMBA should be limited to ensuring that all recorded costs are associated with Phase I and Phase II activities as defined and adopted by the Commission in this proceeding.

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[9] Therefore, because we are not proposing any AIM-related rate changes for 2005, there will not be any AIM-related revenues recorded in the AIMBA in 2005. Any under-collection in the AIMBA at the end of 2005, will be included in the forecast of the January 1, 2006 AIM-related revenue requirement.

[10] Each year's forecast of the AIM-related revenue requirement will include the most recent forecast of that year's Phase I or Phase II AIM-related O&M and/or capital expenditures. The forecast revenue requirements will reflect the most recently adopted rate of return on rate base, franchise fees and uncollectible accounts expense rate, and income tax rates as applicable.

Application No.: A.05-03-

Exhibit No.: SCE-3

Witnesses: D. Berndt
P. De Martini
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SOUTHERN CALIFORNIA
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(U 338-E)

Testimony Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism

Volume 3 –Advanced Metering Infrastructure Business Case Analysis

Before the

Public Utilities Commission of the State of California

Rosemead, California

March 30, 2005

Advanced Metering Infrastructure Business Case Analysis

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I.

INTRODUCTION

The purpose of this volume is to describe our "best" full and partial Advanced Metering Infrastructure (AMI) deployment scenarios, as required by the Assigned Commissioner and Administrative Law Judge's Ruling issued on November 24, 2004. Although SCE does not recommend either of these scenarios, we describe them here based on the criteria and assumptions contained in Attachment A of the July 21, 2004 Ruling. The July 21, 2004 Ruling identified eight full deployment scenarios and eight partial deployment scenarios for the utilities to analyze. After conducting analysis of these scenarios, SCE found that Scenarios 7 and 21 were the "least-unfavorable" full and partial deployment scenarios, respectively. However, because both of these scenarios included the benefits of a proposed Advanced Load Control (ALC) program that could be implemented without AMI, SCE does not consider them true AMI cases. Therefore, from a purely AMI business case perspective, our "least-unfavorable" AMI business cases are Scenarios 4 and 17.[1] Both Scenarios 4 and 17 include operational and demand response benefits which are based on the assumption that all new AMI-metered customers would be offered the CPP-F or CPP-V rate on a default basis (*i.e.*, with an "opt-out" provision).

Section II of this volume summarizes the results of our "best case" full and partial deployment scenarios.

Section III provides an overview of the operational impacts expected from full and partial deployment.

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[1] As presented in this Application, Scenario 17's results show a less-negative net present value (NPV) than when that scenario was presented in our January 2005 compliance filing. This change reflects modification of the deployment strategy to include AMI meter installations only in the high density portions of Zone 4 in order to achieve a higher AMI communication success rate.

Sections IV and V provide detailed cost and benefit analyses for the "best case" full and partial deployment scenarios, respectively. The cost analyses are presented in terms of the July 21, 2004 Ruling's five applicable cost categories[2] and 79 individual cost codes associated with these cost categories. The benefit analyses are presented in terms of the four major benefit categories and the individual benefit codes that were actually used in this analysis.[3] These two sections also include discussion of the risks and uncertainties identified to date and present an NPV analysis, based on the costs and benefits identified, for the two "best case" scenarios. Lastly, these sections set forth the preliminary revenue requirement and impact on customer rates of the "best case" full and partial deployment scenarios.

[2] The July 21, 2004 Ruling specifies a sixth category for natural gas impacts. These costs are not applicable to SCE's business case analysis and thus, are not included.

[3] A summary discussion of all 40 benefit codes, whether used or not, is contained in Appendix H of Volume 4.

II.

SUMMARY OF RESULTS

As directed by the November 24, 2004 Ruling, the following sections describe our "best case" full deployment scenario and "best case" partial deployment scenario. In reviewing the business case analysis, we determined that the "best case" full and partial deployment scenarios involved a default CPP rate. These were presented as Scenarios 4 and 17 in our January 2005 compliance filing.

A summary of the revised costs and benefits on both a pre-tax cash flow and a revenue requirement NPV basis for each of the two "best case" scenarios is presented below in Table 3-1 below.

Table 3-1

Summary of Best Case Full and Partial AMI Deployment
(Costs and Benefits in Thousands of 2004 Present Value Dollars)

Scenario Description	Number of AMI Meters	Total Cost	Total Benefits	Pre-Tax Subtotal	After-Tax NPV	Rev. Req. NPV
Full Deployment (Scenario 4)	4.5 million	($1,298,413)	$804,648	($493,765)	($402,860)	($951,815)
Partial Deployment (Scenario 17)	325,000	($164,158)	$77,691	($86,467)	($60,880)	($129,901)

The July 21, 2004 Ruling's required analysis parameters included the assessment of uncertainty and risk in both a quantitative and qualitative manner.[4] The above summary includes the results of our Monte Carlo simulations of the cost parameters and the demand response benefit elements of both "best case" scenarios, which resulted in cost contingencies for the full and partial scenarios of $64.5 million and $7.5 million in 2004

[4] July 21, 2004 Ruling, pp. 12-13.

present value dollars, respectively. We believe a 90 percent confidence level is reasonable for this type of project and these amounts represent achieving this confidence level. A qualitative description of these risk parameters is included at the end of the business case for each scenario.

A. Summary of Costs and Benefits

Table 3-2 summarizes the total estimated costs and benefits we expect will result from deployment of AMI under Scenarios 4 and 17.

Table 3-2
Summary of Costs and Benefits
(2004 Pre-tax Present Value Dollars in Millions)

Line No.	Cost Benefit Category	Scenario 4	Scenario 17
1	Meter System & Inst. Costs	$668,399	$60,063
2	Communication System Costs	41,974	6,478
3	Information Technology Costs	206,003	45,475
4	Customer Services Costs	211,459	23,122
5	Management and Other Costs	170,578	29,021
6	**Cost Total**	**$1,298,413**	**$164,158**
7	Systems Operations Benefits	$307,333	$20,655
8	Customer Service Benefits	8,268	3,860
9	Management and Other Benefits	122,316	10,309
10	Demand Response Benefits	366,731	42,867
11	**Benefit Total**	**$804,648**	**$77,691**
12	**Pre-Tax Sub-Total**	**($493,765)**	**($86,467)**

Both of these scenarios assume that 80 percent of eligible customers are defaulted to CPP-F rates (residential) or CPP-V rates (commercial <200 kW)[5] and that those

[5] Customers with demands in excess of 200 kW are assumed to already have AMI type meters installed. Costs and benefits associated with implementing RTP rates are considered to be independent of this analysis (*see* the "Business as Usual" case in Appendix G of this filing, and Scenarios 12 and 13 in SCE's January compliance filing in this proceeding). The July 21, 2004 Ruling's required scenarios included moving customers over 200 kW to an RTP tariff. Rather than include large customers in Scenarios 4 and 17, we prepared separate business cases (Scenarios 12 and 13) to show the cost/benefit of this measure separately. These cases are summarized in Appendix I.

customers stay on those rates for the full duration of the business case. For analysis purposes, we assumed that the customers opting-out of the default rate would either switch back to their tiered rate or choose a time-of-use (TOU) rate in equal proportions. We have not adjusted the above demand response benefits for Value of Service Loss to customers due to participation in time-differentiated rates (TDRs).[6] For Scenarios 4 and 17, the Value of Service Loss is approximately $113 million and $6.2 million respectively (2004 present value dollars), reducing the total demand response benefit for each scenario by a similar amount.

B. Summary of NPV Analysis

Costs and benefits for each business case scenario were estimated by the appropriate operating organizations using current (2004) dollars for all non-labor costs, and job titles and estimated full time equivalent (FTE) employees for all SCE labor costs. All costs and benefits were estimated in 2004-dollars, escalated to the forecast year (2006-2021), and then discounted to 2004 present value[7] using SCE's long-term Weighted Average Cost of Capital (10.5 percent). Cost categories from the July 21, 2004 Ruling[8] were used to summarize planned expenditures, in nominal dollars, by category and year. Capital/expense, depreciation, and amortization analyses were performed for revenue requirements analysis without respect to the July 21, 2004 Ruling's cost categories. As shown in Table 3-1 above, Scenario 4 and 17 result in negative Revenue Requirement Present Values of approximately $952 million and $130 million, respectively. Accordingly, neither scenario supports the cost-effective implementation of AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the business

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[6] Our methodology and analysis of Value of Service Loss, by scenario, is presented in Appendix J.

[7] July 21, 2004 Ruling, p. 12.

[8] July 21, 2004 Ruling, Appendix A.

case analysis for each scenario, plus the recovery of SCE's net investment in any removed meters, and includes the rate of return and tax impacts of the AMI-related investments.

III.

OVERVIEW OF BEST CASE FULL AND PARTIAL DEPLOYMENT SCENARIOS

This section describes the effects of our "best case" full and partial deployment cases (Scenarios 4 and 17) on all of SCE's operations, processes and information technology systems. These two cases utilize all the assumptions set out in the July 21, 2004 Ruling and the functional capabilities of commercially available advanced meters and their supporting network using the radio frequency (RF) technology solution described in Appendix B. This section also contains a schedule of deployment for both scenarios, and describes how we will achieve the customer coverage required by the July 21, 2004 Ruling.[9] The two "best case" scenarios are described according to their impact on our operations, using the July 21, 2004 Ruling's five applicable cost categories. The costs and benefits of Scenario 4 and 17 are quantified in Section IV and V respectively, using the cost and benefit codes identified in Appendix A of the July 21 Ruling.

To achieve the 90 percent saturation goal set by the July 21, 2004 Ruling, full AMI deployment under Scenario 4 assumes that 4.5 million AMI meters will be installed in 97 percent of existing customer's homes and businesses, throughout our 34 service center and

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[9] Because the July 21, 2004 Ruling specified a "2006 to 2021 analysis period" (Attachment A, p.12) and directed that costs and benefits be "presented as 2004 present value dollars," (*Id.*), and to maximize consistency with its prior filings in this proceeding, SCE has continued to model its AMI deployment scenarios with consistent assumptions regarding the timing of the deployments. In this application, Scenario 4 (full-deployment) and Scenario 17 (partial-deployment) continue to show deployment beginning in the first quarter of 2006, with costs summarized in 2004 present value dollars. In reality, it is not possible to deploy AMI meters in any significant quantities during 2006, due to the remaining regulatory steps (hearings, briefs, proposed and final decisions) required before any deployment can be authorized, as well as the subsequent time required to solicit and evaluate vendor proposals, and for the successful vendor to gear up production. Any reference to a 2006 deployment of meters, throughout this Application, is solely a modeling assumption, and does not mean that SCE believes deployment in 2006 is feasible.

The basic economics of the deployment scenarios would be little changed by a revised 2007 or 2008 deployment assumption; the cost and benefit estimates could be adjusted for inflation, but one or two year's escalation assumptions will not change the overall determination that AMI deployment as specified in the July 21, 2004 Ruling, when applied to SCE's specific service territory and existing operations, is not cost-effective for SCE's ratepayers at this time.

rural office locations. Our partial deployment approach under Scenario 17 is based on the assumption that AMI deployment is best suited for the portion of our service territory where we can reasonably expect to realize the greatest load reduction and demand response benefits. The portion of our service territory meeting these two criteria is located in the more highly populated areas within Climate Zone 4, as delineated in the Statewide Pricing Pilot (SPP).[10] Scenario 17 assumes that 325,000 AMI meters will be installed.

Full scale AMI deployment will require a significant planning and start-up phase prior to the start of meter installation. Key start-up activities include business process redesign, significant personnel management, and development of communications and technology infrastructure. Business process redesign will be required for meter workflow management, customer services and billing operations, and meter procurement. Both the full and partial deployment scenarios require new hires, temporary employees, and a large contingent of consultants and the facilities to support them. The procurement process for full deployment is significant with over $600 million worth of meters, technology, and contract services required. This process will require significant time to manage selection and contracting, as well as to establish the meter inventory logistics. Our preferred deployment approach requires network installation and workflow management systems to be operational before meter installations begin, in order to ensure connectivity at time of installation and thus minimize costs.

This level of start-up activity may take 18 to 24 months to complete for partial and full deployment, respectively. We have not adjusted the timeline or business case to reflect this reality, but a more realistic start-up period will be reflected in any future application for full deployment.

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[10] The Charles River Associates analysis of SPP results confirmed that the highest percentage reduction of peak-period energy use for critical peak pricing customers occurred in Climate Zone 4 of the SPP. "Statewide Pricing Pilot Summer 2003 Impact Analysis," August 9, 2004, Charles River Associates, p. 83.

A. Metering System Installation and Maintenance

This section describes the operations, processes and systems affected by AMI deployment for activities that fall under the Ruling's Meter System Installation and Maintenance cost category. This cost category involves our meter procurement, supply chain management, testing, installation, and associated support activities. In order to better explain the effect of AMI deployment on these activities, this section also describes the number of customers who would receive AMI meters in the full and partial deployment business cases and our process for determining how we arrived at those numbers.

1. Number of Customers Receiving AMI Meters

a) Full Deployment (Scenario 4)

The July 21, 2004 Ruling requires that full AMI deployment reach no less than 90 percent of SCE's customers.[11] For SCE, this means that approximately 4.2 million meters must be deployed and operational. In order to properly determine the specific coverage capabilities of the communications technology infrastructure (see Appendix B), a comprehensive study would be required to identify the specific locations that can be cost effectively supported. For example, the RF path between a specific meter and the data collector can be obstructed by hills or large structures, thus creating a RF "blind-spot" even when the meter is located within the effective range of the network. Without an actual field survey of specific locations, it is not possible to determine which or how many meters will be affected. In lieu of such a study, we are providing an estimate of the deployment needed to meet the Commission's stated full deployment objective. We estimate that we will need to deploy AMI meters to 97 percent of our 4.7 million existing meters (*i.e.*, 4.54 million meters will be deployed) so that 90 percent (or 4.2 million) of our total meters will communicate with the network, as required. We estimate that the other

[11] July 21, 2004 Ruling, Attachment A, p. 6.

three percent of our meter population will not be included in full AMI deployment because it will not be economically feasible to do so (primarily due to remote locations) or because the meters are not owned by SCE (*e.g.*, direct access (DA) customer-owned meters). For the 97 percent of the meters that are deployed, we assume that once RF networks are operational, approximately seven percent of the deployed meters will fall within RF "blind spots" and thus will not possess remote read capability due to the unique positioning of the meter itself and/or its physical surroundings. This seven percent estimate is based on SCE's experience with existing RF infrastructure and a review of the meters that will likely fall outside of the planned coverage area because of the unique geographical terrain and customer population densities.

b) Partial Deployment (Scenario 17)

It is imperative that partial deployment be large enough to gain some economies of scale, but small enough to easily manage deployment risks. We believe the more populated areas of our Climate Zone 4, with about 325,000 customers, meets these criteria. In our earlier filings in this proceeding, our partial deployment Zone 4 Scenario assumed we would attempt to include the entire meter population, or approximately 450,000 customers. However, because this geographic region includes many sparsely-populated rural areas with varying topographical characteristics, we could assume only a 70 percent success rate in being able to communicate with the installed AMI meters. In the revised analysis of this partial deployment scenario, we targeted the most densely populated portions of Zone 4, which include Victorville and surrounding communities, the Lancaster/Palmdale area, and the resort communities of the Coachella Valley, including Palm Springs. This revision eliminated many of the less densely-populated areas and allows us to assume a more economic deployment. The revision enabled a higher assumed-connectivity rate for the AMI communications infrastructure, increasing from 70 percent to 94 percent. The reduction in meter count resulted in revisions to some of our meter systems installation assumptions, which will be discussed later in this volume.

2. Roll-Out Plans

In order to fully deploy 4.54 million AMI meters in a five-year period under Scenario 4, we will be required to pursue an extraordinarily aggressive deployment schedule throughout our service territory. Our service territory is comprised of 24 service centers serving the densely-populated metropolitan areas and 10 service centers serving the expansive, yet sparsely-populated rural areas. Approximately 98 percent of the 4.54 million meters to be deployed would be in service centers serving metropolitan areas. Accordingly, we have assumed the staging of the startup to the 24 service centers of Scenario 4. The startup to the three service centers of Scenario 17 would occur as shown in Table 3-3.[12]

[12] As discussed in Section I above, SCE's analysis continues to assume a January 2006 deployment. Given the likely regulatory schedule leading to any Commission order to deploy, actual meter deployment is not expected to occur until January 2007 or later.

Table 3-3
Full and Partial Deployment Start Date by Service Center
(Scenarios 4 and 17)

Line No.	Service Center	2nd Quarter - 2006	3rd Quarter - 2006	4th Quarter – 2006
1	Covina	4		
2	Long Beach	4		
3	San Jacinto Valley	4		
4	Compton	4		
5	Ventura	4		
6	San Joaquin	4		
7	Foothill		4	
8	Fullerton		4	
9	Santa Ana		4	
10	Huntington Beach		4	
11	Ontario		4	
12	South Bay		4	
13	Thousand Oaks		4	
14	Antelope Valley	17	4	
15	Saddleback			4
16	Redlands			4
17	Palm Springs	17		4
18	Montebello			4
19	Monrovia			4
20	Santa Monica			4
21	Santa Barbara			4
22	Valencia			4
23	Victorville	17		4
24	Whittier			4

As shown above, both full and partial deployment installations are assumed to begin in the second quarter of 2006. Full deployment would start in the six largest service centers (*i.e.*, those largest in terms of number of meters eligible for deployment). Deployment efforts would be expanded to eight additional service centers in the third quarter of 2006. Deployment efforts would be expanded to the remaining 10 service centers in the fourth quarter of 2006. For the 10 service centers that serve the rural areas of our service territory, full deployment is expected to begin in the second quarter of 2006.

We expect to complete full deployment under Scenario 4 in all of the 24 service center areas by the second quarter of 2010. Partial deployment in all three service centers under Scenario 17 would be started in the second quarter of 2006. Meter installations are expected to be completed in 18 months and the communications systems are expected to be operational at about the same time meter installations are completed. Partial deployment under Scenario 17 would not involve any of our rural service centers.

This deployment strategy considered meter densities, as well as concentrations of already deployed AMR meters. We have already deployed over one-half million AMR meters throughout our service territory, concentrating in those areas where it was most cost-effective. The majority of these AMR meters are read through a van-based process contracted out to a third-party provider. To meet the metering requirements set forth in the July 21, 2004, Ruling we expect to replace these AMR meters with AMI meters and prematurely terminate the meter reading contract. In order to mitigate the effect of AMI deployment on the investment in AMR, we considered the concentration of AMR meters associated with each service center. We would begin replacing the AMR meters as late in the deployment phase as possible in order to mitigate costs associated with stranding the AMR investment.

3. Annual Deployment Volumes

Table 3-4 shows the annual volumes of AMI meters to be installed under the full and partial deployment scenarios.

Table 3-4 AMI Deployment Number of Meters and Year of Deployment			
Line No.	**Year**	**Full Deployment (Scenario 4)**	**Partial Deployment (Scenario 17)**
1	2006	562,230	324,603
2	2007	1,129,665	-
3	2008	1,132,763	-
4	2009	1,135,861	-
5	2010	579,652	-
6	Total	4,540,171	324,603

The numbers in the above table only reflect initial installations and do not include replacements for meter failures or meters to accommodate approximately two percent annual customer growth. These subjects will be discussed in later sections.

4. Description of Meter System Installation and Maintenance Activities

The meter system installation and maintenance cost category includes all of our activities associated with meter procurement, supply chain management, testing, installation, and other required support. The effect of full and partial AMI deployment on these activities is described in detail below.

a) Meter Procurement

Based upon the various types of meter sites in our service territory, we expect to procure four different types of meters for AMI deployment. In addition to procuring the AMI meters, we will modify some of our inventory activities to accommodate full deployment. In the full deployment scenario, each newly procured meter will be equipped with a Radio Frequency Identification (RFID) tag. This allows us to automate the procurement and supply chain processes from initial receipt of the meter from the vendor all the way through dissemination of the meters to field personnel for installation. Under the partial deployment scenario, we will not need to make many changes to our inventory activities and we will not need to convert to the RFID systems to successfully accomplish the smaller scale roll-out.

b) Supply Chain Management

Currently, SCE's Procurement and Material Management (PAMM) group receives, stocks, and distributes approximately 120,000 meters per year. Under full deployment, the PAMM organization will increase its meter distribution to a peak of approximately 1.3 million meters a year, whereas, under partial deployment, meter distribution will increase by approximately 325,000 meters. In addition, under full deployment it is estimated that there will be approximately 1.5 million additional meters that will need to be distributed over the duration of the project, due to meter replacements that result from failures in the field. Meter failures may be attributed to hardware/component failures or technology related radio-frequency interference impeding meter data communications.[13] Under partial deployment, meter replacements due to failures are expected to total approximately 144,000. The estimated number of meter failures, by year under full and partial deployment, is shown in Table 3-5 below.

[13] AMI Technology failures are discussed in Appendix C.

Table 3-5 Estimated Meter Failures by Year			
Line No.	Year	Full Deployment	Partial Deployment
1	2006	21,379	10,988
2	2007	167,893	31,925
3	2008	142,724	16,178
4	2009	120,071	9,646
5	2010	92,025	6,399
6	2011	91,863	6,375
7	2012	91,671	6,349
8	2013	91,451	6,323
9	2014	91,200	6,292
10	2015	90,926	6,262
11	2016	90,628	6,231
12	2017	90,305	6,199
13	2018	89,960	6,165
14	2019	89,594	6,131
15	2020	89,206	6,095
16	2021	88,799	6,058
17	Total	1,539,692	143,616

Given our prior experience with meter vendor reliability, we propose to maintain approximately three months worth of inventory in our distribution facility. In order to meet the full deployment schedule described in Table 3-3, the distribution facility will need to begin stocking meters three months prior to distribution. This will allow PAMM to distribute 100,000 meters per month to various SCE locations beginning in January 2006 to support deployment and installation beginning in April 2006.

PAMM will deliver meters to the service centers one to two times a week so that materials are received on a just-in-time basis. This strategy will reduce the need for additional, secure storage structures at multiple facilities. Additional personnel will be required at service centers to process the meters when they are received. The meters will then be stored in a secure area until they are scheduled for distribution to installation personnel. Due to the short-term nature of the deployment effort, we propose to use a Temporary Project Accountant position to process meters at the service centers.[14] Such Temporary Project Accountants will also be responsible for distributing meters to installers on an installation schedule that will be developed. Once the installers replace existing meters with new AMI meters, the returned meters will be processed at the various service centers for salvage purposes.

c) Meter Testing

Under both full and partial deployment scenarios, we plan to test 100 percent of the first two meter shipments of residential meters for quality assurance purposes. After that point, we will use a statistically significant sampling method to test the meters. For commercial meters, we plan to test 100 percent of the first 10,000 commercial meters for quality assurance purposes. After that, we plan to use a statistically significant sampling method, similar to the residential meter testing, for testing the remaining meters.

Meter testing will be conducted at our existing meter shop facility. This facility will need to be reconfigured to handle the increased volume of work. Although AMI deployment will reduce some existing meter testing work, the meter testing workload will increase overall due to the scale and pace of AMI deployment. As such, additional personnel will be required to handle the increased testing activities.

d) Meter Installation

(1) Residential and Small Commercial (Less Than 20 kW)

In both full and partial deployment, we intend to utilize existing field services and meter reading personnel to install the AMI meters. Since the communications network and information technology applications related to AMI will not be operational until the third-quarter of 2007, for the first year and one-half of the

[14] Use of this temporary position assumes that we will be able to secure IBEW approval for such a position.

installation phase we will have to hire additional personnel to complete these installations while continuing our current level of meter reading and field service activities. Because this overlap period is short term in nature, we plan to use existing Meter Readers and Field Service Representatives to perform the installations and backfill the meter reading positions. As AMI becomes operational, we will eliminate the excess personnel through normal attrition. We expect this will allow us to avoid incurring any severance costs for full-time resources as AMI deployment concludes. The use of these temporary resources depends on the assumption that we will receive IBEW concurrence to reactivate the "Project Temporary Meter Reader" job classification and approve the creation of "Project Temporary Installer" and "Project Temporary Apprentice" job classifications.[15] We also expect to make use of mandatory overtime during the most pressing stages of deployment. Given the cost and performance trade-offs of utilizing overtime as an alternative to hiring incremental personnel, we expect to utilize both of these options.

(2) Complex Meter Installations

In our service territory, we have approximately 275,000 meters that are considered complex and therefore must be installed by Meter Technicians operating out of our Meter Services Organization (MSO). The partial deployment scenario includes approximately 18,000 complex meters. These complex meters are typically associated with Rate Schedule GS-2 and accounts with monthly demands above 20 kW. These also include all 430 volt accounts, network meters, and current transformers type metering. In order to support the aggressive full deployment schedule, we will rely on both full-time and contract resources, as well as the use of mandatory overtime, to install these complex meter configurations.

[15] IBEW approved the use of the project temporary meter reader job classification for the AMR deployment which took place in 2000. If represented employee labor were required, the cost estimates for meter installation could change.

e) Support Related Training Costs

In order to support AMI deployment, our field personnel will need to attend various training classes. As new Meter Readers are hired to temporarily backfill for those who have taken Field Service Representative or Project Temporary Installer positions, they will need to attend new hire meter reading training. As existing Meter Readers transition to Field Service Representative (FSR) positions, to backfill for those FSRs who have taken Project Temporary Installer positions, they will need to take classes focused on FSR field activities, including but not limited to the handling of billing inquiries and the use of various field tools such as those linked with customer service systems. Project Temporary Installers, who will handle the meter installations for the residential and less than 20 kW commercial accounts, will also need to undergo training that covers the meter installation procedures and practices as well as required training for field deployment activities and the use of our meter tracking systems.

B. Communications Infrastructure

The radio frequency communications system selected for AMI deployment will be comprised of collectors, packet routers, and Metricom Communication Controller (MCC) take-out points.[16] This AMI technology solution leverages and expands on our already-existing network. New collectors will be mounted primarily in the power space of a utility pole or streetlight and will communicate with the radios in the residential and small commercial meters to transmit meter data throughout the network to the MCC take-out points. In the RFI response, the vendor indicated that SCE would need to install 8,000 collectors throughout the service territory in order to achieve the 90 percent coverage requirement of full AMI deployment. Based upon our experience with the RF infrastructure currently operating within our service territory, we believe it is prudent to

[16] The AMI communications infrastructure is described in Appendix B.

install an additional 20 percent, or 1,600 collectors to achieve the 90 percent coverage assumed in the full deployment case. As such, our full deployment business case analysis assumes the installation of 9,600 collectors and the partial case assumes 928 collectors will be installed.

The meter technology for greater than 20 kW customers includes the use of a "radio under the meter cover" technology that will provide a RF "mesh-type" network of an additional 168,000 radios under full deployment (16,000 under partial deployment) to the overall AMI communications network. Given the heavy concentration of meters in both scenarios, we anticipate heavy congestion on the communications network, particularly for those locations in close proximity to the MCC take-out points. The installation of packet routers will help ease this congestion and ensure that data is transmitted to SCE's network in a timely manner so that it is available for bill calculation. We have assumed the installation of 96 packet routers for full deployment and 10 for partial deployment.

Installation of these MCC take-out points is required to collect the meter data and transmit it to our computing network where it can then be accessed for billing purposes. Under full deployment, we expect to supplement the existing 100 MCC take-out points we have in place today with 181 additional MCC take-out points. Under partial deployment, there will be 18 supplemental take-out points.

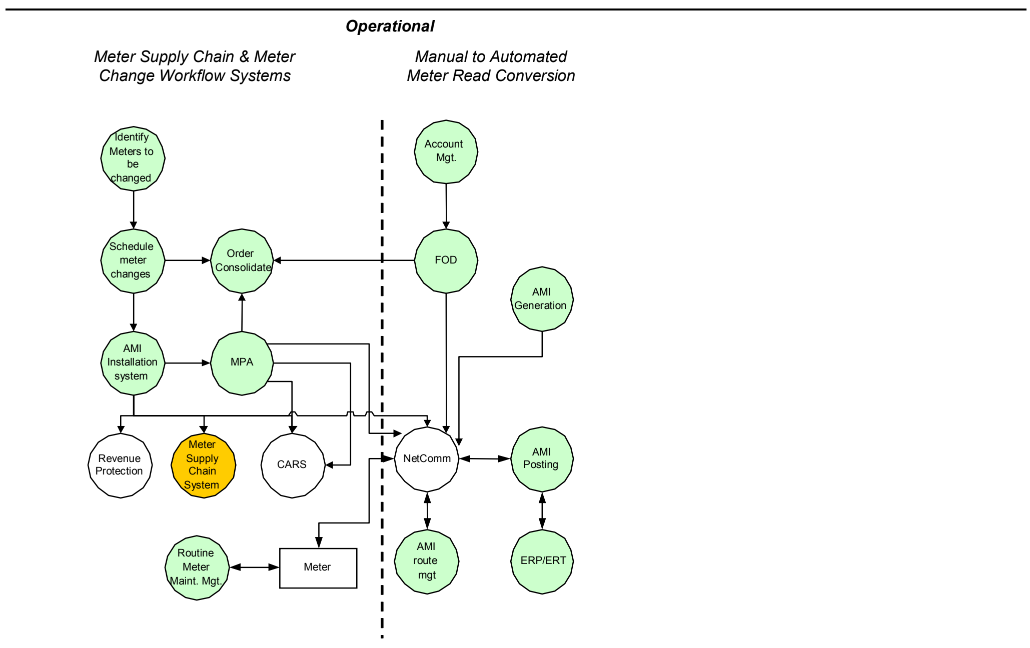
C. Information Technology Infrastructure

The Information Technology (IT) and Application cost category captures the costs associated with applications and computer services necessary to support AMI. These activities are described in more detail in the following two sections, the first relating to meter installation and meter reading applications, and the second relating to data management systems.

1. Meter Applications

Full deployment will require enhancement of certain existing meter management and meter reading data management systems, as well as development of new ones. Figure 3-1 illustrates the IT systems that will be required for AMI deployment.

Figure 3-1
Full AMI Deployment—IT Systems Architecture



The IT systems that need to be developed or enhanced to support AMI deployment are in the operational areas of meter supply chain management, meter change workflow, and meter read conversion. The following subsections briefly describe each of these operational areas and the systems that will be developed or enhanced to support AMI deployment.

a) Meter Supply Chain Management

We will utilize the existing Meter Supply Chain (MSC) system, with supplemented resources, as necessary, to assure that current procurement processes will meet the requirements of AMI deployment. These activities include but are not limited to, order and delivery tracking from the meter vendor, verifying receipt of the meters and reconciliation with the order, logging the meter as an SCE asset, testing of new meters, and distribution of meters from the Warehouse to Service Center locations for installation.

Under full deployment, each pallet of meters received from the vendor will be equipped with RFID tags. Upon receipt of the meters in SCE's warehouse, the RFID tags on the meters and pallets will be "read" into the system to verify and reconcile the order. RFID tags on individual meters will transmit unique asset identifications into the MSC system to track meters throughout the entire deployment workflow. The MSC system will register meters as SCE assets and manage the distribution of the meters to our service centers for installation. The RFID tracking system will not be utilized for partial deployment.

The MSC system will also be capable of interfacing with several related systems. For example, the MSC system will interface with the AMI Installation System, described later in this section, to pass meter delivery information automatically to the service centers. Further, the MSC system will interface with SCE's general ledger system to record new and retired asset information as meters are replaced and installed during full deployment.

b) Meter Change Workflow Systems

As shown in Figure 3-1 above, a new IT system will be needed to handle the meter change workflow process. This application will identify the meters that will be changed to AMI metering and will interface with the MSC system to identify the exact meters to be installed at each customer site. An additional application will be developed to track and schedule meter change orders. Our current Meter Process Automation (MPA) system handles meter change requests at an individual meter site level and cannot handle the significant volume of meters involved in full or partial deployment.

Under full deployment, the new Scheduling Meter Change (SMC) system will need to interface with the new AMI Route Management system that verifies that all meters for a route are, in fact, ready for AMI integration. The SMC system also automates the switching to the AMI network and will need to interface with the current Customer Data Acquisition Management (CDAM) system which maintains the route information. Building this interface will ensure that the SMC system efficiently schedules meter change orders. The new SMC system will also be used to track planning activities (*e.g.*, city or SCE field inspections) related to AMI meter installation. This system will have the ability to issue and cancel orders, as well as schedule appointments or reprioritize orders as field conditions warrant.

The AMI system will also interface with the SMC system to reschedule orders that were not completed. This system will also generate various exception situations that will require special processing. An order download/upload process will be built to perform interface functions between the host mainframe system and the Wireless Laptop System in the field. The users of the Wireless Laptop System will have the capability to view orders and input completion information. The Wireless Laptop System will also allow users to cancel or defer orders, if appropriate.

As a result of AMI deployment, a new system is required to interface with the existing MPA system which currently schedules, tracks, and posts data related to meter sets changes and removals. An Order Consolidation (OC) application will be developed to examine various meter orders for the same installed service account, to consolidate them, and maximize operational efficiency.

c) <u>Meter Read Conversion</u>

As shown in Figure 3-1, under AMI deployment, a number of new applications need to be developed to handle the meter read conversion. We expect that enhancements to the current Account Management (AM) system will be required. The AM system is responsible for various administration and maintenance activities associated with each customer's account. User functions will need to be modified to handle interval data usage. For example, the Bill Correction function will need to be changed so that users have the ability to input interval data usage in situations where the data is "missing" for certain periods of time. Another example of a user function requiring modification involves changing the data validations and prorating algorithms to handle interval data usage.

We also expect enhancements will be needed to the current Field Order Dispatch (FOD) system to accommodate the meter roll-out. The FOD system is currently responsible for the management of field visits related to metering and metered data communications and may include error detection, failures, and replacements. Enhancements are required to route field events from the FOD system to the AMI communications network support group and meter support groups.

AMI deployment will also require the development of a new system to monitor the status of accounts on each of the meter reading routes. This system will determine when all of the installed AMI meters on a particular route are communicating with the network. Once this new AMI Route Management system has validated that all newly installed AMI meters on a route are successfully communicating with the network, the meter reading route can then be switched to an AMI route and manual meter reading can cease.

We expect AMI deployment will require system modifications in order to generate requests for meter reads from the communications network. An AMI

Generation System will be developed to identify and generate accounts that are scheduled to be billed on any particular day. Based upon this data, the AMI Generation System will create requests for the network to gather meter data from these accounts so that bills can be prepared.

A new system is needed to collect meter read information from the AMI communications network, validate the data, and post the data in the Customer Service System (CSS) meter reading tables. If the data fails certain validations, the new AMI Posting system will generate a new exception to be included in the CSS exception table.

We anticipate that AMI deployment will require enhancements to the existing Exception Reporting and Routing (ERR) System, which is responsible for reporting, routing, and handling various exceptions. Enhancements will be made to the ERR System so that non-communicating equipment (meters, collectors, *etc.*) will be reported to the ERR system from the network through an electronic file. Additionally, enhancements to the ERR System will be developed to address new exceptions created by AMI processes. If exceptions cannot be resolved automatically by the ERR System, they will be routed to a bookkeeper for resolution.

Each of the new or enhanced systems represented in Figure 3-1 require computing services infrastructure to support all software supporting the collection and processing of AMI data. With the exception of RFID processing requirements, these services are the same for full and partial AMI deployment; although the magnitude and cost of these services is scaled back considerably for partial deployment. Computing Services includes the actual procurement, installation, and maintenance of the necessary infrastructure. Computing Services infrastructure and hardware additions fall into the following broad areas:

- Additional servers;
- Additional processors to increase MIPS on the mainframe;

- Additional processors to increase processing capacity on Reduced Instruction Set Computer (RISC) and Wintel systems;
- RFID tag reading equipment (full deployment only);
- Additional laptop and desktop computers;
- Additional Storage (DASD);
- Incremental personnel to manage installation of additional infrastructure;
- Additional operating system and database licenses; and
- Computer network upgrades.

2. Data Management Applications

The introduction of massive volumes of interval data will require enhancements to our Service Billing, Usage Calculation, Wholesale Settlement, and SCE.com systems. The discussion that follows provides a brief description of necessary enhancements to these systems.

a) Service Billing

Enhancements will need to be made to our Service Billing System, which provides the core functionality to calculate customer bills. The terms of each of the rate schedules are translated into "service plans" and stored within the Service Billing System. A service plan defines the types and levels of charges and specifies how a billing statement will be calculated for a service account. Under both the full and partial scenarios, new tariff schedules will be introduced. As a result, changes will need to be made to the Service Billing System to include the resulting service plans so that billing statements can be calculated.

b) Usage Calculation

A core system functionality needed to support AMI involves the processing of interval data. Currently, we have a fairly small-scale system, called the

Customer Data Acquisition system that handles calculating usage for existing customers with interval meter data. We will need to develop a new Usage Calculation System in order to handle the large volume of interval data that will be associated with the AMI deployment. As 15-minute data intervals are collected from meters, they will be transferred to the Usage Calculation System. The data will then be aggregated into values corresponding to the applicable season and time periods dictated by the terms of the service plan. Once aggregated, this data is transmitted to the Service Billing System for bill calculation and, in the full deployment scenario, to the Wholesale Settlement System for financial settlement.

c) Wholesale Settlement

Under the full deployment scenario, significant enhancements will need to be made to the Wholesale Settlement System. This system handles calculating various settlement charges related to power procurement activities with the California Independent System Operator (CAISO) and other counterparties. In the current system, the hourly usage values that are used to determine these settlement charges are calculated using load profiles, which are applied to monthly reads. Once AMI is fully operational, the usage data received for wholesale settlement will be actual interval usage data, replacing the use of load profiles. As such, under full deployment, the Wholesale Settlement System will need to be enhanced to handle the aggregation of the increased volume of actual interval usage data associated with the 4.5 million AMI meters. The data needs to be aggregated by customer class and associated with the appropriate generation schedule and generation resource usage data in order to calculate settlement charges. Under partial deployment, we will continue to use load profiles to determine CAISO settlement charges and no changes will be made to the Wholesale Settlement System.

d) SCE.com

Significant enhancements will need to be made to SCE.com in order to facilitate customer participation in demand response programs, as well as accommodate the expected increase in customer access. Currently, SCE.com provides customers with their monthly energy usage data and corresponding monthly costs. In terms of additional user functionality, residential customers will have the ability to view their hourly energy usage data from the previous day while commercial and industrial customers will be able to view 15 minute data intervals from the previous day. It is anticipated that customers will have access to available interval data for up to 13 months and will be able to view charts and graphs for comparing applicable data. Customers will also be able to access analytical tools to help them manage energy usage and control their energy-related costs. Customers will be able to view and monitor CPP rates and event details.

A key assumption driving the cost of these enhancements is related to the increased traffic expected on SCE.com. The concurrent website "hits" are expected to increase significantly, especially before, during or shortly after a critical peak event.

D. Customer Service Systems Category

This section describes the customer service operations, processes, and systems that are affected by AMI deployment. These changes are needed to sustain a high level of customer services throughout the installation phase of AMI deployment. Specifically, the customer services-related operations discussed in this section include Billing, Call Center, Meter Order Processing, and Customer Communications (Marketing) activities. This section will not discuss meter reading and field services activities, because these functions are covered in the Meter System Installation and Maintenance category discussed previously.

1. Description of Billing Activities Affected by AMI Deployment

SCE's Billing Organization currently processes and delivers over 56 million customer billing statements each year. For the most part, this process is automated and only a small percentage of the total bills produced require manual intervention. Historically, the two situations having the largest impact on the manual billing processes are meter changes and rate structure changes, both of which will occur in significant numbers under AMI deployment. Under full and partial deployment of AMI, we will need to convert the current billing system from one that depends primarily on monthly meter reads in the field to a system that will generate bills based almost entirely on hourly and 15-minute interval data transmitted daily through the network communications system. At the outset, we expect the need for start-up costs associated with the specification of security systems, the development of data retrieval strategies, network planning, and the meter RFP proposal specifications. Installation and on-going O&M costs are expected to result from a large increase in the number of billing exceptions that are expected to result due to meter changes, meter failures, communication system failures, and interval data processing.

a) Meter Change Exceptions

The largest effect of AMI deployment on the Billing Organization's operations and processes occurs during the installation phase and is a result of the mass exception processing that is expected to occur as meters are replaced. A small percentage of the replaced meters will result in billing-related problems (exceptions) requiring manual processing to assure timely and accurate billing. A variety of problems including broken or non-registering meters, mislabeled or switched meters, and missing meters (cut-in-flat services, *etc.*) are expected to be discovered. Though small in terms of percentage of the total, the initial replacement of such an unusually large quantity of meters will result in a significant increase in the number of billing exceptions being processed.

b) Meter Failure Exceptions

In addition to the 4.5 million original installations, under full deployment billing operations will be affected by the replacement of an additional 1.5 million meters due to meter and/or communication failures throughout the 15-year analysis period. Under partial deployment, in addition to the original 325,000 installations, approximately 144,000 failed meters will be replaced. We estimate that 50 percent of all meter failures will require exception processing. For full deployment, meter failures are expected to peak at 168,000 in 2007, and drop to 92,000 by 2010. For partial deployment, meter failures are expected to peak at 32,000 in 2007, and drop below 6,400 by 2011. We expect, however, that beyond the initial installation phase, meter failures will continue at a steady state rate of approximately two percent throughout the meter's useful service life.

When a meter fails in the middle of a billing period, a determination must be made as to how the affected bill (and subsequent bills) will be processed. With AMI metering, this process becomes considerably more complex because the affected account depends on the accuracy of interval consumption data. Depending on the nature of the meter failure, a judgment call is often required with regard to estimating consumption. This sometimes involves contacting the customer in order to assure a fair and equitable resolution. A similar process is followed when rate related billing exceptions occur.

c) Communication System Failures

Reading meters remotely adds a whole new layer of data quality concerns. These concerns are not only attributable to new meter technology, but also to the likelihood of communication system failures, which will inevitably occur. We know this from experience, not only with the recent implementation of RTEM, but from our earlier experience in implementing 350,000 van-based AMR meters. In order to sustain the current high level of billing accuracy and timeliness will require the development of new validation routines. For example, a simple comparison of the total of all interval consumption during a billing period may not match the difference between that months beginning and ending registration. This validation failure may trigger an automatic reread and, ultimately, a manual field inspection and “check read” to determine the nature of the problem. This situation may also require the use of a data “plugging” routine to automatically insert the missing interval data.

d) Interval Data

Under Scenarios 4 and 17, both of which include implementation of CPP rates, the processing of interval consumption data has a significant impact on billing costs because virtually all accounts will require interval data processing in order to determine consumption and demand readings by time period and/or during critical peak periods. The processing of interval usage data is vastly more complex than simple, monthly meter reads and requires an additional layer of validations and the resultant exception processing in order to assure the integrity of each 15-minute or hourly read and to assure that the summation of all interval consumption throughout the billing period does, in fact, match the difference between the meters starting and ending reads for the same period.

2. Description of Call Center Activities Affected by AMI Deployment

Our Call Center receives and handles over 11 million calls per year. Full deployment of AMI is expected to result in call volume increases of approximately 1 million calls during the peak year of deployment, then settle down to approximately 100,000 additional calls per year after 2010. Partial deployment of AMI is expected to result in a call volume increase of approximately 185,000 calls during the peak installation phase and settle down to approximately 6,000 additional calls per year for the duration of the project. This call volume increase is expected to result from customers calling to inquire about a variety of issues ranging from the new meter being installed to questions about the new tariff structures, including but not limited to questions about opting-out of the new CPP default rate. Our call volume estimate includes the number of customers who will opt-out, in addition to a number of customers who will call to inquire about opting out, but who ultimately choose to stay on the new rate. In determining the impacts on the Call Center operations due to full and partial AMI deployment, we estimated that 70 percent of the customers that call to inquire about opting-out would actually opt-out of the new tariffs. This estimate is based on our assumption that most customers who call to opt-out will have already made up their mind, however, with proper training of Call Center personnel, approximately 30 percent of such callers will be convinced to continue with the program.

We expect that once AMI is fully deployed and operational, call volume reductions will result from more accurate billing. Billing inquiries today are received for several reasons, one of which is an inaccurate meter read. Based on analysis of 2003 data, 22,791 calls were a result of meter reading errors. We used this number as a percentage of all calls to determine the percentage of calls that would be projected as meter read error calls. For the business case, we assumed that 100 percent of these calls would be avoided with automated meter reads. Ultimately, we expect call volume to be reduced by approximately 24,000 calls per year for full AMI deployment under Scenario 4 and 1,700 calls per year for partial deployment under Scenario 17.

E. Management and Miscellaneous

This section describes the overall Project Management and miscellaneous costs not included in other cost categories. Other costs include centralized training costs, personnel recruiting costs, employee communications, and miscellaneous start-up related costs. For the most part, these costs are categorized as "start-up" and "installation" costs. The

Billing Organization has identified some on-going O&M costs that are expected to continue through the duration of the analysis period.

1. Program Management

For full deployment scenario, a program management team consisting of eight SCE middle management and two SCE-staff support personnel will oversee the five and one-half year installation and system development phase of the full deployment project. After installation, one SCE Program Manager and two staff personnel will remain to oversee the program for the remainder of the analysis period. We also anticipate the need for as many as 18 contract personnel to support the program management effort in the initial year of installation (*i.e.*, 2006) dropping down to 12 for the remainder of the installation phase (*i.e.*, 2007 -2010). For the partial deployment scenario, a program management team consisting of eight SCE middle-management and two, SCE-staff, support personnel will oversee the one year installation and system development phase of the project. After installation, one SCE Program Manager and two staff personnel will remain to oversee the program through 2010. We also anticipate the need for as many as 10 contract personnel supporting the program management effort during the initial installation phase in 2006.

In addition, each of the major operating departments has estimated some project management costs to support the core project management team. We have also determined that in order to meet the deployment schedule proposed in the July 21, 2004 Ruling, with deployment starting in 2006 and full deployment by 2011, there will likely be project planning tasks that should occur even earlier. However, these earlier program management costs are not included in this filing.

2. Training Costs

Under the full deployment scenario, training costs would be incurred within each of the major operating organizations as well as at the corporate level within our centralized Job Skills Training (JST) Organization. Incremental training costs will be incurred not only for specialized instruction related to AMI metering activities and new rate options, but a significant part of the increased training cost will be more generalized, new-employee training. Our JST training includes the cost of curriculum development, preparation of training materials, and payment of instructors. JST training is primarily for new employees in the Meter Reading, Call Center and Billing organizations needed to meet the workload added during the installation phase of AMI. These costs do not include paying the employees themselves for the "seat time" spent in training sessions. Seat time costs are included in the cost estimates for each individual operating organization.

3. Customer Communications

During the installation phase, we expect only a minimum level of direct, customer communications costs beyond what we currently experience. If we are required to notify customers of planned meter changes, we expect to comply through a regular monthly bill insert or bill message. Any mass media or other outbound communications that the Commission directs is needed for purposes of public notification during the installation phase would add incrementally to our estimated costs. Once installations are complete and the new CPP rate goes into effect, a significant and sustained outreach campaign will be needed. The strategic approach of the campaign is to use an integrated mix of media designed to minimize the customer opt-out rate, retain customers on the CPP rate over time, and affect a long-term cultural and behavioral change for the purpose of maximizing demand reduction from participating customers. The campaign must be multi-year in order to positively affect long-term change.

a) Campaign Overview

Given the scope of the AMI effort, we need to develop and implement a multi-year campaign in order to positively affect long-term change and deliver the anticipated demand response levels over the full duration of the project. There are two strategic tenets of the campaign:

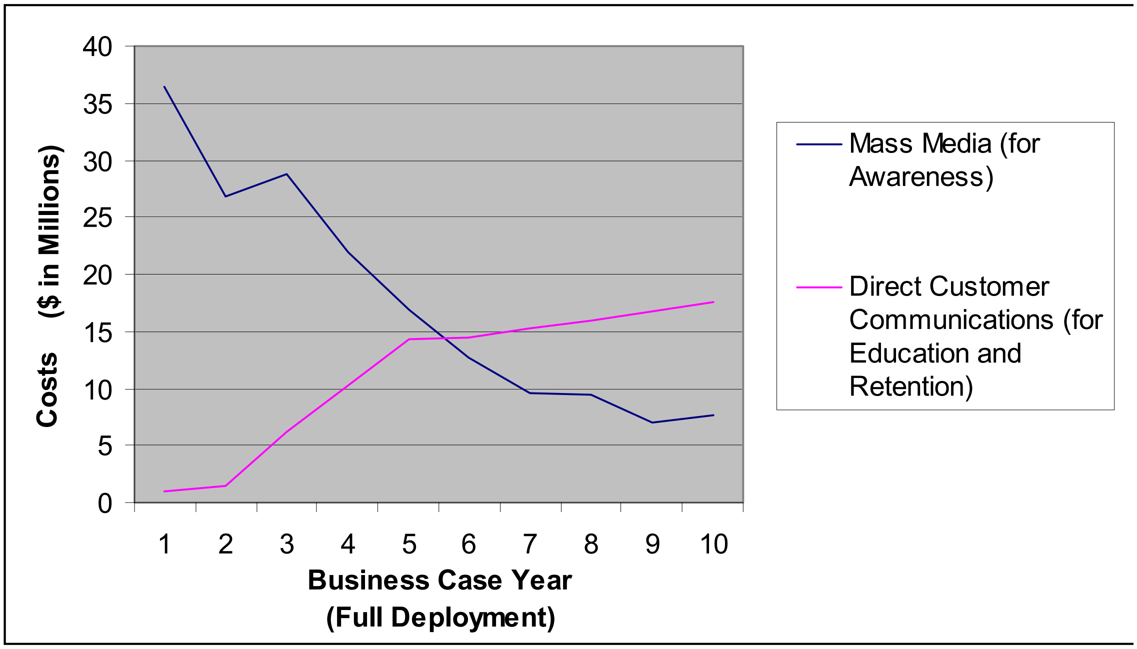
- Mass media will be utilized initially at “heavy” levels and over the life of campaign at “maintenance” levels, to build and maintain awareness about the program and to minimize the opt-out rate initially and over time, and

- Direct customer communications will be utilized throughout the life of the program. We expect to develop and implement a comprehensive educational campaign designed to help customers modify behavior while on the AMI program in order to maximize demand reduction from enrolled customers. We also plan to develop and implement a direct-communications retention campaign to maintain the customer base over time.

b) Communications Media

As shown in Figure 3-2, during the course of the campaign, the weight and mix of media and direct communications as well as the overall cost will change to reflect the communications support required.

Figure 3-2
AMI Customer Communications—Media and Direct Customer Communications Mix



To make outreach as effective as possible, we will conduct research with our customers to understand consumer attitudes and adapt messaging appropriately for all geographic and ethnic groups prior to the delivery of the campaign. Using this research, we will develop an on-going campaign that includes communication and outreach that is designed to reach 100 percent of our customers. We intend to saturate the customer base with a broad-based awareness and educational campaign, as well as specifics on how customers can respond to time-differentiated rates. The media mix we envision for the campaign includes mass media, targeted/ethnic media, direct communications, and "CPP Day" notification.

(1) Mass Media

Use of mass media will extend to television, radio, and print media for education and awareness. For example, for the general English-speaking market, we envision cable and/or television spots to run for 6-12 weeks over a 12-24 week time period where ads would be seen by targeted customers an average of two to four times per week, radio ads to run for two, 8-week periods, where ads would be heard by targeted customers approximately one time per week, and printed information to appear on ½ page inserts in daily, weekly, and monthly publications up to 12 times per year.

(2) Targeted/Ethnic Media

Use of this will extend to local print, cable television, and strategic partnerships (ethnic business chamber promotion) including the use of in-language media for education and awareness targeted to SCE's diverse customer base. For example, we envision cable and/or television, radio, and printed information to run on the same schedule as the schedule for the general English-speaking market, but be targeted to the appropriate ethnic-based media (*e.g.*, Asian, Spanish, and African-American) to reach SCE's diverse customer base.

(3) Direct Communications

Use of direct communications will include bill inserts, direct mail, e-mail notification, voice mail notification, newsletters, and face-to-face communication through the account management function. This will be used for retention and behavior change education meant to help customers maximize demand reduction. Specifically, we envision utilizing a variety of direct customer communication tactics staged over a designated period of time to maximize reaching our customers and the frequency with which they hear our education and retention messages, thus, driving behavior change.

(4) "CPP Day" Notification

We expect to use an automated phone messaging system and press releases/press relations to notify customers of CPP Demand Response events.

c) Campaign Goals and Objectives

The AMI media campaign will differ significantly from those previously undertaken by SCE. Previous campaigns were designed to create customer awareness and promote programs on a short-term basis. This campaign will utilize educational information and tools to help customers make the behavioral changes required to comply with the new CPP rate structure. The purpose of this campaign is to maximize demand reduction from participating customers, as well as create retention information designed to retain customers on these rates over time. Long-term customer enrollment and long-term behavioral and cultural change are essential to AMI's success. One of the two main objectives of the campaign is to teach customers about why CPP rates require a behavioral change and move them toward such behavioral change. Through education, we expect to achieve customer understanding of their energy usage and offer them information and tools to manage their usage under these pricing options. This will be achieved through the customer-specific education portions of the campaign. The campaign's other main objective is to minimize the customer opt-out rate and retain customers on the CPP-rate program over time. This will be accomplished through the customer-specific retention portion of the campaign.

The cost of this type of campaign is significantly affected by SCE's unique Southern California location as it relates to mass and in-language media costs. Our service territory sits in some of the most expensive advertising costs/media outlets in the United States. The greater Los Angeles area, including Climatic Zone 4 communities, is the second largest and highest cost media market in the country. It is also both linguistically and culturally diverse.[17] As such, messages must be created and delivered in languages other than English. Additionally, 35 percent of our customer base has

[17] 2003–2004 Nielson Universe Estimates, DMA Ranking and Advertising Age Magazine, July 24, 2000

demonstrated a lack of interest in electricity issues other than when their power goes out.[18] Customer communications must break through this demonstrated low level of interest and be accomplished through a variety of linguistically and culturally appropriate approaches to properly address various Asian, Spanish-speaking, and African-American communities, as well as the general population.

Our forecasted average, yearly, media and advertising costs related to customer communications and education for the Demand Response scenarios are close in comparison to media and advertising costs for other utilities (such as telecommunications utilities) in the Los Angeles Designated Market Area.[19]

4. Management and Miscellaneous Other Costs

This cost category includes other areas where miscellaneous costs have been identified. These include overseeing the vendor request for proposals (RFP) process, contracts supervision, employee communications costs, personnel recruiting, and employee training and communications relating to customers' access to their own energy usage data. Other management overhead costs spanning two or more functional cost categories, such as project management and the administration of job skills training, are also included in this cost category.

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[18] ARD0075 Residential Segmentation: Southern California Edison Customer Segmentation Research, December 2003.

[19] 2004, Nielson Media Research.

IV.

BEST FULL DEPLOYMENT BUSINESS CASE ANALYSIS (SCENARIO 4)

This section provides our full deployment business case analysis for the "best case" Scenario (Scenario 4) as presented in our January 12, 2005, compliance filing. The following sections describe the costs and benefits we expect will result from implementation of this scenario. These costs and benefits are described as "incremental" to our "Business As Usual" case, as presented in Appendix G. As previously described, "full deployment" means replacing 97 percent of our existing 4.7 million meters over a five-year time period, and building the communications infrastructure to allow us to read at least 90 percent of these meters remotely.

These costs and benefits have been quantified using the July 21, 2004 Ruling's assigned cost and benefit codes. We also present a discussion of the uncertainties and risk analysis for this scenario, as well as a discussion of the NPV analysis. The operational activities, processes, and procedures affected by full deployment under this particular scenario were fully discussed in Section III above.

The default rate for Scenario 4 is CPP-F for residential customers, and CPP-V for C&I customers. Scenario 4 results are summarized in Table 3-6.

Table 3-6
Summary of Cost/Benefit Analysis for Scenario 4
($Millions)

Costs	Benefits	Pre-tax Sub-Total	After-Tax NPV	Rev. Req. Present Value
($1,298.4)	$804.6	($493.8)	($402.9)	($951,815)

A. Costs

Appendix A to the July 21, 2004 Ruling separates AMI deployment costs into six broad cost categories: (i) Meter System Installation and Maintenance, (ii) Communication Systems, (iii) Information Technology and Applications, (iv) Customer Services, (v) Management and Other, and (vi) gas service costs (which are not applicable to SCE). The July 21, 2004 Ruling also establishes 79 different cost codes applicable to these cost categories that must be used for analytical purposes. Under this full deployment scenario, we expect to spend a total of $1.3 billion, including operational and capital investment related costs.[20] Table 3-7 below summarizes our estimated costs in the five cost categories.

Table 3-7
Summary of Costs for Scenario 4
(000s in 2004 Pre-Tax Present Value Dollars)

Line No.	Cost Categories	Total
1	Metering System Infrastructure	$668,399
2	Communications Infrastructure	41,974
3	Information Technology Infrastructure	206,003
4	Customer Service Systems	211,459
5	Management and Miscellaneous Other	170,578
6	**TOTAL**:	$1,298,413

1. Meter System Installation and Maintenance

The July 21, 2004 Ruling's MS-1 through MS-11 cost codes correspond to the costs associated with procurement, supply chain management, meter testing, installation and associated support costs. The following subsections describe our analysis of the costs falling into each of those cost codes.

[20] As specified in the July 21, 2004 Ruling, all costs are presented in 2004 pre-tax present value dollars unless otherwise stated.

a) Meter Reader Transition Costs (MS-1)

For the 24 service centers in our metropolitan areas, we assume that current FSRs and Meter Readers will be selected for the Project Temporary Installer positions, as discussed further in cost code MS-5. A number of our existing Meter Readers will be upgraded and trained to fill the positions of the FSRs placed in the Project Temporary Installer positions. There will also be vacancies in the Meter Reading staff as existing Meter Readers fill new positions such as supervisors, revenue protection investigators and administrative staff needed to support the AMI deployment. Beginning in 2006, we estimate that we will have 288 vacancies in our meter reading staff caused by employee movement to other areas supporting AMI deployment. We plan to fill those vacancies by staggered replacement through the third quarter of 2006.

A critical factor considered when filling these positions is the productivity differential between a new meter reader and an experienced meter reader. During the first month, we assume that new Meter Readers will perform at 60 percent of the productivity standard of experienced Meter Readers. Their performance steadily increases and by their sixth month, new Meter Readers must perform at similar productivity standards as an experienced Meter Reader. Given this productivity differential, we will need to hire 104 additional project temporary Meter Readers during 2006 in order to achieve the same levels of productivity we would achieve with an experienced Meter Reading staff. We assume that these 104 incremental Meter Readers leave the organization through attrition as productivity increases by the end of 2006. Accordingly, the anticipated Meter Reader transition cost in 2006 is $5.9 million.

For the 10 service centers in our rural areas, we will be relying on our existing FSRs to handle installations. Existing Meter Readers will be upgraded and trained to handle FSR job responsibilities to fill in for FSRs taking the Project Temporary Installer positions. We plan to fill the vacancies in our Meter Reading staff with project temporary Meter Readers. We estimate that we will need eight project temporary Meter Readers throughout the 2006 to 2010 deployment period at a cost of $2.0 million.

The reduction of 80 percent of our current meter reading organization is expected to take place through normal attrition during the latter phases of AMI deployment. Our current attrition rate is 35 to 40 percent annually. Attrition is expected to ramp-up beginning with the activation of the AMI communications system (approximately 18 months after AMI installations begin) and continue throughout the deployment years. Severance of 32 supervisory personnel will result in a one-time cost of $1.9 million in present value dollars.

b) Supervision of Installer Workforce (MS-2)

With the addition of new staff (as discussed in the cost category descriptions for MS-1, MS-5, and MS-12), we will need to hire additional supervisors and support personnel. We forecast a need to hire an additional FSR supervisor in each of the 24 service centers in the metropolitan area. An additional Supervising Field Service Representative will be hired for each of the service centers to handle the rerouting of the remaining manual read accounts, oversee the distribution of work, and oversee the resolution of access issues. We also forecast that one administrative aide will be needed for each service center to handle customer contacts, arrange customer appointments and handle administrative personnel-related activities. We also expect to hire three project support personnel to assist with deployment tracking and reporting for all of our service centers in the metropolitan and rural areas. Finally, we expect to add one supervisor and one project manager to handle the new revenue protection investigators that will be hired (as discussed in cost code MS-12). TDBU also requires one additional FTE in the rural districts. We estimate the cost of these 78 incremental employees at $25.2 million over the 2006 to 2010 deployment timeframe.

c) Cost of Purchasing Meters (MS-3)

Based on vendors' RFI responses, our preliminary estimate is that we will procure approximately 6.7 million meters at a cost of $431 million over the 2006 to 2021 timeframe resulting from the initial AMI deployment, replacing meter failures, and addressing customer growth. We will procure four different meter types for the AMI deployment. Each meter will be equipped with an RFID tag to facilitate our procurement and supply chain processes. The RFID tag adds $2 per meter to the cost. Sales tax was included in our estimated meter cost.

To achieve the 90 percent coverage required by the July 21, 2004 Ruling, we will procure 4.5 million meters to replace the existing meters throughout our service territory. Table 3-8 shows the types of meters, quantities, and unit costs associated with full deployment.

Table 3-8
Cost Table for Initial AMI Full Deployment Meter Purchases

Meter Type With Communication Module	Meter Quantity	Base Unit Cost
< 20 kW residential single phase	4,112,000	$52
< 20 kW network	117,000	$132
< 20 kW 3 phase commercial and residential	182,000	$322
> 20 kW commercial	129,000	$702
TOTAL	4,540,000	N/A

We will also incur meter equipment costs in addition to the AMI meter and RFID costs. We assume that each AMI meter will need to have a meter lock ring. We expect to be able to use 50 percent of the lock rings currently in place for the new AMI meters, however, these lock rings will need a new lock pin. Thus, we will need to procure new lock rings for 50 percent of the new AMI meters, and we will need to procure new lock pins for the other 50 percent. Another additional cost we expect to incur is associated with replacing the current A-base meters. For these meters, we must install an adapter to enable the meter change.

Our preliminary analysis shows that during full deployment, we will have meters that fail after the three-year warranty period has expired. We estimate that there will be 962,000 meter failures during the 2009 to 2021 timeframe based on our projected failure rate.[21] In those cases, we will need to procure and install new AMI meters at these meter sites. Table 3-9 illustrates the meter type and expected volumes associated with replacing these failed meters.

Table 3-9
Meter Failures - Out of Warranty Only (Scenario 4)
(2009 Through 2021)

Meter Type With Communication Module	Quantity
< 20 kW residential single phase	871,000
< 20 kW network	25,000
< 20 kW 3 phase commercial and residential	39,000
> 20 kW commercial	27,000
TOTAL	962,000

In addition to installing AMI meters on existing meter sites, we will need to install AMI meters as we experience customer growth. We estimate approximately 1.2 million new meter sets during the 2006 to 2021 timeframe due to customer growth. Table 3-10 shows the expected meter type and volumes associated with these new meter sets.

[21] *See* Appendix C concerning how this failure rate was calculated.

Table 3-10 Cost Table for Projected Meter Growth (2006 Through 2021)	
Meter Type With Communication Module	**Quantity**
< 20 kW residential single phase	1,053,000
< 20 kW network	30,000
< 20 kW 3 phase commercial and residential	47,000
> 20 kW commercial	33,000
TOTAL	1,163,000

d) Installation and Testing Equipment Costs (MS-4)

Our analysis indicates that we will incur $24.5 million in installation and testing equipment costs during the 2006 to 2021 timeframe. With regard to installation equipment, over the 2006 to 2010 timeframe, we will incur costs for tools, equipment, materials, supplies, uniforms, and vehicles associated with the new installers, meter technicians, meter readers, field service representatives, supervisors, and various support personnel. These costs will continue over the 2011 to 2021 time period for the incremental personnel remaining following the installation period.

We will also incur facility costs over the 2006 to 2010 timeframe. Current SCE service center facilities cannot house the required incremental personnel. Facilities will either be modified to handle the incremental personnel or portable facilities will be leased.

In terms of meter testing equipment costs, we will incur costs to reconfigure our Meter Shop facility to handle the increased workload for the AMI deployment. Seven additional meter test workstations must be installed in the Meter Shop during the 2006 to 2007 timeframe. In addition, our material handling conveyer system needs to be upgraded because the existing conveyor will not accommodate additional workstations. We will also need to acquire an additional demand testing board to handle the increased workload for commercial meters.

e) Installation Labor (MS-5)

(1) Residential and Small Commercial (<20 kW) Meters

In order to support the aggressive deployment schedule set forth in the July 21, 2004 Ruling, we estimate a need for 202 Project Temporary Installers during the 2006 to 2010 timeframe. We base this estimate on the assumption that an installer in our metropolitan areas will install 25 residential meters per day or 18 commercial/industrial meters per day.[22] The cost of additional personnel to perform these installations is estimated to be $55 million over the 2006 to 2010 timeframe.

(2) Complex Meters

In our service territory, we have approximately 275,000 meters that are considered complex and installations will, therefore, be handled by Meter Technicians. Given the aggressive deployment schedule required by the July 21, 2004 Ruling, we will rely on both full-time resources and contract resources. Beginning in 2006, we will dedicate 87 Meter Technicians to full deployment. As the five-year deployment period progresses, we will decrease resources dedicated to the project. These resources will also need to work overtime in order to meet the annual installation targets. We have estimated that the overtime to be worked is equivalent to between 13 and 30 incremental full-time employees throughout the 2006 to 2010 timeframe. Our personnel estimates are based upon the assumption that a Meter Technician can install an AMI meter in 2.5 hours on average. The cost for the additional personnel is estimated to be $32.0 million over the 2006 to 2010 timeframe.

[22] Installation rates for the 104,256 meters covered by the rural installers are different because of the vast difference in geographic locations between meters. We estimate that rural installers will install 20 residential meters per day and five commercial/industrial meters per day.

We expect to employ outside contractors to assist with the installations beginning in 2007. The number of contractors will vary by year, ranging from 12 contractors in 2007 to 22 contractors in 2009. The costs associated with the contract employees are $4.6 million over the 2007 to 2010 timeframe.

f) Meter Installation Tracking System (MS-6)

We expect there will be meter failures that occur throughout the deployment period. We plan to hire additional analysts as necessary to assist with tracking the meter failures. The analysts will look for trends in the failure data so that we can resolve communication or product issues with the vendor. We estimate the cost for this additional activity at approximately $0.61 million for the period 2006 through 2010.

g) Panel Reconfiguration/Replacement (MS-7)

When we replace A-base meters during the course of deployment, we will need to install a socket adaptor in the panel. This socket adaptor allows the new AMI meter to be "plugged" into a customer's older electrical panel. We assume that fewer than two percent of all meter changes in any given year will be A-base meters requiring the socket adaptor. In addition, during the installation process, our installers may inadvertently damage the customer's meter panel. Although the meter panel is the customer's responsibility, we intend to pay the costs for any damages that occur to the panel while we perform the installation work. Based on our experience installing over 350,000 AMR meters, we incurred approximately $50,000 in damages associated with customer panels. For purposes of this business case analysis, we relied on this experience to develop a per meter damage cost of $0.14. Accordingly, the costs associated with panel reconfiguration/replacement are estimated to be $2.1 million over the 2006 to 2010 timeframe.

h) Potential Customer Claims (MS-8)

We expect to incur costs related to potential customer claims as a result of the AMI deployment. However, for purposes of this analysis, these costs have been reflected as part of the cost estimate for cost code MS-7 given that we were not able to delineate the customer claim-related portion of the costs.

i) Salvage/Disposal of Removed Meters (MS-9)

As installers remove non-AMI meters, they will return these meters to the service centers. We plan to contract with a salvage company to handle removing these meters from each of our service centers. As such, we have not assumed any incremental costs to handle these meters.

Throughout the meter deployment period, we anticipate that there will be meter failures in the field. Once the installer returns the meter to the service center, the meters that are still under warranty will be returned to the vendor for replacement. We will require additional personnel to handle the processing of meters returned to the vendor. Over the 2006 to 2010 deployment period, we estimate $0.63 million in labor costs for this activity.

j) Supply Chain Management (MS-10)

As discussed in Section III of this volume, our PAMM group is responsible for receiving and stocking meters at our central distribution facility. We expect to add more personnel to handle the increased volume of meters that will be received and processed in the central distribution facility. During the 2006 to 2010 deployment period, we estimate the need for nine material handlers responsible for receiving the meters from delivery trucks, storing the meters within the warehouse, and staging the meters for distribution. We also forecast the need for three warehouse clerks to maintain the integrity of the inventory by processing receipts, conducting inventories, and tracking assets. We will need two heavy-transportation drivers to deliver new AMI meters to our Meter Shop for testing and then out to the various SCE service centers for installation. Further, we anticipate the need for additional supervisory and project support personnel. Throughout the 2011 to 2021 time period, we will maintain additional personnel to process the meter failures in the field. This processing includes sorting, packaging, and shipping the meters back to the supplier, as well as receiving and tracking the meters when they are returned. We estimate the cost for the additional personnel at $7.9 million over the 2006 to 2021 timeframe.

Currently, our central distribution facility is at 95 percent capacity, housing and maintaining a monthly average of 25,000 meters. With full AMI deployment, we expect to increase our meter inventory to 100,000 meters monthly. A new facility will be required to house the meter inventory because our current facility cannot accommodate the volume of meters required for this deployment.[23] Given the forecast monthly meter volumes, we expect to maintain this facility until mid-2011. Other non-labor costs that we will incur from 2006 to 2021 are for miscellaneous equipment, packing supplies, and freight costs for delivering materials to the service centers on a just-in-time basis. Thus, estimated non-labor cost is $8.0 million over the 2006 to 2021 timeframe.

As meters are delivered to various service centers, additional personnel are required to process the meters at the service center locations. This processing includes verifying receipt of the meter, scanning them into the Field Tracking tool, and resolving variances in expected versus actual deliveries. We estimate the need for 15 additional employees to handle these activities at an estimated cost of $5.2 million over the 2006 to 2010 timeframe.

[23] The start-up costs for a new facility are detailed below in cost category MS-11.

k) Training (Meter Installers, Handlers and Shippers) (MS-11)

For employee training needs, we looked at both the trainee-related cost of non-productive (seat) time spent in the classroom, as well as the cost of the trainer and training staff. Depending upon an employee's position, they will have to take training classes, ranging from new hire meter reading classes to meter installation classes. We estimate that the seat time costs for our field personnel will be $4.8 million over the 2006 to 2010 timeframe. The cost associated with developing and delivering materials for these training classes is estimated to cost $1.0 million over the 2006 to 2007 timeframe.

It is expected that most of the PAMM employees assigned to the AMI project will be new hires and will require training in all aspects of logistics including but not limited to: safety, systems, equipment, procedures and processes. Our PAMM Organization estimates training costs of approximately $426,000. As mentioned in cost code MS-10, our current central distribution facility is at 95 percent capacity and a new facility will be needed to house the meter inventory. In addition to the actual facility leasing costs, we will incur equipment and supply costs to connect the new facility with our existing communications network. We estimate that we will incur approximately $484,000 in 2006 to make this facility operational.

l) Maintaining Existing Metering Systems (MS-12)

As meter failures occur throughout the deployment period, replacement meters will need to be installed. FSRs will handle this work. We estimate the need to hire additional FSRs beginning in 2006 to support the meter replacement activities. Our personnel estimates include costs for 3.1 FTEs in 2006, increasing to 28.8 FTEs in 2007, and then decreasing to 15.4 FTEs in 2010. From 2011 to 2021, FTEs increase by 17 supervisor positions to reach a steady level of 32.5 FTEs. These new supervisor positions added in 2011 are a higher classification of supervisor due to the increased responsibilities of supervising a combined work force of 20 percent meter readers and 75 percent FSRs. In 2010, all 32 lower level supervisors are reduced in MS-1. Our personnel estimates are based upon a replacement rate of 25 residential meters per day and 18 commercial/industrial meters per day.

Throughout the full deployment of AMI, we expect that our installers may discover potential energy theft situations that need further investigation. This assumption is based upon our experience with the van-based AMR deployment. We plan to hire additional revenue protection investigators responsible for investigating these potential theft situations. With the increased potential for identification of possible theft, we expect to increase our current investigator staff from 16 to 32 investigators by 2007.

Currently, potential energy theft situations are usually brought to our attention by our meter reading staff. Given that a majority of the meter reading staff will be eliminated with AMI, we will hire three additional support personnel to analyze meter data to identify potential theft situations to be further investigated.

The labor costs for incremental FSRs, revenue protection investigators and associated support personnel are estimated at $37.9 million for the 2006 to 2021 timeframe. In addition to labor costs, we will also incur equipment costs of approximately $4.7 million for the same period for tools, equipment, materials, supplies, uniforms, and vehicle costs associated with the new FSRs, revenue protection investigators and support personnel.

Additional non-labor costs are forecast for battery replacements in the AMI meters installed on the greater than 20 kW commercial accounts. Those meters contain a battery with a 10-year life. In 2016, we will begin the process of replacing these batteries and the replacement process will continue through 2021. We estimate the cost of the replacement batteries at $0.40 million.

As the AMI system is deployed, we anticipate new issues will develop from the implementation of new systems and the large number of meter changes. These will impact our ability to prepare and deliver accurate customer bills in a timely manner.

We estimate the need for one FTE per year for project support to resolve AMI issues affecting billing. The estimated cost of this activity is $1.3 million over the 2006 to 2021 timeframe.

m) Pick-up Reads (MS-13)

When a meter fails, the failure can be attributed to either a registration issue or a communication issue. In either case, it will be necessary to send a Meter Reader to collect a pick-up read from that meter in order to maintain timely and accurate customer billing. We estimate that we will need to hire additional Meter Readers beginning in 2006 for such pick-up reads. Our personnel estimates increase in 2007 once the communication network is operational and we start experiencing both registration and communication failures with the AMI meters. Our personnel estimates include costs for 1.3 FTEs in 2006, peaking at 18 FTEs in 2007, and reaching a steady state of 6.7 FTEs from 2011 to 2021. These estimates are based upon a pick-up read rate of 56 reads per day. The labor costs for this cost code are estimated to be $6.0 million over the 2006 to 2021 timeframe. Non-labor costs of $0.8 million will be incurred for tools, equipment, materials, supplies, uniforms and vehicle costs associated with these new Meter Readers.

n) Meter Replacement Costs (MS-14)

As we described in cost code MS-12, we will need to replace the batteries for the AMI meters that are installed on the greater than 20 kW commercial accounts. The labor costs to perform this battery replacement are captured in cost code MS-14. Our estimates of $2.8 million include costs for 12 FTEs in 2016, peaking at 20 FTEs in 2020, and tapering off to 2 FTEs in 2021.

2. Communications System

a) Review/Specify Security System (C-1)

As we design our new communications infrastructure, it will be necessary to assess the systems needed to ensure the security of the data transmitted within the network. We plan to engage contractor resources to assist us with this assessment. The costs for this assessment will be incurred in 2006 and are estimated to be $72,800 in 2004 PV dollars.

To ensure the accurate transmission of data from the meter to the billing systems, we will dedicate personnel to review the operational design and system requirements. We estimate the need for additional personnel for these activities from 2006 to 2008 timeframe at a cost of $0.58 million.

b) Network Placement Site Surveys (C-2)

There are no incremental costs associated with this cost category.

c) Mapping Network Equipment on Company Facilities (C-3)

We will incur incremental labor costs during the 2006 to 2007 installation timeframe necessary to map MCC take-out point installations. Engineers will need to determine appropriate placement of the 181 MCC take-out points within SCE's service territory. Once the MCC take-out point locations have been identified by the engineers, communication technicians will be responsible for installing the equipment. The labor costs associated with replacing failed MCC take-out points are also included in the estimate for this cost category. Overall, we estimate the labor costs for these activities at $1.26 million.

We plan to utilize contract personnel to handle the installation of the collectors, packet routers and the antennas for the MCC take-out points throughout the entire deployment period. The contract personnel will handle the replacement of any failed equipment as well. Contract personnel will also be utilized during the battery change-out process, which is described in more detail below. The contractor labor and vehicle costs associated with these activities are $5.0 million.

d) Staging Facilities for WAN/LAN Equipment and Mounting Hardware (C-4)

For the communications infrastructure, we will configure and test 100 percent of the network infrastructure equipment before it is deployed to the field for installation. The labor costs associated with performing these activities on 9,600 collectors, 96 packet routers, and 181 MCC take-out points are estimated at approximately $0.96 million for the 2006 to 2010 deployment period.

In terms of maintaining the communications infrastructure, we currently do not have a facility that can accommodate the 85 FTEs needed to maintain the communications network (these personnel costs are further described in cost category I-15) below. Our cost estimates includes the lease costs for a new facility which will continue over the 2006 to 2021 time period. In 2006, we will incur facility set-up charges such as costs to connect the new facility to our existing communications network. Overall, the costs associated with this facility are estimated at $3.5 million over the 2006 to 2021 timeframe.

e) Review/Develop Strategies to Retrieve/Process Data from Meters (C-5)

In determining the appropriate strategies for retrieving and processing meter data, we evaluated IT application solutions. Given the data retrieval and processing requirements associated with AMI, we developed new applications or, in some cases, enhanced existing applications to handle these requirements. Section III above, details the various IT application solutions that need to be developed or enhanced in the areas of meter supply chain management, meter change workflow and meter read conversion. We have estimated approximately $0.37 million in contractor costs associated with the IT application solution design.

Our Billing and IT organizations will work jointly to determine the system requirements needed to prepare and deliver accurate bills in a timely manner based on data retrieval from AMI meters. We estimate $1.99 million in project management and business analyst support labor costs for these activities.

f) Auxiliary Equipment (C-6)

Our analysis indicates that we will incur $4.4 million in auxiliary IT equipment costs over the 2006 to 2021 timeframe. With regard to the communications infrastructure, auxiliary equipment for the MCC take-out points and collectors is required in order to make the infrastructure operational. For the 181 MCC take-out points, antennas and various other pieces of equipment will need to be installed on each unit. Each of the 9,600 collectors will be equipped with a battery, which is estimated to have a six-year life. This battery is required so that data is not lost in the event of a power failure. Beginning in 2012, we will need to begin changing the batteries in the collectors. In order to minimize installation error, we will provide the contractor personnel handling the equipment in the field with refurbished equipment that allows them to avoid changing the batteries in the field. In 2012, we will purchase 100 new collectors to begin this battery replacement process. The collectors that are removed from the network will be retrofitted with the new batteries and then redeployed to the field.

For the AMI meter installations, there will be a subset of meters that require an external antenna installation so that the meter can communicate properly with SCE's network. We assumed in our preliminary analysis that, based on information from the RFI response, one percent of all residential and less than 20 kW commercial meter installations will require an external antenna. For greater than 20 kW commercial meter installations, we estimate that 20 percent of the installed meters will require an external antenna. This assumption is based upon our experience with the RTEM Project. The majority of the antenna costs will be incurred during the initial deployment period in the 2006 to 2010 timeframe. However, the costs will continue through 2021 to reflect antenna costs associated with the loss of communication due to RF interference. Overall, we estimate the cost at $7.8 million over the 2006 to 2021 timeframe.

g) Pole Replacement (C-7)

We do not forecast any pole replacement requirements to support full deployment and thus we do not estimate any costs for this cost code.

h) Communications Link from Meters to Data Center; WAN/LAN Service (C-8)

We do not forecast any incremental costs for this cost code.

i) Install Cross Arms/Mounting (C-9)

We do not forecast any incremental costs for this cost code.

j) Purchase Network Communication Equipment and Hardware (C-10)

Over the five-year deployment period, we plan to install 9,600 collectors. The majority of the installations will be complete by July 2007, at which time the network will become operational. Once the RF networks are operational, we will be able to determine the specific areas within our service territory that are not communicating with the network and determine whether a collector can be deployed to cover that location or whether it will be a RF "blind spot," and will not possess remote read capability. We also plan to install 96 packet routers. We will need to install packet routers to ease congestion on the network and enable data to be transmitted to the network in a timely manner. Equipment costs for the 181 MCC take-out points are also included in this cost code. Each MCC take-out point will need to have four radios installed to make the unit operational.[24] Overall, the estimated costs for the network communication equipment are $13.8 million.

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[24] Other equipment is also needed to make the MCC take-out point operational. The costs associated with this equipment are discussed above in cost code C-6.

Table 3-11 describes the annual deployment volumes associated with the communication infrastructure.

Table 3-11 Communications Infrastructure Deployment Volumes					
Equipment	**2006**	**2007**	**2008**	**2009**	**2010**
Collectors	5,333	2,902	455	455	455
Packet Routers	62	34	0	0	0
MCCs	120	61	0	0	0

Throughout the course of the full AMI deployment, we expect equipment failures to occur. These failures will require us to incur additional labor and material costs to replace this failed equipment. Based on information from the RFI response, we assumed an annual equipment failure rate of one-half of one percent in our preliminary analysis.

As meters are installed, the installers and meter technicians will utilize an RF tool to verify that the communication module is functioning properly. We will also procure LAN assessment tools to help troubleshoot problems when we determine meters are not communicating with the network. We estimate costs for procuring this equipment in 2006 at $0.23 million.

k) WAN/LAN Training (C-11)

We do not forecast any incremental costs for this cost code.

l) Cost of Attaching Communication Concentrators (C-12)

Non-labor costs of $49,700 are included in this cost code for various development tools, licenses, and fees.

m) Contracts to Retrieve Meter Data (C-13)

We do not forecast the need for contracts to retrieve the meter data and services and have not forecast any incremental costs for this cost code.

n) Dispatch and O&M of Field WAN/LAN and Infrastructure Equipment (C-14)

We do not forecast any incremental costs for this cost code because there are no dispatch and O&M costs associated with infrastructure equipment.

o) Electric Power for LAN/WAN Equipment and/or Meter Modules (C-15)

We do not forecast any incremental costs for this cost code.

3. Information Technology and Application

a) Network Planning/Engineering (I-1)

As discussed above, we will install a communications infrastructure comprised of collectors, MCC take-out points, and packet routers. Thus, we expect to incur incremental labor costs of $2.8 million over the 2006 to 2010 period in this cost code for the engineers and project support staff to design this infrastructure.

b) Computer System Set-up (I-2)

Full deployment of AMI will require us to enhance our computing systems through the development of new applications and the enhancement of existing applications. To accommodate these changes to our computing infrastructure, new hardware and operating systems, including 134 servers and 2,965 Gb storage, will be required. Because we plan to use the RFID technology in our supply chain management activities, we will need to acquire equipment to make this technology operational. The equipment we will procure includes dock door portals, barcode readers, hand-held readers and laptops. Additionally, we expect to automate the asset tracking and work order aspects of the meter installation and removal processes. This will require us to upgrade existing field laptops and provide additional laptops with GPS capability for the installers.

Given the data processing requirements associated with interval usage data, we will also need to increase the mainframe resources by 1,025 MIPS and 1,379 Gb in additional storage.

Another major cost driver in this cost category is related to customer bill printing. As new rate schedules are introduced to facilitate customers' demand response, we are expecting that the number of pages of our customer bill will increase from four to six. In order to control our postage cost increases, we will need to maintain the current number of pages by printing on both the front and back of the bill stock. Our current printers do not accommodate printing bills in this manner. As such, new duplex printers will be required to process these new six-page bills.

In Scenario 4, to facilitate demand response, we will be posting customers' usage data on SCE.com, as discussed in further detail below. Upgrades will need to be made to the SCE.com servers in order to accommodate additional customers accessing our webpage.

Incremental SCE FTEs and contractor resources will be required to handle the design and installation of the new hardware. We estimate the costs for computing systems set-up and associated labor at $43.5 million.

c) Data Center Facilities (I-3)

As discussed in cost code I-2, we will be procuring duplex printers. Due to the size of the duplex printers, we will need to incur additional charges related to facility modifications. Non-labor costs of $92,500 are being charged to this cost code in 2006.

d) Develop/Process Rates in CIS (I-4)

Full AMI deployment will require us to develop new applications and enhancements to existing applications to properly support processes such as meter supply chain management, meter change workflow, and meter read conversion processes. A critical element of this effort will involve verifying that the new application or enhancement does not adversely affect existing systems that process meter changes and meter reads and calculate bills. We plan to use various comprehensive (and generally accepted) testing techniques, such as regression, integration, unit, and system testing. We will engage contractor resources to handle these testing activities during 2006. We estimate the cost for these activities at approximately $0.22 million.

e) New Information Management Software Applications (I-5)

Full AMI deployment will require us to automate the procurement processes in our Meter Supply Chain System. Analysis for this cost code assumes that the Meter Supply Chain automation project described in the 2006 GRC is deemed reasonable and receives cost recovery.[25]

The major drivers for the Meter Supply Chain System changes include: supply chain software enhancements and configuration for meter procurement process; support for RFID additional software enhancements related to tracking meter volume and deployment schedule; and integration with other systems in the meter deployment workflow. The Meter Supply Chain System proposed in our 2006 GRC will also need to be reconfigured to enable the "embedded" modules to support the procurement processes for the AMI meter. Additionally, these enabled modules will require integration with several other procurement management-related systems, including vendor management, asset management, and financial management systems to create a highly automated system to support the end-to-end meter supply chain business process from meter vendor to field installation. Overall we estimate that the system reconfiguration and the related system changes will cost $12.5 million over the 2006 to 2021 timeframe.

[25] *See* SCE's 2006 GRC Application (A.04-012-014) submitted on December 21, 2004.

f) Records (I-6)

We expect that new applications will be developed and existing applications will be enhanced to support automating the meter change workflow and meter read conversion processes to accommodate the meter change volumes. Additional applications will be developed and enhanced in Scenario 4, including Usage Calculation, Service Billing and SCE.com. The costs associated with developing the system requirements and database schema are captured in this cost code.

Application development and enhancement is primarily performed by contractor resources. We estimate the cost for these activities at $0.53 million over the 2006 to 2007 timeframe.

g) Update Work Management Interface to Process Additional Meter Changes (I-7)

Another critical element of system enhancement and development is designing interfaces between the various systems and verifying that they are working as designed to ensure that information flows appropriately. We will engage contractor resources to handle these activities during 2006. We estimate the cost for these activities at approximately $29,800.

h) Maintain Existing Hardware/Software that Translate Meter Reads into Bills (I-8)

Our Billing and IT organizations will work jointly to determine system requirements needed to gather usage data and translate it into billing data. Once system requirements are identified, these organizations will assist in the testing of new software. We estimate $1.3 million in project management and business analyst support labor costs for these activities over 2006.

As detailed in the description for cost code I-7, we will engage contractor resources to handle interface design and verification activities during 2006. For cost code I-8, we expect to use contractor resources as well and estimate the cost for these activities at $177,400.

i) Process Bill Determinant Data (I-9)

In Scenario 4, the introduction of demand response rates will significantly increase the amount of usage data that is collected and processed. Instead of having one read and one time stamp per month for each account, we will have 730 reads and 730 time stamps per month. With this volume of data, we expect there will be additional usage validation failures. As such, we will need additional customer service representatives to manually process the accounts that the system is unable to process. Our personnel estimates include costs for 41.7 FTEs in 2008, tapering off to 12.3 FTEs for the 2014 to 2021 timeframe. Given the significant increase in personnel, our labor cost estimate is $16.8 million and non-labor is expected to be $1.1 million.

In terms of our IT systems, we will also need to dedicate resources to defining additional rules that will determine whether data is processed by the system or whether it needs to be reviewed manually by a customer service representative. We will engage contractor resources to handle these activities during the 2006 to 2007 timeframe. We estimate the cost for these activities will be $505,000.

j) Contract Administration and Database Management (I-10)

We do not forecast any incremental contract administration costs for this cost code. The incremental costs for infrastructure database management are included in cost code I-16.

k) Exception Processing (I-11)

As meter failures occur, we expect that these accounts will fail billing system validations and will require manual intervention. This manual processing involves determining how a bill will be processed when a meter failure occurs during the middle of a billing period. Depending upon the nature of the meter failure, judgment is often required to estimate usage. Of the total meter failures, we estimate that 50 percent will require manual processing. Thus, additional customer service representatives will be needed to manually process these accounts so that customers continue to receive timely and accurate bills. Our estimates for this cost code include costs for 12.5 FTEs in 2006, peaking at 22.3 FTEs in 2008, and tapering off to 2.0 FTEs by 2011. The estimated cost of $6.5 million over the 2006 to 2021 timeframe for this cost code is based on processing five accounts per hour for the first three years. As employees become familiar with how to handle these accounts, we expect their productivity to increase to 10 accounts per hour, beginning in 2009.

In terms of our IT systems, we will need to dedicate personnel to define and develop the process to handle exceptions. We will engage contractor resources to handle these activities during 2006. The estimated cost of these activities is $97,700.

l) License/O&M Software Fees (I-12)

Software licenses are required for the RFID technology solution incorporated in the meter supply chain management system. The estimates in this cost code include an initial software license fee and aggregate ongoing license fees of $3.9 million during 2006 to 2021.

m) Ongoing Data Storage/Handling (I-13)

The incremental costs associated with ongoing data storage/handling have been captured in the estimates for cost code I-16.

n) Ongoing IT Systems (I-14)

As previously discussed throughout this section, full AMI deployment will require us to develop new applications and enhance existing applications to facilitate the meter supply chain management, meter change workflow, and meter read conversion processes. The ongoing O&M costs for these applications include applications support, security administration, database administration support, and maintenance and enhancement activities associated with the portfolio of applications that have been developed or enhanced to support AMI. The costs in this category are comprised of both contract and SCE labor. We estimate the costs for the activities in this cost code at $13.5 million during the 2006 to 2021 timeframe.

o) Operating Costs (I-15)

The fully operational communications infrastructure will contain 168,000 commercial meters with radios, 9,600 collectors, 96 packet routers, and 181 MCC take-out points. As the infrastructure develops during the deployment period and beyond, we will need to phase-in additional personnel to handle the on-going management of this network. By 2010, we estimate that we will need 85 incremental personnel. We will utilize a mixture of full-time personnel and contractor resources to meet this need. Based upon our current experience with managing the network, we assume that we will need 20 engineers and IT specialists for every 40,000 radios. We forecast the incremental SCE labor costs from 2006 to 2021 at $42.3 million and the incremental contractor costs from 2006 to 2021 at $12.4 million.

p) Server Replacements (I-16)

We assume that the computing systems hardware identified in cost code I-2 will be refreshed on a five-year technology refresh cycle. For purposes of this business case analysis, a hardware refresh would occur in 2011 and again in 2016. We did not include a final refresh in 2021 based on our assumption that the entire AMI system will be obsolete and need to be renewed with new technology and supporting infrastructure. The design and installation of the new hardware will be handled by contractor and incremental SCE resources, the costs of which are included in this cost code. Incremental SCE labor costs for database management are also included in this cost code. We estimate the costs for refreshing the computing systems and associated labor at $47.1 million.

4. Customer Service Systems

This section describes the Customer Services Systems related cost codes utilized in assigning costs for the full AMI deployment scenario. Call Center, Meter Order Processing, Customer Communications and a portion of Billing-related costs are included in this cost category.[26] This section will not include meter reading and field services costs, because these functions are essential to the Meter System Installation and Maintenance costs as previously discussed in this volume.

a) Start-up and Design

Appendix A of the July 21, 2004 Ruling did not identify any "start-up and design" related costs in the Customer Service Systems categories. We have, however identified some billing related "start-up" costs. This includes the need for approximately 1.65 FTEs in 2006, going up to 3.16 FTEs in 2008 as the full deployment scenario reaches its peak installation phase. These billing related start-up costs are associated with the specification of security systems, the development of data retrieval strategies, network planning, and the meter RFP proposal specifications. These costs are included under cost codes C-1, C-5, I-1, and M-2.

b) Customer Records, Billing and Collections Work Associated with Roll-out of the Meter Change Process (CU-1)

The majority of costs in this cost code relate to the processing of meter orders. Meter order processing costs are based entirely on the volume of anticipated meter change orders in excess of those that would normally be processed in the Business As Usual case (see Appendix G). These costs are driven by routine change orders that fail to process initially in the automated meter processing system and must be manually

[26] The majority of our billing system installation and operating costs are included in the Information Technology section because cost codes I-9 and I-11 better described the billing related functions of "validating and creating billing determinate data" and "Exception Processing."

reviewed as an exception and reprocessed. This is a labor intensive process that is estimated to cost $14.8 million through 2021.

We anticipate a need for additional Billing organization personnel to support the revenue protection activities. As discussed in cost code MS-12, we expect our installers to discover potential energy theft situations that need to be investigated during the deployment process. Our Billing Organization will contribute to the resolution of these potential energy theft situations by performing analysis, interfacing with the field personnel, potentially rebilling customers' accounts, and corresponding with customers. We estimate approximately $1.8 million in labor costs for these activities over the 2006 to 2021 timeframe.

c) Increased Call Center Activity During Installation Phase of the Full Deployment Operational Case (CU-2)

Initially, we expect a relatively small volume of calls to result from mass market media messages introducing the meter change to the affected customers. This estimate is based on prior experience with similar communications campaigns. We expect a slightly larger volume of calls to occur as a result of the initial "meter change letter" that will be sent to all affected customers during the installation phase. We estimate that three percent of customers will call if only a letter or bill insert is sent and four percent if door hangers are left after service is complete.

The introduction of TDR schedules to facilitate customers' demand response will lead to additional call volume. We anticipate rolling out TDR schedules in the following manner. First, we will send customers information notifying them that their rate will be changed to a CPP rate schedule. We estimate that five percent of customers will call when notified that their rate is being changed. The five percent estimate is based on our experience with other communications in which rate modifications are included. Second, there will be customer calls related to opting out of the new rate. Our estimates assume 27 percent of customers call about opting out and 70 percent of those that call will actually choose to opt-out. Overall, for this cost code we are expecting an increase of 850,000 calls per year during the installation phase of the project. This results in a total Call Center cost increase of $14.4 million over our business as usual costs.

Because we expect some small percentage of these calls to the Call Center will result in additional meter order processing, $183,000 in total cost has been added to this cost code to provide for these changes.

d) Modification and Customer Support Costs for AMI Integration to the Outage Management Systems (CU-3)

SCE's Outage Management System (OMS) is expected to function as it does today, entirely independent of the new AMI infrastructure. Other than some very minor IT costs ($169,000) we have not identified any other incremental implementation costs related to OMS for this cost code.

e) Process Meter Changes for New Meter Installation and DA Accounts (CU-4)

Our Meter Services Organization (MSO) costs for activities related to this cost code are expected to be $14.3 million. These activities include engineering and sample testing of meters prior to installation. The bulk of MSO metering installation work is classified as Meter System Installation costs in cost code MS-5. The Billing Organization has allocated approximately $2.6 million to the CU-4 cost code through 2010 for exception processing work directly related to meter changes during the installation phase. We did not forecast any billing costs in this cost code after the installations are completed in 2010.

f) Additional Rate Analysis Due to Multiple TOU Options (CU-5)

Even if no new rates were introduced under this scenario, we would expect an increase in on-going rate analysis work in our Billing Organization due to an increase in the number of customer inquiries spurred by the large number of meter changes taking place. As CPP and RTP rates are introduced in Scenario 4, we expect to experience an additional increase in the number of customer requests for rate analysis. These requests are expected to affect not only our Billing Organization, but our Major Customer Division (MCD) as well. MCD provides coordination between account representatives and major customers for rate analysis opt-out and contract revisions. Customers who are deciding whether to opt out may want to request a rate analysis to determine if the rate assigned to them is the best rate for them. Customers who decide to opt-out of the rate may further request rate analysis to determine a more appropriate rate. The total increased cost for both Billing and MCD associated with these activities is expected to be $2.2 million in cost code CU-5.

g) Alternative Safety Measures and Reduced Customer Safety (CU-6 and CU-7)

Cost codes (CU-6 and CU-7) have to do with reduced customer safety and alternative safety measures, "because meter readers are no longer available." Although we recognize there is some foregone operational benefit in no longer having meter readers periodically inspecting our metering installations, we have no records relating to the frequency or value of our meter readers finding unsafe, or faulty electrical service equipment. Thus, we have not included any cost estimate in these two cost codes.

h) Customer Education of Rate Change (CU-8)

In Scenario 4, beginning in 2007, the Call Center expects to receive customer calls related to their first series of bills after changing rates. We projected that our customers would go through a learning curve period in which a declining percentage of customers would call after each bill is received after switching to the new rate. For Scenario 4, these rate-related calls are expected to increase call volume by 100,000 to 150,000 calls per year at an added cost in cost code CU-8 of $2.5 million. Web-based rate communication costs are estimated at $0.4 million in this cost code. We will also incur some relatively minor costs of $0.1 million in cost category CU-8 related to developing materials for our customer account representatives and major customers.

i) Customer Support for Internet Based Usage Data Communications (CU-9)

We expect to receive approximately 10,000 additional calls annually from customers with questions related to their first review of usage data presented on SCE.com. As previously discussed, we projected that our customers would go through a learning curve period in which a declining percentage of customers would call after each session on SCE.com to review usage data. The total costs over the analysis period associated with these additional calls, which are charged to cost category CU-9, are estimated to be $212,000.

We also expect to incur costs related to the development of market research surveys to learn about customers' wants and needs so that the information learned can be applied to enhance the website. Costs will also be incurred related to assisting major customers in learning how to use the website and how to access their usage data. This will also provide support to the Customer Communications Organization by handling customer telephone calls regarding complex website related questions. The costs for these activities, which will be charged to cost code CU-9, are estimated to be $7.3 million. These web-based costs include the total cost of replacing the existing systems and we have identified over $4 million in offsetting benefits, which are included in benefit codes CB-8 and MB-1.

The increased use of internet usage data is also expected to result in additional Billing Organization costs of approximately $0.8 million.

j) Outbound Communications (Mass Media Costs, Print, Radio, TV) (CU-10)

The mass media Customer Communications programs related to this scenario are expected to cost a total of approximately $149.7 million. Another $64 million in Customer Communications and Marketing costs related to this scenario are, by definition included in cost code M-14 ("Customer Acquisition and marketing costs for new tariffs"). These will be described below in the "Management and Miscellaneous Other" cost category.

5. Management and Miscellaneous Other Costs

These cost codes include general overhead costs that span across two or more functional cost categories, such as project management and the administration of job skills training.

a) Buyout of Existing Itron Contract for Automatic Meter Reading (M-1)

In 1999 and 2000, SCE installed and implemented a large AMR program. This program included 350,000 meters equipped with electronic encoder/receiver/transmitters (ERTs), which provide the means to read meters automatically from a van being driven past each meter location. The task of driving by each meter site on a monthly basis and collecting the metered data was outsourced to Itron under the terms of a 10-year contract, which will expire in 2011. For purposes of this AMI program analysis, the original $11 million capital cost of the van-based AMR program and the entire cost of the 11-year contract are considered to be "sunk costs." This means none of this investment, including the contractual commitment, can be recovered other than by having Itron serve out the terms of the contract. Because we are already reading these meters automatically, we expect no incremental operational benefit will be derived from including these existing AMR meters in the AMI program. Because Itron actually owns the ERT component of these AMR meters, a significant part of the annual contract cost goes toward Itron's own capital recovery and it is unlikely that Itron would forego future remuneration under this contract.

In Scenario 4, we would attempt to recover as much operational benefit as possible from the existing contract by leaving the AMR meters in place as long as possible and having Itron continue to read the ERT meters until the final phase of the AMI installations. Because we assume SCE will need to pay any remaining contractual obligation to Itron in order to complete the contractual commitment, no change in cost has been assumed in this analysis for reaching such a settlement in the final year or two of the contract.

b) Meter RFP Process and Contract Finalization and Administration (M-2)

The development and review phases of the RFP process are expected to involve the participation of the major SCE departments participating in the project. As a major participant in this process, the Billing Organization has included a portion of an FTE and about $63,000 to this cost code. All other participating organizations have included the costs associated with this process in the direct overhead costs associated with their respective start-up and installation cost estimates. The PAMM Organization costs related to the preparation and review of the RFP were included in cost code MS-10.

c) Customers' Access to Usage Information Through Communications Medium (M-3)

We expect to incur approximately $1.2 million in exception billing costs attributable to the increased availability of usage information to the customer.

d) Employee Communication and Change Management (M-4)

We have included approximately $308,000 through 2021 for the Billing Organization for this cost code. This estimate is for expected costs related to preparing and communicating project status information to Billing Organization employees and keeping them informed and up-to-date on the implementation of AMI and its related systems. We estimated $104,000 in additional cost over the duration of the analysis period for web-related costs associated with general employee communications.

e) Employee Training (M-5 and M-10)

The M-5 cost code includes “systems and rate structures training.” Training of Call Center personnel, meter readers, and meter test technicians is included in cost code M-10. There are two elements to employee training costs–the trainee related cost of non-productive (seat) time spent in the classroom and the cost of the trainer and training staff, including training materials, classroom preparation, etc. All “trainee” related costs are included in the operational costs of each individual operating organization. Most of the training will be provided by our Job Skills Training Organization (JST), whose costs are included here and under cost codes M-10 and MS-11. The Billing Organization and the Call Centers supplement the JST training with their in-department training as needed. Meter System installation training was included in the MS-11 cost code as discussed previously in this volume. The M-5 cost code includes “systems and rate structures training.” Training of Call Center personnel, meter readers, and meter test technicians is included in cost code M-10.

In Scenario 4, we estimate there will be cost increases to develop and deliver training for all CSBU employees. CSBU employees include: Billing, Call Center, Credit and Payment Services, Field Services & Meter Reading (FSMRO), MSO, Major Customer Division (contact personnel and customers), and Rural Office personnel. Training will consist of communications, overviews, rates, processes, policies, and procedures related to AMI. Additional new-hire and enhancement training will be required for Billing, MSO (Meter Order Process), and FSMRO in support of AMI. Table 3-12 summarizes the estimated training costs related to implementation of the full deployment case.

Table 3-12 Training Costs by Cost Code (Full Deployment Costs in 2004 PV $)	
Cost Code	**Costs through 2021**
M-5 (Systems and Rate Structures)	$1.2 million
M-10 (Call Center, Meter Readers, Meter Techs.)	$2.1 million
MS-11 (Meter Installers, Handlers, Shippers)	$6.7 million
Total	$10 million

f) Meter Reader Reroute Administration (M-6)

The cost of recycling and rerouting meter reading for the 10 percent of meters that will not be read remotely through the AMI network has been accounted for in cost code MS-1, as discussed previously in this volume. These costs are being absorbed as a portion of the cost of the one additional supervising FSR assigned to each of the 24 districts to supervise the AMI meter system installation process.

g) Overall Project Management Costs (M-7)

Implementation of AMI will require the formation of a centralized Program Management Organization to be made up of management representatives from each of the key operational areas. The Program Management Organization will be responsible for the overall coordination required to assure that all program goals and objectives are met in a timely and cost effective manner. Throughout the installation phase of the project, the Program Management Organization will consist of eight middle management and two staff/analytical support personnel. In addition we anticipate the need for 18 external support (contract) personnel in the initial year, dropping down to 12 in 2007 through 2010. The estimated cost of the centralized Program Management Organization will be approximately $5.8 million initially in 2006, dropping down to $4.6 million by 2010 and leveling off at $450,000 in 2011 through the end of the project in 2021.

Program Management costs are expected to total approximately $19.8 million over the duration of the project.

In addition, each of the operating organizations has included the cost of their internal project management responsibilities in this cost code for a total of $15 million over the duration of the project. In total, we expect overall program and project management costs to be approximately $34.8 million through 2021.

h) Recruiting of Incremental Workers (M-8)

We expect that implementation of full AMI deployment will severely affect the recruiting and hiring process within the three most heavily impacted organizations, Meter Reading, Call Center, and Billing. For the most part, the incremental cost of recruiting the anticipated increase in personnel has been included in the cost estimates for each organization separately in their respective cost codes. Because of the initial start-up impacts on FSMRO personnel, that organization has included $225,000 in this cost code.

i) Supervision of Contracts and Technology Personnel Assigned to Hardware and Systems Development (M-9)

These costs are reflected within the individual operational areas. Accordingly, we did not forecast any additional costs under this cost code.

j) Training for Other Traditional Classifications (M-10)

As described above, the training costs included in this cost code are expected to be $2.1 million. This includes $.82 million in additional cost for specialized training in the Call Center to enable them to respond to the large anticipated call volume brought about by the opt-out provisions of the CPP default rate.

k) Work Management Tools (M-11)

Our Business As Usual operations, discussed in Appendix G, include the cost of providing our management with the most up-to-date work management tools available. Thus, no incremental cost has been included for new or additional work management tools in this cost code for any of the AMI deployment scenarios.

l) Capital Financing Costs (M-12)

Capital and financing costs (M-12) are included in the NPV calculations at SCE's long-term weighted average cost of capital.

m) Cost of Increased Load During Mid-peak and Off-peak Periods (M-13)

There is no change in the cost associated with mid- and off-peak loads (M-13) under this scenario.

n) Customer Acquisition and Marketing Costs for New Tariffs (M-14)

Incremental customer acquisition and marketing costs in this cost code, combined with the marketing costs described in cost code CU-10 above, make up the total customer communications program. This cost code includes $64 million of the $214 million to be spent on customer acquisition and customer education programs that will be necessary to secure 80 percent of the AMI metered customers on a CPP rate, and keep them there for the duration of the analysis period.

o) Risk Contingencies (M-15)

The Energy Supply and Marketing Organization has included $2.3 million in added "risk management" cost for their Load Forecasting group to support the analysis and more complex modeling that will result from the availability of real-time data after AMI implementation. The group will query a 90 percent plus sample of real-time, prior-day load data from end-use customers on a daily basis. The data will require "cleaning" and comparison to prior month's settlement data to estimate the 100 percent bundled load per hour for the previous day. Additionally, to support trading, the Load Forecasting group will analyze the price versus usage patterns by hour and by month to account for how customers will respond to post AMI conditions (compared to current, non-AMI conditions) and use this analysis to adjust the forecast one to five days in the future.

Long-term forecasting will also be impacted by the availability of hourly/monthly sales data. Approximately $3.3 million in benefits expected to result from this process are discussed under benefit code SB-9.

Overall program contingency costs have been estimated at $64.5 million. Risk contingencies related to this scenario are discussed below.

B. Benefits

Table 3-13 summarizes the total estimated benefits we expect to result from the full deployment of AMI under Scenario 4.

Table 3-13
Summary of Benefits for Scenario 4
(2004 Pre-Tax Present Value Dollars)

Benefit Categories	Total
Systems Operations Benefits	$307,333
Customer Service Benefits	8,268
Management and Other Benefits	122,316
Demand Response Benefits	366,731
TOTAL:	$804,648

The following sections will describe only those benefit codes that were actually used in analysis of Scenario 4. Appendix H contains a discussion of all benefit codes identified in the July 21, 2004 Ruling, whether we actually included them in this analysis or not.

1. System Operations Benefits

In this section we will address the potential "system operations benefits" expected to result from full deployment of Scenario 4 to approximately 4.8 million SCE customers. Appendix A of the July 21, 2004 Ruling identified 13 such potential benefits that may occur. In our review of these potential benefits for Scenario 4, we have been able to quantify $307.3 million in savings, coming from only four of the 13 benefit code areas. We also expect some net benefit from one benefit code (SB-7), which we are not able to quantify at this time. Eight of the potential areas of benefit identified in the July 21, 2004 Ruling are either already being experienced by SCE or have associated costs that more than offset the anticipated savings.

a) Reduction in Meter Readers, Management and Support (SB-1)

This is the single largest area of operational benefits expected to accrue from AMI. We currently employ approximately 570 meter readers and 80 management and support personnel, 80 percent of which would be eliminated with full deployment of AMI. Full deployment of AMI will result in our ability to automatically read 90 percent of all our meters. The remaining 10 percent, or approximately 470,000 meters, will continue to be read monthly by approximately 109 meter readers.[27] In addition, we expect to eliminate 16 of the existing meter reader supervisor positions with full deployment of AMI.[28]

The reduction of 80 percent of our current meter reading organization would result in a total savings of $271 million (expressed in 2004 present value dollars) over the duration of the analysis period. With our current attrition rate of 35 to 40 percent annually, the reduction of meter reading personnel is expected to take place through normal attrition during the latter phases of AMI deployment. Attrition is expected to ramp-up beginning with the actual activation of the AMI communications system (approximately 18 months after AMI installations begin) and continue throughout the deployment years. Severance of 32 supervisory personnel will result in a one-time cost of $3 million in 2010 ($1.9 million present value dollars). This severance cost is included

[27] The remaining 10 percent of the meters with which we are unable to communicate are scattered throughout the SCE territory and generally not adjacent to one another, thus making manual meter reading less efficient than it is today. Our assumption is that it will take 20 percent of the existing number of meter readers to read the last 10 percent of meters.

[28] These 16 supervisory positions are incremental based on the number of supervisory personnel required today, without AMI. The actual Reduction in Force (RIF) will require severance of 32 supervisors due to the temporary build-up of personnel to deploy AMI.

in cost code MS-1. Additional savings will result from the decommissioning of 80 percent of our hand-held meter reading devices. This savings is reflected in benefit code MB-1.

b) Field Service Savings (SB-2)

SCE currently completes nearly half of its "turn-off" and "turn-on" meter orders without having to actually turn the meter on or off. This situation occurs when a "turn-on" order can be matched to a "turn-off" order for the same location, on or about the same day. Such orders can be completed merely by taking a meter read, which currently requires a visit to the site at an average cost of approximately $15 per order. Virtually all of these special meter reads for matched on/off meter orders could be eliminated and replaced with the daily AMI meter read. This benefit would result in savings of approximately $29 million over the duration of the analysis period (*i.e.,* through 2021).

c) Phone Center Savings from Billing Inquiry Reductions Due to More Accurate Billing (SB-4)

Billing inquiries today are received for several reasons, only one of which is an inaccurate meter read. Based on a study using 2003 data, 22,791 calls to the Call Center were a result of meter reading errors. We used this number as a percentage of all calls to determine the percent of calls in subsequent years that would be projected as meter read error calls. For purposes of this preliminary analysis, we assume that 100% of these calls will be avoided with the full deployment of AMI.

Table 3-14 shows the number of avoided calls that may result from the complete elimination of meter reading errors. Using 3,376 as the average number of Billing Inquiry calls answered per FTE in the Billing Inquiry specialty support group in 2003, we are estimating a levelized reduction of seven FTEs by 2010, for a total benefit of $3.4 million through 2021.

Table 3-14 Reduced Phone Calls – Full Deployment					
Year	2007	2008	2009	2010	2011
Reduced Calls	8,445	14,089	19,753	23,626	23,626

Our Energy Supply and Marketing Organization has estimated $3.3 million in reduced resource acquisition costs in benefit code SB-9. This is the result of improved long- and short-term forecasting attributable to improved modeling and analytical techniques using AMI data.

2. Customer Service Benefits

The July 21, 2004 Ruling identified 13 Customer Service Benefits. This section will address our review and conclusions related to only those potential Customer Service Benefits that were actually used in our analysis. Appendix H discusses all 13 potential customer service benefit codes, whether we used them or not.

a) Improves Billing Accuracy – Provides Solution for Inaccessible/Difficult to Access Sites – Eliminates "Lock-Outs" (CB-1)

Inaccessible and/or locked meter sites are the primary reason for estimated and/or untimely bills. Automated retrieval of meter reads eliminates these meter access problems and reduces the need to estimate monthly meter reads. This, in turn, eliminates the need for many "pick-up" reads and billing inquiry investigations. We have estimated the savings related to this benefit to be approximately $5.4 million over the duration of the analysis period.

Additional related benefits in the Call Center have been identified under benefit code SB-4.

We have estimated $2.9 million in operational cost offsets to accommodate those customers who are already on demand response rates or who otherwise use the web-based programs for energy management information.

3. Management and Other Benefits

Only two of the 10 potential "Management and Other" benefit codes identified in the Ruling were actually used in SCE's analysis of Scenario 4. The following sections describe our review of each of the potential "Management and Other" benefit codes. The benefit codes that were not used are discussed in Appendix H.

a) Reduced Equipment and Equipment Maintenance Costs (Software Maintenance and System Support, Handheld Reading Devices, Uniforms, *etc*.) (MB-1)

In the full deployment scenario, we expect to reduce costs by approximately $2.9 million over the duration of the analysis period by decommissioning 80 percent of our hand-held meter reading devices. Typically these electronic devices would be replaced every five years. This is a cost that would no longer be incurred under full AMI deployment. We have also recognized $1.2 million in equipment replacement benefits resulting from upgrading the web-based systems and equipment.

b) Reduced Miscellaneous Support Expenses (Including Office Equipment and Supplies) (MB-2)

These savings have been included in the SB-1 benefit.

c) Reduced Meter Inventories/Inventory Management Expenses due to Expanded Uniformity (MB-4)

Electronic meters have a broader range of functionality than do their electromagnetic predecessors. This enables us to carry fewer meter types in inventory than was formerly the case. This benefit is already being utilized given that SCE has already started replacing all large customer meters and all time-of-use meters with RTEM or interval meters. This benefit is offset in large part by the higher failure rate of electronic meters compounded by their inherently shorter useful life, both of which result in higher inventory turn-over. The AMI system will introduce higher volumes of inventories for communications equipment, and replacement parts than existed previously. For these reasons, we have not included any benefit value for reduced meter inventories.

This benefit code contains our avoided cost of purchasing approximately 72,000 conventional new and replacement meters each year for the full duration of the analysis period. As discussed in the Business As Usual case, the material cost of 72,000 new and replacement non-AMI meters each year is significantly different than the replacement cost of these same 72,000 meters each year using AMI meters.[29] For this reason, the total cost of all new and replacement AMI meters has been included in Scenario 4 in cost code MS-3. The avoided cost of not purchasing conventional meters for customer growth and routine replacements is included in this benefit code. For the full deployment scenario, this avoided cost is $118.2 million over the duration of the analysis period.

d) Summary Billing Cash Flow Benefits (Existing Customers) (MB-5)

SCE currently has approximately 418,000 individual service accounts being billed monthly on approximately 118,000 summary billing accounts (approximately 3.5 accounts per summary bill on average). Because the individual accounts are currently being read throughout the month, billing for the earlier read accounts is necessarily delayed until the last account is read, in order to bill all service accounts on the summary bill at the same time. This results in significant cash lag for these accounts. Theoretically, full deployment of AMI would allow us to synchronize the read dates for all service accounts on summary bills, virtually eliminating the current cash lag. The recent deployment of RTEM metering already provides the means to achieve a large part of this potential savings, since most of the cash lag is attributed to large customers over 200 kW.

[29] *See* Appendix G.

Full AMI deployment could result in some further savings to SCE, as most of our summary billed service accounts' meters become automated. Though there would be substantial benefit realized from rescheduling billing dates for the largest customers, there would be significant cost involved in making this change for all summary billed accounts and it is not clear at this time at what level of consumption this change would be cost effective. For this reason, we have not associated any savings with this benefit code.

e) Possible Reduction in "Idle Usage," Meter Watt Losses—At The Very Least, Quicker Resolution of Idle Usage Episodes (MB-6)

AMI meters have the ability to meter smaller loads (<25 watts) than do existing electromagnetic meters. Most electromagnetic meter discs sit "idle" when less than 20 to 25 watts are being consumed. Our review of our existing residential load survey data shows that some minimum load between 0 and 25 watts exists approximately three and a half percent of the time (*i.e.* approximately one hour per day on average). Though significant time-wise, the actual energy consumed during this unmetered hour is less than 0.004% of total metered kWh on average. For an average residential customer, this would equal approximately 25 watt-hours per month. On an annual basis, we estimate that under full deployment, all AMI meters would meter a total of approximately 1.4 million kWh per year (approximately $60,000 in energy costs) more than their electromagnetic predecessors. More accurate measurement of this energy would not result in any cost savings, but merely in a reallocation of these costs to those customers responsible for this currently unmetered load. Because the value of this unmetered load is so small, we have not included any savings attributable to this benefit in any of the scenarios.

The "watts lost" rating of an electronic meter is typically greater than that of the single phase electro-mechanical meter it would be replacing. We estimate the average AMI meter would be rated at approximately one watt higher than their single phase electro-mechanical counterparts. For Scenario 4, this would add four megawatts of load 24 hours a day, 365 days per year. This would add over 35 million kWh per year in energy consumption.

An "idle usage episode" occurs when a routine meter reading results in some consumption being recorded for an account that is supposed to be turned-off (or "idle"). This situation occurs when a customer moves into a home or business and fails to notify SCE that they have turned the service on and have begun to use electricity. Typically, it can take 30 to 60 days to detect and investigate this occurrence and finally issue a bill to resolve the problem. Theoretically, with AMI metering, we expect such idle meter episodes can be detected 15 days sooner on average, resulting in a higher probability of obtaining compensation for the unauthorized use, and a reduction in revenue lag. In reality, most idle usage episodes resolve themselves within a matter of days of their occurrence and, as a practical matter, because of the service disconnect costs, exception bill processing, and other related costs of idle usage resolution, we do not attempt to notify the customer of a pending disconnect until a threshold of 400 aggregated kWh is exceeded. Identifying idle usage episodes in a timelier manner with AMI meters does little to remove these more practical processing cost considerations and any actual savings would be insignificant.

f) <u>May Facilitate Ability to Obtain GPS Reads During Meter Deployment—Improving Franchise and Utility Tax Processes (MB-8)</u>

GPS reads will be recorded for all meter locations during the installation phase of AMI deployment. This will be done to mark the actual location of the meter site, because it may be several years before we will ever have to revisit the meter. The GPS read will reduce the odds of physically "losing" the meter as customers add walls and fences, making it difficult to keep track of the meter and its access route. It is conceivable that these GPS reads can be incorporated into the Franchise Payment and

Utility User Tax processes, in order to assure more accurate processing of these fees. Because there would be offsetting costs to develop the systems interface to facilitate the use of GPS readings, a much more intense review of costs and benefits would have to be undertaken to determine the economic feasibility of this potential benefit.

g) Potential for Tax Savings from Federal Investment Tax Credits (MB-10)

We are not aware of any Federal Investment Tax Credits that would apply to AMI deployment under current law, and no such benefit has been included in any of the deployment scenarios.

C. Demand Response

This scenario assumes that 80 percent of eligible customers are defaulted to CPP-F rates (residential) or CPP-V rates (commercial <200 kW) and that those customers stay on those rates for the full duration of the business case. For purposes of our analysis, we assumed that customers opting-out of the default rate would either switch back to their tiered rate or choose a TOU rate in equal proportions. The demand response benefits for Scenario 4 are summarized below in Table 3-15. These benefits were calculated using the assumptions and methodology discussed in Appendix C.

Table 3-15 Scenario 4 - Demand Response Benefits Summary				
	No. of Meters (Customers) Year 2021	**Percent of Eligible Meters**	**Present Value Rulings Assumptions ($ millions)**	**Present Value SCE Assumptions ($ millions)**
Meters Eligible for TDRs	4,835,650			
Customers Enrolled on CPP-F/V	3,868,520	80		
Customers Enrolled on TOU	483,565	10		
Customers Enrolled on Current	483,565	10		
Total DR-1 Benefits			$326	
Total DR-2 Benefits			$41	
Total DR Benefits			$367	$213

We have not adjusted the above demand response benefits for Value of Service Loss to customers due to participation in on the CPP and TOU rates. Our methodology and analysis of Value of Service Loss by scenario is presented in Appendix J. For this scenario, the Value of Service Loss is approximately $161.2 million (2004 present value dollars), reducing the total demand response benefit from $367 to $205.9 million.

D. Uncertainty and Risk Analysis

1. Operational Cost Uncertainty and Risk Analysis

We performed an operational cost and benefit risk assessment of this full deployment scenario based on the specific cost and benefit data discussed in the sections above. For analytical purposes, this operational cost risk assessment focuses on the 47 most significant cost codes that comprised over 85 percent of the overall cost. Once the appropriate cost codes were identified, we developed the most likely high and most likely low ranges for each of the cost codes. We then applied a Monte Carlo statistical approach to create a probabilistic range around our estimate.

a) Significant Cost Areas

For this full deployment scenario, the total present value cost estimate (prior to adding contingencies) for full AMI deployment is $1.234 billion. In the discussion that follows, we will focus on five of the significant cost areas which represent over 60 percent of the total cost for this scenario.

(1) Cost Code MS-3 – Meter Purchasing

The most significant cost code (MS-3) in this full deployment scenario is estimated at over $400 million and involves the cost of meter purchases and the purchase of meter-related communications equipment. We estimated a range for this cost code to be plus 20 percent and minus 15 percent. The high end of this range is based on our historical experience with price differences that occur between an RFI and the ultimate final contract. We find that vendor price increases of as much 20 percent are due to better understanding of scope, warranty requirements, and contract terms and conditions. We based our estimate on vendor quotes we received in the RFI. The range also reflects the uncertainty of meter failure. The low range is based on the fact that current meter technology is aging, and potential vendors have informally indicated that lower prices are possible for high-volume orders.

(2) Billing

Under this full deployment scenario our Billing Organization estimate may vary by plus 20 percent to minus 15 percent depending on the number of exceptions processed.

(3) Meter and Field Communication

The meter and field communication installation costs may vary by as much as plus 15 percent to minus 20 percent based on installation productivity.

(4) Information Technology Computing Systems

Our information technology computing systems lifecycle costs have a range of plus or minus 40 percent due to the uncertainty of the data processing and storage required.

(5) Software Development

Our software development costs ranged plus 40 percent to minus 50 percent based on the uncertainty of the final design.

b) Monte Carlo Sensitivity Analysis Results

Using the cost ranges developed for the 47 most significant cost categories, the application of the Monte Carlo statistical analysis of costs resulted in a range of $1.195 billion to $1.343 billion around the estimated cost of $1.234 billion for this scenario. The statistical analysis indicates that our cost estimate has about a 13 percent confidence level. This means that the project has an 87 percent chance of overrunning. A 90 percent confidence level is reasonable for this type of project and the results of this analysis suggest that we should include contingency for this project.

c) Contingency

We determined that contingency should be applied to the start-up and installation activities. We also believe that a 90 percent confidence level is reasonable for this type of project. Based on the analysis results, we applied a contingency of $64.5 million across the start-up and installation phases in order to achieve this 90 percent confidence level.

2. Operational Benefit Uncertainty and Risk Analysis

The primary operational benefits of Scenario 4 relate to the reduction in meter readers and result in aggregate operational savings of $271 million. We do not expect any variation because the forecast reduction is solely a function of the AMI system communication coverage that is designed to reach 90 percent of the meters. The other identified operational savings were less than the threshold we used for analytical purposes. As a result, we did not include any operational savings in the statistical analysis.

3. Demand Response Risk Analysis

We believe that Scenario 4 demand response results are implausible for a number of reasons. First, we believe that it is unlikely that CPP rates would be imposed on a quasi-voluntary (opt-out) basis on the mass-market without first testing customer acceptance of TOU rates on an opt-out enrollment basis.

Next, we believe that if default enrollment of CPP was implemented, it is highly unlikely that 80 percent of customers would adopt the CPP rate over the entire 16-year study period. The SPP found that four to six percent of customers chose to drop the CPP-F rate after the first year of the experiment despite an offering of incentive payments to continue participation in the program in 2004; and these were customers who volunteered (or opted-in) in the first place. Moreover, a shadow-bill analysis of SPP CPP-F customers found that 26.3 percent actually had higher bills than they would have if they had stayed on their otherwise applicable rate. Over time, customers who experience higher bills will likely opt out to a more favorable rate.

Another key, but unlikely assumption is that all 80 percent of customers on CPP-F and CPP-V rates would respond over the 16-year period at the same level as customers in the SPP experiment. As noted above, the SPP experiment offered customers a $175 incentive for their participation in 2003. These customers were opt-in (affirmative enrollment) rather than default enrollments. Even though we include significant expenses for customer education and awareness, as well as notification of CPP events, it is unlikely that the entire population that defaulted on to the rate on average would be as informed and as responsive as SPP customers. Previously, we described concerns and uncertainties associated with whether AB1-X would preclude a default implementation of CPP.[30]

E. Net Present Value Analysis

Table 3-16 summarizes the overall pre-tax costs and benefits of Scenario 4. Also shown is the after-tax NPV for this scenario on a cash flow basis, and the present value of the revenue requirement over the 16-year analysis period.

Table 3-16
Summary of Cost/Benefit Analysis for Scenario 4 ($Millions) Using the July 21, 2004 Ruling's Assumptions for Avoided Resource Value

Costs	Benefits	Pre-tax Present Value	After-Tax NPV	Rev. Req. Present Value
($1,298.4)	$804.6	($493.8)	($402.9)	($951.8)

Scenario 4 analysis results in a negative Revenue Requirement Present Value of $951.8 million and does not support the implementation of full AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the Scenario 4 analysis, plus the recovery of SCE's net investment in any removed meters, plus the rate of return and tax impacts of the AMI-related investments. If SCE's recommended assumptions for computing demand response benefits described in Appendix D were used, as shown in Table 3-16 above, the negative Revenue Requirement would be $1,105.4 million, as shown in the Table 3-17 below.

[30] *See* Volume 1, Section II.

Table 3-17
Summary of Cost/Benefit Analysis for Scenario 4 ($Millions) Using SCE's Assumptions for Avoided Resource Value

Costs	Benefits	Pre-tax Present Value	After-Tax NPV	Rev. Req. Present Value
($1,298.4)	$651	($647.4)	($494.2)	($1,105.4)

V.

BEST PARTIAL DEPLOYMENT BUSINESS CASE ANALYSIS (SCENARIO 17)

This section provides our "best case" approach to partial AMI deployment. Partial AMI deployment is best suited for the portion of our service territory where we can reasonably expect to realize the greatest demand response benefits. We believe the most populated communities of Climate Zone 4, as delineated in the Statewide Pricing Pilot (SPP) afford us the best opportunity to meet this objective. This includes Lancaster, Palmdale, Victorville, Apple Valley, and the populated areas of the Coachella Valley, including Palm Springs and the surrounding communities. The following sections describe the costs and benefits we expect will result from implementation of this scenario. These costs and benefits are described as "incremental" to our "Business As Usual" case, as presented in Appendix G. All costs and benefits have been quantified using the Ruling's assigned cost and benefit codes. We also present a discussion of the uncertainties and risk analysis for this scenario, as well as a discussion of the NPV analysis. The operational activities, processes, and procedures were discussed above. The default rate for Scenario 17 is CPP-F for residential customers, and CPP-V for C & I customers under 200 kW. Scenario 17 results are summarized in Table 3-18.

Table 3-18 Summary of Costs and Benefits for Scenario 17 (000s in 2004 Pre-tax Present Value Dollars)	
Cost	$(164,158)
Benefits	77,691
Pre-Tax PV	($86,467)
After-Tax NPV	($60,880)
NPV of Rev Req	($129,901)

A. Costs

Appendix A of the July 21, 2004 Ruling classifies AMI deployment costs into six broad cost categories: Meter System Installation and Maintenance; Communication Systems; Information Technology and Applications; Customer Services; Management and Other; and gas service costs (which are not applicable in any of SCE's scenarios). Table 3-19, below, summarizes our estimated costs for Scenario 17 in the five applicable cost categories.

Table 3-19 Summary of Costs for Scenario 17 (000s in 2004 Pre-tax Present Value Dollars)	
Cost Categories	**Total**
Metering System Infrastructure	$60,062
Communications Infrastructure	6,478
Information Technology Infrastructure	45,475
Customer Service Systems	23,122
Management and Miscellaneous Other	29,021
TOTAL:	164,158

The following subsections provide our analysis of these cost categories along with the unique cost codes within each cost category.

1. Meter System Installation and Maintenance

The cost categories of MS-1 through MS-11 correspond to the costs associated with procurement, supply chain management, testing, installation and associated support costs. The following sections describe the costs associated with each of those areas in more specific detail.

a) Meter Reader Transition Costs (MS-1)

We are assuming that our current FSRs and Meter Readers will be utilized for the "Project Temporary Installer" positions, as discussed further in cost category MS-5. This will cause a chain reaction of existing meter reading personnel, moving up to fill the vacated FSR positions. At the start of 2006, we estimate that we will have 59 vacancies in our meter reading staff caused by employee movement to other areas to support AMI deployment. We plan to fill those vacancies early in the deployment process.

When filling these positions, we have taken into account, as an incremental AMI cost, the productivity differential between a newly hired meter reader and an experienced meter reader. As such, in addition to the 59 vacancies that will be filled, we will need to hire 21 additional meter readers to compensate for the loss in productivity due to this learning curve. The total anticipated incremental cost of labor and non-labor due to the loss in productivity is $2.76 million in 2004 present value dollars.

b) Supervision of Installer Workforce (MS-2)

With the addition of new staff (discussed in the cost category descriptions for MS-1, MS-5, and MS-12), we will need to hire additional supervisors and support personnel. We forecast a need to hire one additional supervisor and one Supervising Field Service Representative for each of the three major service centers involved in the deployment. We will also add three additional FTEs to handle revenue protection activities (discussed in the cost category description for MS-12). We also expect to hire one FTE to provide support with deployment tracking and reporting. Overall, these 10 incremental FTEs are estimated to cost $0.84 million.

c) Cost of Purchasing Meters (MS-3)

Our preliminary estimate is that we will procure approximately 500,000 meters at a cost of $33.7 million over the 2006 to 2021 timeframe. We will procure four different meter types for the AMI deployment.

We will initially procure approximately 325,000 meters in order to replace the existing meters installed in the Zone 4 area. Table 3-20 shows the types of meters, quantities, and prices that will be procured for partial deployment.

Table 3-20
Meters, Quantities and Prices in Partial Deployment

Meter Type With Communication Module	Amount	Base Cost
< 20 kW residential single phase	300,942	$50
< 20 kW network	2,946	$130
< 20 kW 3-phase commercial & residential	11,241	$320
> 20 kW commercial	8,760	$700
	324,603	

As discussed above, in addition to the cost estimates in Table 3-19, we will incur additional costs for meter lock rings and adapters.

Our analysis shows that following the installation phase, we will have meters that fail after the three-year warranty period. We estimate that there will be approximately 82,000 meter failures during the 2009 to 2021 timeframe based on the projected failure rate. In those cases, we will need to procure and install new AMI meters. Table 3-21 illustrates the expected meter type and volumes associated with replacing these failed meters.

Table 3-21 Cost Table for Meter Failures—Out of Warranty Purchases for Scenario 17 (2009 Through 2021)	
Meter Type With Communication Module	**Quantity**
< 20 kW single phase	**75,963**
< 20 kW 3 phase commercial & residential network	**744**
< 20 kW commercial	**2,837**
> 20 kW commercial	**2,392**
TOTAL	**81,936**

In addition to installing AMI meters on existing meter sites, we will need to install AMI meters as we experience customer growth. We estimate approximately 82,000 new meter sets during the 2006 to 2021 timeframe due to customer growth. Table 3-22 shows the expected meter type and volumes associated with these new meter sets.

Table 3-22 Projected Meter Growth for Partial Deployment (2006 Through 2021)	
Meter Type With Communication Module	**Quantity**
< 20 kW single phase	76,368
< 20 kW network	748
< 20 kW 3-phase commercial & residential	2,853
> 20 kW commercial	2,404
TOTAL	82,373

d) Installation and Testing Equipment Costs (MS-4)

In 2006, we estimate that we will incur costs for tools, equipment, materials, supplies, uniforms, and vehicle costs associated with the new installers, meter readers, field service representatives, supervisors, and various support personnel. We also forecast additional costs will be incurred for facility costs. Current SCE service center facilities cannot house the required incremental personnel. Facilities will either be modified to handle the incremental personnel or portable facilities will be leased. In 2006, we will incur $1.82 million for installation equipment and facility costs.

In a partial AMI deployment, we would be able to take advantage of our existing equipment and would not incur any incremental costs associated with reconfiguring our meter testing equipment.

e) Installation Labor (MS-5)

(1) Residential and Small Commercial (<20 kW)

In order to meet the partial deployment schedule, we estimate that additional personnel will be needed to install approximately 325,000 meters. We project the need for 59 project temporary installers during 2006.[31] The cost for the additional personnel to perform installations is estimated to be $4.27 million in 2006.

(2) Complex Meters

To meet the partial deployment schedule, we estimate that additional personnel will be needed to install approximately 17,900 complex meters. While we rely on both full-time and contract resources in the full deployment scenario, we are solely utilizing full-time resources for the partial deployment scenario. In 2006, we will dedicate 27 Meter Technicians to these installations. These resources will also need to work overtime in order to keep up with the volume of installations. We have estimated that the overtime that will be worked is equivalent to one incremental full-time employee

[31] As in the full deployment scenario, we base this estimate on the assumption that an installer will install 25 residential meters per day or 18 commercial/industrial meters per day.

in 2006.[32] The total labor cost for all complex meter installations is estimated to be $2.22 million in 2006.

f) Meter Installation Tracking Systems (MS-6)

We expect that meter failures will occur throughout 2006. We plan to hire additional analysts to assist with tracking the meter failures. These analysts will look for trends in the failure data so that we can resolve communication or product issues with the vendor. We estimate the cost for this additional activity at approximately $0.15 million in 2006.

g) Panel Reconfiguration/Replacement (MS-7)

As described in the full deployment scenario, for the purposes of this business case analysis, we relied on our experience to develop a per meter damage cost estimate of $0.14. These costs are primarily attributable to damage caused to the customer's panel during new meter installation. Overall, the costs associated with these activities are estimated to be $0.06 million in 2006.

h) Potential Customer Claims (MS-8)

We expect to incur costs related to potential customer claims as a result of the AMI deployment. However, for purposes of this analysis, these costs have been reflected as part of the cost estimate for cost category MS-7 since we were not able to delineate the customer claim-related portion of the costs discussed above.

i) Salvage/Disposal of Removed Meters (MS-9)

As installers remove non-AMI meters, they will return these meters to the service centers. We plan to contract with a salvage company to handle removing these meters from each of our service centers. As such, we have not assumed any incremental

[32] As in the full deployment scenario, we based these estimates on the assumption that a Meter Technician can install an AMI meter in 2.5 hours on average.

costs to handle the non-AMI meters. Throughout the meter deployment period, we anticipate that there will be AMI meter failures in the field. Once the installer returns the failed AMI meter to the service center, the meters that are still under warranty will be returned to the vendor for replacement. We will require additional personnel to handle the processing of meters returned to the vendor. We estimate $0.55 million in labor costs for this activity.

j) Supply Chain Management (MS-10)

Our PAMM group is responsible for receiving and stocking meters at our central distribution facility. We expect to add more personnel to handle the increased volume of meters that will be received and processed in the central distribution facility. During the 2006 deployment period, we estimate the need for four material handlers responsible for receiving the meters from delivery trucks, storing the meters within the warehouse, and staging the meters for distribution. We also forecast the need for two warehouse clerks to maintain the integrity of the inventory by processing receipts, conducting inventories, and tracking assets. We will need a heavy-transportation driver to deliver the new AMI meters to our Meter Shop for testing and then out to the various SCE service centers for field installation. Further, we anticipate the need for additional personnel to supervise the new hires and project support personnel to provide forecasts to suppliers and to expedite and track purchases. Throughout the 2007 to 2021 time period, we will maintain some of these additional personnel to process the meter failures in the field. This processing includes sorting, packaging and shipping the meters back to the supplier as well as receiving and tracking the meters when they are returned. We will maintain two FTEs in 2007, tapering off to one FTE from 2009 to 2021. We estimate the cost for the additional personnel at $2.00 million over the 2006 to 2021 timeframe.

Currently our central distribution facility is at 95 percent capacity, maintaining a monthly average of 25,000 growth and new installation meters. Under partial AMI deployment, we expect to increase our meter inventory by 20,000 meters per month. Since the facility will need to accommodate both the new AMI meters as well as meters for the non-AMI customers, a new facility is required through first quarter of 2007 to house the meter inventory.[33] Other non-labor costs that we will incur from 2006 to 2021 are for miscellaneous equipment, packing supplies and freight costs for delivering materials to the service centers on a just-in-time basis. The estimated non-labor cost is $0.95 million over the 2006 to 2021 timeframe.

As the meters are delivered to various service centers, additional personnel are required to process the meters at the service center locations. This processing includes verifying receipt of the meter, staging for deployment, tracking of returned meters and ongoing inventory management. We estimate the need for three additional employees to handle these activities at an estimated cost of $0.78 million in 2006.

k) Training (Meter Installers, Handlers, and Shippers) (MS-11)

For employee training needs, we looked at both the trainee-related cost of non-productive (seat) time spent in the classroom, as well as the cost of the trainer and training staff. Depending upon an employee's position, they will have to take training classes, ranging from new hire meter reading classes to meter installation classes. We estimate that the seat time and travel costs for our field personnel will be $1.09 million over the 2006 to 2007 timeframe. The cost associated with developing materials for these training classes is estimated to cost $48,000 in 2006.

It is expected that most of the PAMM employees assigned to the AMI project will be new hires and will require training in all aspects of logistics including, but not limited to, safety, systems, equipment, procedures and processes. Our PAMM

[33] The start-up costs for a new facility are detailed in cost category MS-11.

Organization estimates training costs of approximately $0.57 million. As mentioned in cost code MS-10, our current central distribution facility is at 95 percent capacity and a new facility will be needed to house the meter inventory. In addition to the actual facility leasing costs, we will incur equipment and supply costs to connect the new facility with our existing communications network. We estimate that we will incur $1.37 million in costs in 2006 to make this facility operational.

l) Maintaining Existing Metering Systems (MS-12)

As meter failures occur in the field, replacement meters will need to be set. FSRs will handle this work for the residential and small commercial customers. We estimate the need to hire two additional FSRs beginning in 2006 to support the meter replacement activities.

Throughout the installation period, we expect our installers will discover potential energy theft situations that need further investigation. This assumption is based upon our experience with the Van-based AMR deployment. We plan to hire additional revenue protection investigators responsible for investigating these potential theft situations. With the increased potential to identify possible theft situations, we expect to increase our current investigator staff by two FTEs in 2006.

Today, potential theft situations are usually brought to our attention by our meter reading staff. Given that a majority of the meter reading staff will no longer be needed in most of Zone 4, we will hire one additional support person to analyze meter read data in an attempt to determine potential theft situations to be further investigated.

The labor costs for incremental FSRs, revenue protection investigators and associated support personnel are estimated at $4.79 million for the 2006 to 2021 timeframe. We will also incur $0.74 million in costs for tools, equipment, materials, supplies, uniforms and vehicle costs associated with these incremental personnel.

Additional non-labor costs are forecasted for battery replacements in the AMI meters installed on the greater than 20 kW commercial accounts. In 2016, we will begin the process of replacing these batteries and the replacement process will continue through 2021. We estimate the cost of replacement batteries will be approximately $37,000.

As the AMI communication infrastructure is deployed, we anticipate new issues to develop from the implementation of new systems and the large number of meter changes. These will impact our ability to prepare and deliver accurate customer bills in a timely manner. We estimate the need for 2.6 FTEs in 2006, 2.9 for 2007 and 2008, then decreasing to 0.9 FTEs in 2009 for project support to resolve AMI issues affecting billing. The estimated cost of this activity is $0.82 million over the 2006 to 2009 timeframe.

m) Pick-up Reads (MS-13)

When a meter fails, the failure can be caused by a registration issue or a communication issue. In either case, it will be necessary to send a meter reader to collect a pick-up read from that meter in order to maintain timely and accurate customer billing. The labor costs for this cost category are estimated to be $0.28 million over the 2006 to 2021 timeframe.[34] Non-labor costs of $0.22 million will be incurred for tools, equipment, materials, supplies, uniforms and vehicle costs associated with these meter reading activities.

n) Meter Replacement Costs (MS-14)

As we described in cost category MS-12, we will need to replace the batteries in the AMI meters that are installed on the greater than 20 kW commercial

[34] As in the full deployment scenario, our personnel estimates are based upon a pick-up read rate of 56 reads per day.

accounts. While we did estimate incremental labor costs for this replacement activity in the full deployment scenario, we are assuming that we will be able to absorb the physical battery change-out with our existing Meter Technician workforce in Scenario 17.

In addition to the labor costs described in MS-12, we will also incur equipment costs of approximately $34,000 for tools, equipment, materials, supplies, uniforms and vehicle costs associated with the additional personnel handling meter replacements.

2. Communications Infrastructure

a) Review/Specify Security System (C-1)

As we design the new communications infrastructure, it will be necessary to assess the systems needed to ensure the security of the data transmitted within the network. We plan to engage contractor resources to assist us with this assessment. The costs for this assessment will be incurred in 2006 and are estimated to be $73,000.

To ensure the accurate transmission of data from the meter to the billing systems, we will dedicate personnel to review the operational design and system requirements. We estimate the need for additional personnel for these activities in 2006 at a cost of $284,000.

b) Network Placement Site Surveys (C-2)

There are no incremental costs associated with this cost category.

c) Mapping Network Equipment on Company Facilities (C-3)

We will incur incremental labor costs during the 2006 to 2007 installation timeframe necessary to map MCC take-out point installations. Engineers will need to determine appropriate placement of the eighteen MCC take-out points within SCE's service territory. Once the MCC take-out point locations have been identified by the engineers, communication technicians will be responsible for installing the equipment.

The labor costs associated with replacing failed MCC take-out points is also included in the estimate for this cost category. Overall, we estimate the labor costs for these activities at $0.12 million.

We plan to utilize contract personnel to handle the installation of the collectors, packet routers and the antennas for the MCC take-out points, the replacement of failed equipment, as well as the battery-change out process. The contractor labor and vehicle costs associated with these activities are $0.49 million.

d) <u>Staging Facilities for WAN/LAN Equipment and Mounting Hardware (C-4)</u>

For the communications infrastructure, we will configure and test 100 percent of the network infrastructure equipment before it is deployed to the field for installation. The labor costs associated with performing these activities on 928 collectors, 10 packet routers, and eighteen MCC take-out points is estimated at $0.12 million for the 2006 to 2008 period.

In terms of maintenance costs, we currently do not have facility space that can accommodate the eight FTEs needed to maintain the communications network (these personnel costs are further described in cost category I-15). Our cost estimate includes the lease cost for a new facility which will continue over the 2006 to 2021 time period. In 2006, we will incur facility set-up charges such as costs to connect the new facility with our existing communications network. Overall, the costs associated with this facility are estimated at $0.33 million over the 2006 to 2021 timeframe.

e) <u>Review/Develop Strategies to Retrieve/Process Data From Meters (C-5)</u>

In determining the appropriate strategies to retrieve and process meter data, we needed to evaluate IT application solutions. Given the data retrieval and processing requirements associated with AMI, we need to develop new applications or, in some cases, enhance existing applications to handle these requirements. Section III of this volume details the various IT application solutions that need to be developed or enhanced in the areas of meter supply chain management, meter change workflow and meter read conversion. We have estimated approximately $0.37 million in contractor costs associated with the IT application solution design.

Our Billing Organization will continue to partner with our IT organization in determining strategies for data retrieval and processing. They will assist IT in determining the system requirements needed to prepare and deliver accurate bills in a timely manner to those customers with AMI meters. Given the additional enhanced applications, we expect project management and business analyst support labor costs associated with these activities to also increase. In addition, our Billing Organization will need to dedicate personnel to determine how its processes will be modified in order to accommodate the additional work that will be generated due to accounts failing system validations for usage-related reasons. We estimate $1.06 million in project management and business analyst support labor costs for these activities over the 2006 to 2008 timeframe.

f) Auxiliary Equipment (C-6)

Our analysis indicates that we will incur $0.42 million in auxiliary equipment costs over the 2006 to 2021 timeframe. With regard to the communications infrastructure, auxiliary equipment for the MCC take-out points and collectors is required in order to make the communications infrastructure operational. For the eighteen MCC take-out points, antennas and other equipment will need to be installed on each unit. Each of the 928 collectors will be equipped with a battery, which is estimated to have a six-year life. Beginning in 2012, we will need to begin changing the batteries in the collectors. In order to minimize installation error, contractor personnel who handle the equipment in the field will be provided with refurbished equipment instead of having them attempt to change the batteries in the field. In 2012, 100 new collectors will be purchased to begin this battery change-out process. The collectors that are removed from the network will be retrofitted with the new battery and then redeployed to the field.

For meter installations, there will be a subset of meters that require an external antenna to be installed in order to ensure that they can communicate properly with SCE's network.[35] The majority of these antenna costs will be incurred during the initial deployment period in 2006. However, the costs will continue through 2021 to reflect antenna costs associated with the loss of communication due to RF interference and new meter sets related to customer growth. Overall, the cost is estimated to be $0.70 million over the 2006 to 2021 timeframe.

g) Pole Replacement (C-7)

We expect there will be no pole replacements required to support the partial AMI deployment in Zone 4.

h) Communications Link from Meters to Data Center, WAN/LAN Servers (C-8)

In Scenario 17, we expect to incur Digital Signal Level 3 (DS3) costs. A DS3 is a high-capacity telecommunication circuit. We plan to install one DS3 to accommodate the additional traffic that is expected on our website. The bulk of the non-labor costs are associated with the leasing costs that we will incur from the telecommunication provider. We will also incur contractor costs in 2006, 2011, 2016 and 2021 associated with the installation and replacement of equipment related to upgrades to the communications infrastructure that will be discussed below in cost code C-10. Overall, the cost is estimated to be $0.96 million over the 2006 to 2021 timeframe.

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[35] We assumed one percent of all residential and less than 20 kW commercial meter installations will require an external antenna. For greater than 20 kW commercial meter installations, we have assumed that 20% of the installed meters will require an external antenna.

i) Install Cross Arms/Mounting (C-9)

There are no incremental costs associated with this cost category.

j) Purchase Network Communication Equipment and Hardware (C-10)

Through mid-2007, we plan to install 928 collectors. Once the radio frequency networks are operational, we will be able to determine the specific areas within Zone 4 that are not communicating with the network and determine whether a collector can be deployed to cover that location or whether it will be a RF "blind spot," and thus will not possess remote read capability.

The cost estimates for cost category C-10 also include the equipment costs associated with 10 packet routers. As discussed previously, we will install packet routers in order to ease congestion on the network and ensure that data is transmitted to the network in a timely manner. The equipment costs for the 18 MCC take-out points are also included in the cost estimates for this cost category. In order to make the unit operational, each MCC take-out point will need to have four radios installed.[36]

Table 3-23 describes the annual deployment volumes associated with the communication infrastructure.

[36] Other equipment is also needed to make the MCC take-out point operational. The costs associated with this equipment are discussed in cost category C-6.

Table 3-23 Communications Infrastructure Deployment Volumes			
Equipment	**2006**	**2007**	**2008**
Collectors	515	310	103
Packet Routers	7	3	0
MCCs	12	6	0

Throughout the course of the deployment, we expect to have various equipment failures. This will require us to incur additional labor and material costs to replace this failed equipment.[37] The communications infrastructure cost associated with this cost category is $1.45 million over the 2006 to 2021 timeframe.

As meters are installed, the installers and meter technicians will utilize an RF verifier tool to test whether the communication module is functioning properly. We will also be procuring Local Area Network (LAN) assessment tools to help troubleshoot problems when we determine meters are not communicating with the network. The estimated costs associated with procuring this equipment in 2006 is $56,000.

k) WAN/LAN Training (C-11)

There are no incremental costs associated with the training for the installation of WAN/LAN equipment.

l) Cost of Attaching Communication Concentrators (C-12)

In Scenario 17, cost category C-12 is used to capture the costs associated with various development tools licenses and fees. Non-labor costs of $50,000 are being charged to this cost category over the 2006 to 2007 timeframe.

[37] As in the full deployment scenario, we have assumed an annual failure rate of one-half of one percent.

m) Contracts to Retrieve Meter Data (C-13)

There are no contracts required to retrieve the meter data and services.

n) Dispatch and O&M of Field WAN/LAN and Infrastructure Equipment (C-14)

There are no dispatch and O&M costs associated with infrastructure equipment.

o) Electric Power for LAN/WAN Equipment and/or Meter Modules (C-15)

There are no incremental costs associated with this cost code.

3. Information Technology Infrastructure

As discussed in Section III of this volume, the IT infrastructure enhancements made necessary by partial AMI deployment will include meter installation systems meter read conversion systems and data management systems related to the collection, processing and billing of interval usage data.

a) Network Planning/Engineering (I-1)

As discussed earlier, we will be installing a communications infrastructure comprised of collectors, MCC take-out points, and packet routers. We will incur incremental labor costs of $0.66 million over the 2006 to 2008 period for the engineers and project support staff to design this infrastructure.

b) Computer System Set-up (I-2)

Our computing systems capacity will need to be increased in order to support AMI. As previously discussed, we will enhance existing and develop new applications. In Scenario 17, we are developing and enhancing additional applications to process the extensive volume of interval data that will be collected from meters to facilitate time-of-use and CPP billing. We are also enhancing SCE.com, our primary customer interface system. We will need to procure additional hardware, storage, and operating software, including 30 additional servers and approximately 1,100 Gb of additional storage. Given the data processing requirements associated with interval usage data, we will also need to increase the mainframe resources by 123 MIPS and 254 Gb in additional storage.

Additionally, we are planning to automate the asset tracking and work order aspects of the meter installation and removal processes and will require upgrading existing field laptops and providing additional laptops with GPS capability for the FSR installers. Incremental SCE FTEs and contractor resources will be hired to handle the design and installation of the new hardware. The total cost for the computing system enhancements and associated labor are estimated to be $6.35 million over the duration of the program.

c) Data Center Facilities (I-3)

No new data center facilities will be required.

d) Develop/Process Rates in CIS (I-4)

We will be enhancing existing and developing new applications to facilitate the meter supply chain management, meter change workflow, and meter read conversion processes. A critical element of this effort will involve verifying that the new applications or enhancements do not adversely affect the systems that process meter changes and meter reads and calculate bills. To ensure there are no adverse impacts, we will employ comprehensive testing techniques, such as regression, integration, and unit and system testing. We will engage contractor resources to handle these activities during the 2006 to 2007 timeframe. We estimate the cost for these activities is $222,000.

e) New Information Management Software Applications (I-5)

Our Customer Service organization will partner with our IT organization in developing system and business requirements for the revisions required at

SCE.com. They will also participate in testing the new website before it is launched for customer use. After the website is launched, they will identify system improvements to ensure customer friendliness and ease of use. We have estimated $0.17 million in labor costs associated with these activities over the 2006 to 2007 timeframe.

f) Records (I-6)

New applications will be developed and existing applications will be enhanced to support automating the meter change workflow and meter read conversion processes to accommodate the meter change volumes in this business case. The new data management systems including Usage Calculation, Service Billing and SCE.com will also require support. The costs associated with developing the system requirements and database schema is captured in this cost category. We estimate the need for additional contractor resources at a cost of $1.08 million over the 2006 to 2007 timeframe.

g) Update Work Management Interface to Process Additional Meter Changes (I-7)

Another critical element of system enhancement and development is designing the interfaces between the various systems and verifying that they are working as designed to ensure that information flows appropriately. We will engage contractor resources to handle these activities during 2006. We estimate the cost for these activities is $30,000.

h) Maintain Existing Hardware/Software that Translates Meter into Bills (I-8)

Our Billing Organization will partner with our IT organization in determining system requirements that will be needed to gather usage data and translate it into billing data. Once the system requirements are identified, they will also assist in the testing of new software functionality. We have estimated $1.3 million in project management and business analyst support labor costs associated with these activities over the 2006 to 2021 timeframe.

As detailed in the description for I-7, we will engage contractor resources to handle interface design and verification activities during 2006. In terms of the I-8 cost category, we estimate the cost for these activities is $177,000.

i) Process Bill Determinant Data (I-9)

As usage data is collected and processed, we expect that additional customer service representatives will be needed in the Billing Organization to manually process accounts that the system is unable to process due to usage validation failures. Our billing cost estimate is $3.4 million for these activities.

In Scenario 17, with the introduction of demand response rates, we will significantly increase the amount of usage data that is collected and processed. Instead of having one read and one time stamp per month for each account, we will now have 730 reads and 730 time stamps per month. In terms of our IT systems, we will also need to dedicate resources to define and develop processes which will support the rules that will determine whether data is processed by the system or whether it needs to be reviewed manually by a customer service representative. We will engage contractor resources to handle these activities during the 2006 to 2007 timeframe. We estimate the cost for these activities at $0.51 million.

j) Contract Administration and Database Management (I-10)

There are no incremental contract administration costs. The costs associated with infrastructure database management are included in cost code I-16.

k) Exception Processing (I-11)

As meter failures occur, we expect some accounts will fail billing system validations and will require manual intervention. This manual processing involves determining how a bill will be processed when a meter failure occurs during the middle of a billing period. Depending upon the nature of the meter failure, a judgment call is often required with regard to estimating consumption. Of the total meter failures, we estimate that 50 percent will require manual processing. In Scenario 17, with the introduction of new demand response rates, we expect that there will be additional exceptions that result during the billing process due to the significant amount of data that will be processed in order to calculate a bill. We will also be handling additional activities associated with processing rate changes for customers who opt-out of their TOU default rate. As such, additional customer service representatives will be needed to manually process these accounts to ensure that customers continue to receive timely and accurate bills. Our personnel cost estimates of $1.88 million over the 2006 to 2010 timeframe are based upon processing five accounts per hour for the first three years. As employees become familiar with how to handle these accounts, we expect their productivity to increase to 10 accounts per hour, beginning in 2009.

In terms of our IT systems, we will need to dedicate personnel to defining and developing the process by which exceptions are handled. We will engage contractor resources to handle these activities during 2006. We estimate the cost for these activities is $98,000.

l) License/O&M Software Fees (I-12)

We have not identified any additional license fees that may be required under the partial deployment scenario.

m) Ongoing Data Storage/Handling (I-13)

There are no incremental ongoing data storage/handling costs due to similar data capacity requirements in the "Business As Usual" case.

n) Ongoing IT Systems (I-14)

As discussed in Section III of this volume, we will be developing new applications and enhancing existing applications to facilitate the meter supply chain management, meter change workflow, and meter read conversion processes. Scenario 17 will require significant application enhancements, particularly those associated with the Usage Calculation System, in order to process the extensive volume of interval data. We will need to dedicate additional contract and SCE resources to support these activities. The ongoing O&M for these applications includes applications support, security administration, database administration support, maintenance, and enhancement activities and is provided from a mix of contract and SCE labor. The total estimated cost of this activity is $6.95 million during the 2006 to 2021 timeframe.

o) Operating Costs (I-15)

Once the communications infrastructure is fully operational, it will contain nearly 16,000 commercial meters with radios, 928 collectors, 10 packet routers, and 18 MCC take-out points. As the infrastructure is developed, we will need to phase in 8 incremental FTEs and additional contractors to handle the on-going management of this network. Based on our current experience with managing the network, our personnel estimate assumes that we will need 20 engineers and IT specialists for every 40,000 radios. The incremental labor and contractor costs from 2006 to 2021 are $9.6 million.

p) Server Replacements (I-16)

We expect to replace the computing systems hardware identified in cost category I-2 on the basis of a five-year technology refresh cycle. As such, the hardware refresh would occur in 2011 and 2016. We did not include a final refresh in 2021 based on our assumption that the entire AMI system will be obsolete and need to be renewed with new technology and supporting infrastructure. Contractor resources and incremental SCE FTEs will need to be utilized to handle the design and installation of the new hardware. Incremental SCE labor costs for database management are also included in this cost category. The costs for refreshing the computing systems and associated labor are estimated to be $13.01 million.

4. Customer Service Systems

This section will describe the Customer Services cost codes utilized in assigning costs for this Partial Deployment scenario. For our purposes, Customer Services include Call Center costs, Meter Order Processing, Customer Communications, and a portion of billing-related costs.[38] We expect to spend approximately $23.1 million in this cost categories over the entire analysis period. This cost category does not include meter reading and field services costs because these functions are essential to the Meter System Installation and Maintenance costs discussed in Section III of this volume.

Appendix A of the July 21, 2004 Ruling did not identify any "start-up and design" related costs in the Customer Service Systems cost category. We have, however identified some billing related "start-up" costs associated with the specification of security systems, the development of data retrieval strategies, network planning, and the meter RFP proposal specifications. These costs are included under cost codes C-1, C-5, I-1, and M-2.

a) Installation (CU-1 through CU-4)

This section will describe the one-time costs that are expected to be incurred during the installation process for AMI. Generally these costs are attributable to the implementation process itself, rather than on going operations. For the most part, these costs will no longer be incurred once the project installation phase is complete.

(1) Customer Records, Billing and Collections Work Associated with Roll-out of the Meter Change Process (CU-1)

The 2004 present dollar value of all costs in this cost code is expected to be $2.99 million over the duration of the analysis period. The majority of costs

[38] The majority of billing system installation and operating costs are included in the Information Technology section because cost codes I-9 and I-11 better described the billing related functions of "validating and creating billing determinate data" and "Exception Processing."

in this cost code relate to the processing of meter orders. Meter order processing costs are based entirely on the volume of anticipated meter change orders in excess of those that would normally be processed under normal business conditions. These costs are driven by routine change orders that fail to process initially in the automated meter processing system and must be manually reviewed as an exception and reprocessed. This is a labor-intensive process that is estimated to require approximately sixteen FTEs in the initial year of implementation (2006), and will drop off to three FTEs in 2007, two in 2008, one in 2009 and 2010. There will be no incremental meter order processing cost once the installations are complete. Total meter order processing costs over the duration of the analysis period are expected to be $1.52 million.

Billing has identified the need for additional personnel to process an expected increase in billing exceptions and to support their revenue protection activities. As discussed in cost category MS-12, we expect our installers to discover potential energy theft situations that need to be investigated during the deployment process. Our Billing Organization will contribute to the resolution of these potential energy theft situations by performing analysis, interfacing with the field personnel, potentially rebilling customers' accounts, and corresponding with customers. We have estimated a cost of $1.47 million for these activities over the 2006 to 2021 timeframe.

(2) Increased Call Center Activity During Installation Phase of the Partial Deployment (CU-2)

We expect a relatively small volume of calls will result from media messages introducing the change to the affected customers. We expect one-half of one percent of customers designated for AMI installation will call as a result of mass communications. This estimate is based on prior experience with similar mass communication campaigns. We expect a slightly larger volume of calls to occur as a result of the initial "meter change letter" that will be sent to all affected customers. We estimated that three percent of these customers would call if only a letter or bill insert is sent and four percent if door hangers are left after service is complete. The calls will result from the change letter, from the service personnel being observed on the property, and from door hangers. The three percent and four percent estimates are based on management's experience with other communications in which a service visit is required. In Scenario 17, we also expect increased call volume resulting from rate change letters and "opt-out" inquiries to our Call Center. First, we will notify qualifying customers that their rate will be changed to a CPP rate schedule. We estimate that five percent of customers will call when notified that their rate is being changed. The five percent estimate is based on our experience with other communications in which rate modifications are involved. Second, there will be customer calls related to opting out of the new rate. Our estimates assume 27 percent of customers call about opting out and 70 percent of those that call will actually choose to opt-out. Overall, we are expecting an increase of approximately 300,000 calls under Scenario 17 and the total cost of increased call volume resulting from partial AMI deployment is expected to be $1.1 million.

(3) Modification and Customer Support Costs for AMI Integration to the Outage Management Systems (CU-3)

SCE's Outage Management System (OMS) is expected to function as it does today, entirely independent of the new AMI infrastructure. Other than some IT contract costs ($0.17 million), we have not identified any other incremental implementation costs related to OMS.

(4) Process Meter Changes for new Meter Installation and DA Accounts (CU-4)

The Meter Services Organization (MSO) expects to incur costs of approximately $2.48 million, primarily during the installation phase in 2006, for engineering and sample testing of meters prior to installation. MSO's field metering installation work is classified as Meter System Installation costs in cost code MS-5. The Billing Organization expects to spend $0.15 million in this cost code, all in 2006. This covers exception processing work directly related to meter changes during the installation phase.

b) Operation and Maintenance (CU-5 through CU-10)

(1) Additional Rate Analysis Due to Multiple TOU Options (CU-5)

We expect an increase in on-going rate analysis work in our Billing Organization due to an increase in the number of customer inquiries spurred by the rate changes and the large number of meter changes taking place. Billing Organization costs in the CU-5 cost code are expected to increase by $0.13 million under Scenario 17. As new rates are introduced, we expect to experience an increase in the number of customer requests for rate analysis. These requests are handled by our Major Customer Division (MCD). MCD provides coordination between account representatives and major customers for rate analysis opt-out and contract revisions. Customers who are deciding whether to opt-out may want to request a rate analysis to determine if the rate assigned to them is the best rate to stay on or to determine if there is a more appropriate rate. The total cost for MCD associated with these activities is expected to be $0.23 million in cost code CU-5.

(2) Meter Reader and Customer Safety Related Costs (CU-6 and CU-7)

Cost codes (CU-6 and CU-7) relate to reduced customer safety and alternative safety measures, "because meter readers are no longer available." Although we recognize there is some foregone operational benefit to no longer having meter readers periodically inspecting our metering installations, we have no records relating to the frequency or value of our meter readers finding unsafe, or faulty electrical service equipment. Accordingly, we have not included any cost estimate in these two cost codes.

(3) Customer Education of Rate Changes (CU-8)

In Scenario 17, beginning in 2007, the Call Center expects to receive customer calls related to their first series of bills after changing rates. We projected that our customers would go through a learning curve period in which a declining percentage of customers would call after each bill is received after switching to the new rate. For Scenario 17, these rate-related calls are expected to increase call volume by approximately 40,000 calls in 2007 at an added cost in cost code CU-8 of $0.17 million. Web-based rate communication costs are estimated at $0.35 million in this cost code. MCD will also incur costs of $52,000 in cost code CU-8 related to developing materials for our customer account representatives and major customers.

(4) Customer Support for Internet Based Usage Data Communication (CU-9)

We expect to receive approximately 3,000 additional calls in 2007 from customers with questions related to their first review of usage data presented on SCE.com. As previously discussed, we projected that our customers would go through a learning period in which a declining percentage of customers would call after each session on SCE.com to review usage data. The total cost over the analysis period associated with these additional calls, which are charged to cost category CU-9, is estimated to be $12,000.

In Scenario 17, our Customer Service organization will incur costs related to the development of market research surveys to learn about customers' wants and needs so that the information learned can be applied to enhance the website. Costs will also be incurred related to assisting major customers in learning how to use the website and how to access their usage data. We will also provide support to the Customer Communications organization by handling customer telephone calls regarding complex website related questions. The costs for these web-based activities, which will be charged to cost code CU-9, are estimated to be $4.9 million. These web-based costs include the total cost of replacing the existing systems and we have identified over $4.1 million in offsetting benefits, which are included in benefit codes CB-8 and MB-1.

The increased use of internet usage data is also expected to result in additional Billing Organization costs of approximately $0.85 million.

(5) Outbound Communications (Mass Media Costs for Print, Radio and TV) (CU-10)

The most significant Customer Services cost increase attributable to AMI deployment is related to the mass media marketing costs, a portion of which are charged to cost code CU-10. The Customer Communications programs related to this scenario are expected to total approximately $9.5 million in this cost code. Another $6.8 million in Customer Communications and Marketing costs related to this Scenario are, by definition, included in cost code M-14 ("Customer Acquisition and marketing costs for new tariffs"). These will be described below in the "Management and Miscellaneous Other" cost category.

5. Management and Miscellaneous Other Costs

This cost category includes general overhead costs that span across two or more functional cost categories, such as project management and the administration of job skills training.

a) Buyout of Existing Itron Contract for Automatic Meter Reading (M-1)

There would be no change in the Itron AMR contract because the majority of AMR meters are located outside of Zone 4, and SCE is committed through 2011 to the current contract, including the AMR meters in Zone 4, which would no longer be read after 2006.

b) Meter RFP Process and Contract Finalization and Administration (M-2)

The development and review phases of the RFP process are expected to involve all major departments participating in the project. As a major participant in this process, the Billing Organization has included $62,000 in this cost code. All other participating organizations have included the costs associated with this process in the direct overhead costs associated with their respective start-up and installation cost estimates. The Procurement and Material Management Organization costs related to the preparation and review of the RFP were included in cost code MS-10, which was discussed previously in this section.

c) Customers' Access to usage Information (M-3)

We expect to incur approximately $0.63 million in exception billing costs attributable to the increased availability of usage information to the customer. Availability of such information combined with the more complex rate schedules is expected to heighten customer interest at a more detailed level than currently exists. The end result is expected to be an increase in the number of customer inquiries, both valid and invalid.

d) Employee Communication and Change Management (M-4)

The Billing Organization has included a total of $0.30 million in this cost code. This represents expected costs related to preparing and communicating AMI system information to employees and keeping them informed and up-to-date on the implementation of AMI and its related systems. We estimated $56,000 in additional cost for web related activities associated with employee communications over the duration of the analysis period.

e) Employee Training (M-5)

The M-5 cost code includes "systems and rate structures training." Training of call center personnel, meter readers, and meter test technicians is included in cost code M-10. There are two elements to employee training costs; the trainee-related cost of non-productive (seat) time spent in the classroom, and the cost of the trainer and training staff, including training materials, classroom preparation, etc. All trainee-related costs are included in the operational costs of each individual operating organization. Most of the training will be provided by our Job Skills Training (JST) Organization. The Billing Organization and the Call Center supplement the JST training with their in-department training as needed.

For the partial deployment case, the estimated cost of all JST training in cost code M-5 is $0.35 million for the duration of the analysis period through 2021. Billing Organization training costs in this cost code are expected to be $0.27 million for the same period. Employee communication programs on the web will add $0.25 million to this cost code. This will supplement the Billing Organization and JST training under this cost code, and it relates primarily to assuring that customer contact personnel have a clear understanding of the rates and rate options being introduced under this scenario.

f) Meter Reader Reroute Administration (M-6)

The cost of recycling and rerouting the non-communicating AMI meters has been accounted for in cost code MS-2, which was discussed previously in this section. These costs are being absorbed as a portion of the cost of the additional supervising FSR assigned to each of the three districts to supervise the AMI meter system installation process.

g) Overall Project Management Costs (M-7)

Partial AMI deployment will require the formation of a Program Management Organization similar to that anticipated for full deployment, but for a much shorter duration, since the meter installation phase of this scenario is only one year as opposed to five years for the full deployment case. For the partial deployment scenario, a program management team consisting of eight SCE middle management and two SCE staff support personnel will oversee the one year installation phase of the project. After installation, one SCE Program Manager and two staff personnel will remain to oversee the program through 2010. We also anticipate the need for as many as 10 contract personnel supporting the program management effort during the initial installation phase in 2006. Total Program Management costs for the duration of the partial deployment analysis period are expected to be $4.5 million.

Additionally, each of the major operating departments has estimated some project management costs to support the core project management team. Total project management costs for the operating organizations are expected to be $7.6 million. We have also determined that in order to meet the deployment schedule proposed in the July 21, 2004 Ruling, with deployment starting in 2006, there will likely be project planning tasks that should occur in 2005. However, since the July 21, 2004 Ruling directed the business cases to start in 2006, the 2005 costs are not included in this analysis.

h) Recruiting of Incremental Workers (M-8)

Implementation of the partial deployment AMI program would affect the recruiting and hiring process within the three most heavily affected organizations: Meter Reading, Call Center, and Billing. For the most part, the incremental cost of recruiting the anticipated increase in personnel has been included in the cost estimates for each organization separately in their respective cost codes. Because of the initial start-up impacts on FSMRO personnel, that organization has included $56,000 in this cost code.

i) Supervision of Contracts and Technology Personnel Assigned to Hardware and Systems Development (M-9)

These costs are reflected within the individual operational areas and no additional costs are included under this cost code.

j) Training for Other Traditional Classifications (M-10)

The overall training impact of this scenario was discussed previously in this Section under cost code M-5 relating to Systems and rate structure training costs. We estimate approximately $0.57 million will be spent training Call Center, Field Services and Meter Reading personnel under cost code M-10.

k) Work Management Tools (M-11)

Our Business As Usual operations include the cost of providing our management with the most up-to-date work management tools available. No incremental cost has been included for new or additional work management tools under any of the AMI scenarios.

l) Capital Financing Costs (M-12)

Capital and financing costs are included in the NPV calculations at SCE's long-term weighted average cost of capital.

m) Cost of Increased Load During Mid-peak and Off-peak Hours (M-13)

There is no change in the cost associated with mid and off-peak loads (M-13) under this scenario.

n) Customer Acquisition and Marketing Costs for New Tariffs (M-14)

Incremental marketing and customer education costs in this cost code combined with those described in cost code CU-10 above make up the total customer communications program described previously. This cost code includes $6.8 million of the $16.3 million to be spent on marketing and customer education programs that will be necessary to secure 80 percent of the AMI metered customers on CPP rates, and retain them on those rates for the duration of the analysis period. The remaining $9.5 million in marketing costs was discussed under cost code CU-10.

o) Risk Contingencies (M-15)

Overall program contingency costs have been estimated at $7.5 million. Risk contingencies related to this scenario are discussed in Section D. below.

B. Benefits

Table 3-24 summarizes the Scenario 17 benefits by category and compares them to Scenario 4 benefits. Scenario 17 is similar to Scenario 4 except it applies only customers in the densely populated communities of Zone 4. Table 3-24 compares benefits using the Ruling's assumptions and SCE assumptions for the value of avoided capacity.

Table 3-24 Summary of Benefits for Scenario 17 vs. Scenario 4 (000s in Pre-tax Present Value Dollars)				
Benefit Categories	**Scenario 4**		**Scenario 17**	
	Ruling's Assumptions	**SCE Assumptions**	**Ruling's Assumptions**	**SCE Assumptions**
Systems Operations Benefits	$307,333	$307,333	$20,655	$20,655
Customer Service Benefits	8,268	8,268	3,860	3,860
Management and Other Benefits	122,316	122,316	10,309	10,309
Demand Response DR-1 Benefits	325,722	172,100	38,111	20,294
Demand Response DR-2 Benefits	41,008	41,008	4,756	4,756
Total Demand Response Benefits	366,730	213,108	42,867	25,050
TOTAL:	$804,648	$651,025	$77,691	$59,874

The following sections will describe only those benefit codes that were actually used in this preliminary analysis. Appendix H contains a discussion of all benefit codes identified in the Ruling, whether we actually included them in this analysis or not.

1. System Operations Benefits (SB-1 through SB-13)

In this section we address the potential "system operations" benefits expected to result from partial deployment of AMI to approximately 325,000 SCE customers in Zone 4. Appendix A of the July 21, 2004 Ruling identified 13 such potential benefits. In our initial review of these potential system operations benefits, we have been able to quantify $29.3 million in potential savings over the duration of the analysis period. These savings are expected to come from only three of the 13 System Operations Benefit codes. We expect some net benefit from one other (SB-7), which we are not able to quantify at this time. Eight of the potential areas of benefit identified in the Ruling are either already being experienced by SCE, or have associated costs that more than offset the anticipated savings.

a) Reduction in Meter Readers, Management and Support (SB-1)

This is the largest area of benefits expected to accrue from partial implementation of AMI. We expect 25 meter reading positions to be eliminated, resulting in total cost savings of approximately $18 million over the analysis period. As was the case in the full deployment scenario, we expect AMI to give us the ability to remotely read approximately 94 percent of all meters in Zone 4 (94% of 325,000 = 305,000). The remaining 20,000 meters, that cannot be read automatically, will continue to be read manually on a monthly basis.[39] We do not expect to eliminate any of the existing meter reader supervisor positions since each of the three major districts have only one supervisor who supervises both FSRs and meter readers. There will continue to be a need for these positions after AMI is deployed.

b) Field Service Savings (SB-2)

We currently complete approximately one-half of all "turn-off" and "turn-on" meter orders without having to actually turn the meter on or off. This situation occurs when a "turn-on" order can be matched to a "turn-off" order for the same location, on or about the same day. Such orders can be completed merely by taking a meter read, which currently requires a visit to the site at an average cost of approximately $17 per order for "next-day" service. Virtually all of these special meter reads for matched on/off meter orders could be eliminated and replaced with the daily AMI meter read. This

[39] The remaining 30% of the meters with which we are unable to communicate are scattered throughout the Zone 4 area and are generally not adjacent to one another, thus making routine meter reading less efficient than it is today.

benefit would result in the elimination of three FTEs and a savings of approximately $2.5 million over the duration of the analysis period.

c) Phone Center Savings from Billing Inquiry Reductions Due to More Accurate Billing (SB-4)

Billing inquiries today are received for several reasons, only one of which is an inaccurate meter read. Based on a study using 2003 data, 22,791 calls were a result of meter reading errors. We used this number as a percentage of all calls to determine the percent of calls in subsequent years that would be projected as meter read error calls for each operational scenario. For the business case, we assumed that 100 percent of these calls would be avoided with automated meter reads.

For the partial deployment scenario, Table 3-25 shows the number of avoided calls that may result from the complete elimination of meter reading errors. Using the average number of Billing Inquiry calls answered per FTE in the Billing Inquiry specialty support group in 2003 (3,376), we are estimating a levelized reduction of 0.46 FTEs by 2007. This results in a total cost savings of $253,000 over the duration of the analysis period.

Table 3-25
Reduced Phone Calls – Partial Deployment

	2006	2007	2008	2009	2010	2011
Scenario 14	0	1,553	1,553	1,553	1,553	1,553

2. Customer Service Benefits (CB-1 through CB-13)

The July 21, 2004 Ruling identified 13 potential customer service benefits. Our review of these potential areas of benefit resulted in anticipated annual savings of approximately $3.9 million from just two areas over the sixteen-year analysis period of the partial deployment scenario. Savings attributable to improved billing accuracy (CB-1) due to the elimination of estimated bills and timelier billing due to elimination of meter accessibility problems results in savings of $0.98 million. In addition, we have recognized $2.9 million in operational cost offsets to accommodate those customers who are already on demand response rates or who otherwise use the web based programs for energy management information (CB-8).

For a discussion of all other Customer Service benefit codes as they relate to partial deployment of AMI, see Appendix H.

3. Management and Other Benefits (MB-1 through MB-10)

We expect to reduce costs by approximately $0.65 million through 2021 by decommissioning 25 hand-held meter reading devices. Typically, these devices would be replaced every five years. This is a cost that would no longer be incurred and is classified as a benefit in the MB-1 category. The MB-1 benefits also include $1.2 million in website equipment offsets reflecting the avoided cost of future investments resulting from overall website infrastructure improvements needed to meet AMI program needs.

The only other Management and Other benefit code used in this analysis is MB-4 (Reduced Meter Inventory Costs). Though we do not expect an overall decrease in inventory costs, we have used this benefit code to include the avoided cost of purchasing approximately 5,100 conventional new and replacement meters each year for the full duration of the analysis period. As discussed in the Business As Usual case (see Appendix G) the material cost of 5,100 new and replacement non-AMI meters each year is significantly different than the replacement cost of these same 5,100 meters each year using AMI meters. For this reason, the total cost of all new and replacement AMI meters has been included in all AMI scenarios in cost code MS-3. The avoided cost of not purchasing conventional meters for customer growth and routine replacements is included in benefit code MB-4. For the partial deployment scenarios, this avoided cost is $8.5 million over the duration of the analysis period.

The remaining areas of potential Management and Other benefits, as identified in the July 21, 2004 Ruling, are discussed in Appendix H.

4. Demand Response Benefits

This scenario assumes that 80 percent of eligible customers are defaulted to CPP-F rates (residential) or CPP-V rates (C&I below 200kW) and those customers stay on those rates for the full duration of the business case. For the purposes of the analysis, we assumed that the customers opting-out of the CPP default rate would choose equally between a TOU rate and their otherwise applicable tariff. Our approach to estimating the demand response benefits is the same as for Scenario 4, except that we used our cooling degree hours and air conditioning market penetration for Zone 4.

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in CPP or TOU rates. Our methodology and analysis of Value of Service Loss by scenario is presented in Appendix J. For this scenario, the Value of Service Loss is approximately $36.7 million ($2004 present value), reducing the total demand response benefit from $42.9 to $6.2 million.

C. Uncertainty and Risk Analysis

1. Operational Cost Uncertainty and Risk Analysis

We performed an operational cost and benefit risk assessment of this partial deployment scenario based on the specific cost and benefit data discussed in the sections above. For analytical purposes, this operational risk assessment focuses on the 54 cost codes that comprised nearly 80 percent of the overall cost. Once the appropriate cost codes were identified, we developed the most likely high and most likely low ranges for each of the cost codes. We then applied a Monte Carlo statistical approach to create a probabilistic range around our estimate.

a) Significant Cost Areas

For this partial deployment scenario, the total present value cost estimate (prior to adding contingencies) for full AMI deployment is $157.5 million. In the discussion that follows, we will focus on five of the significant cost areas which represent over forty percent of the total cost for this scenario.

(1) Cost Code MS-3 – Meter Purchasing

Cost code (MS-3), involving the cost of purchasing meters and meter-related communications equipment in this partial deployment scenario, is estimated at over $33 million. We estimated a range for this cost code to be: plus 20 percent and minus 15 percent. The high end of this range is based on our historical experience with price differences that occur between an RFI and the ultimate final contract. We find that vendor price increases of as much 20 percent are due to better understanding of scope, warranty requirements, and contract terms and conditions. We based our estimate on vendor quotes we received in the RFI. The range also reflects the uncertainty of meter failure. The low range is based on the fact that current meter technology is aging, and potential vendors have informally indicated that lower prices are possible for high-volume orders.

(2) Information Technology Operating Costs

Information Technology ongoing operating costs, estimated at $9.4 million, varied by plus or minus 20 percent.

(3) Server Replacements

Information Technology computing system replacement costs, with non-labor estimated at $7.4 million, varied by plus or minus 40 percent.

(4) Data Center Computer System Implementation

Non-Labor associated with data center computer system implementation, estimated at $5.4 million, was also estimated at plus or minus 40 percent.

(5) Out-bound Communications

Marketing Costs for outbound communications and mass media are estimated at $8.9 million and varied by plus 12 percent and minus 4 percent.

b) Monte Carlo Sensitivity Analysis Results

Using the cost ranges outlined above, the application of the Monte Carlo statistical analysis of costs resulted in a range of $150.8 million to $168.4 million around the estimated cost of $157.5 million for this scenario. The statistical analysis indicates that our cost estimate has about a 31 percent confidence level. This means that the project has a 69 percent chance of overrunning.

c) Contingency

We determined that contingency should be applied to the start-up and installation activities. We also believe that a 90 percent confidence level is reasonable for this type of project. Based on the analysis results, we applied a contingency of $7.5 million across the start-up and installation phases in order to achieve this confidence level.

2. Operational Benefit Uncertainty and Risk Analysis

The primary operational benefits relate to the reduction in meter readers and result in aggregate operational savings of $17.9 million. We do not expect any variation because the forecast reduction is solely a function of the AMI system communication coverage that is designed to reach 90 percent of the meters. The other identified operational savings were less than the threshold we used for analytical purposes. As a result, we did not include any operational savings in the statistical analysis.

3. Demand Response Risk Analysis

We believe that Scenario 17 demand response results are implausible for a number of reasons. First, we believe that it is unlikely that CPP rates would be imposed on a quasi-voluntary (opt-out) basis on the mass-market without first testing customer acceptance of TOU rates on an opt-out enrollment basis.

Next, we believe that if default enrollment of CPP was implemented, it is highly unlikely that 80 percent of customers would adopt the CPP rate over the entire 16-year study period. The SPP found that four to six percent of customers chose to drop the CPP-F rate after the first year of the experiment despite an offering of incentive payments to continue participation in the program in 2004, and these were customers who volunteered (or opted-in) in the first place. Moreover, a shadow-bill analysis of SPP CPP-F customers found that 26.3 percent actually had higher bills than they would have if they had stayed on their otherwise applicable rate. Over time, customers who experience higher bills will likely opt out to a more favorable rate.

Another key, but unlikely assumption is that all 80 percent of customers on CPP-F and CPP-V would respond over the 16-year period at the same level as customers in the SPP experiment. As noted above, the SPP experiment offered customers a $175 incentive for their participation in 2003. These customers were opt-in (affirmative enrollment) rather than default enrollments. Even though we include significant expenses for customer education and awareness, as well as notification of CPP events, it is unlikely that the entire population that defaulted on to the rate on average would be as informed and as responsive as SPP customers. Earlier, we described concerns and uncertainties associated with whether AB1-X would preclude a default implementation of CPP.[40]

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[40] *See* Volume 1, Section II.

D. Net Present Value Analysis

Table 3-26 summarizes the overall pre-tax costs and benefits of Scenario 17. Also shown is the after-tax NPV for this scenario on a cash flow basis, and the present value of the revenue requirement over the 16-year analysis period.

Table 3-26
Summary of Cost/Benefit Analysis for Scenario 17[41]
($ Millions)

Costs	Benefits	Pre-tax Sub-Total	After Tax NPV	Rev. Req. NPV
($164.2)	$77.7	($86.5)	($60.9)	($129.9)

Scenario 17 results in a negative Revenue Requirement Present Value of $129.9 million and does not support the implementation of partial AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the scenario 17 analysis, plus the recovery of SCE's net investment in any removed meters, plus the rate of return and tax impacts of the AMI-related investments.

If SCE's recommended assumptions for computing demand response benefits described in Appendix D were used as shown in Table 3-26 above, the negative Revenue Requirements would be $184.1 million, as shown in Table 3-27 below.

Table 3-27
Summary of Cost/Benefit Analysis for Scenario 17 ($Millions) Using SCE's Assumptions for Avoided Resource Value

Costs	Benefits	Pre-tax Sub-Total	After-Tax NPV	Rev. Req. Present Value
($164.2)	$59.9	($104.3)	($71.5)	($147.7)

41 This table was prepared using the July 21, 2004 Ruling's assumptions for avoided resource value.

VI.

REVENUE REQUIREMENT AND CUSTOMER IMPACT ANALYSIS

The purpose of this section is to present our revised preliminary estimated net AMI-related revenue requirement and customer impacts for the years 2006 through 2021 for the full deployment Scenario 4 and partial deployment Scenario 17.[42] The Scenario 4 and Scenario 17 revenue requirements were developed based on the operating expenses and investment-related costs presented in Sections IV and V, respectively.

Table 3-28 provides the estimated net AMI-related revenue requirement and average customer monthly dollar impacts for Scenarios 4 and 17.

The estimated net AMI-related revenue requirement impacts by year for each scenario are calculated by subtracting the expected AMI benefits-related revenue requirement reductions from the estimated AMI cost-related revenue requirement. For illustrative purposes, SCE has also calculated a customer monthly dollar impact by year for each scenario. In order to calculate the average customer impacts, SCE utilized the total system retail customer forecast as presented in SCE's 2004 LTPP testimony filed on July 9, 2004 in R.04-04-003.

A. AMI-Related Revenue Requirement Increases

The AMI-related Revenue Requirement increase is comprised of two components: 1) New Meter Revenue Requirement, and 2) Stranded Cost Revenue Requirement. The New Meter Revenue Requirement represents the recovery of anticipated O&M expenses and capital costs associated with expected rate base amounts including depreciation,

[42] Due to the July 21, 2004 Ruling's prescribed 2006-2021 analysis period, the revenue requirement analysis does not include recovery of the remaining AMI-related plant investment as of the end of 2021, primarily for meters which would be installed or replaced between 2007 and 2021. These unrecovered costs [of approximately $58 million in unrecovered net plant for the full-deployment scenario (Scenario 4), and $3.4 million for the Zone 4 partial-deployment scenarios (Scenario 17)] would be a continuing ratepayer obligation post-2021, although they also would be expected to provide a useful life past 2021, due to the underlying assets' 15-year life and their later in-service dates.

applicable taxes and return on rate base calculated at the Commission-authorized rate of return.[43] The return on rate base amounts included in the Revenue Requirements presented in Table 3-28 uses our currently authorized rate of return on rate base of 9.07 percent.

As discussed in this volume, new meters will be placed in service over a five-year period (2006 through 2010). As the new meters are deployed, the existing or replaced meters will become stranded costs and the undepreciated balance, including anticipated negative net salvage, associated with these meters must be recovered in rate levels. As such, SCE proposes to amortize the stranded meters undepreciated net investment over the five-year new meter deployment period which will commence on January 1, 2006 and has reflected this proposal in this revenue requirement analysis.

The net investment of the stranded meters will include plant and accumulated depreciation. The stranded cost revenue requirement also includes amortization, applicable taxes and an authorized return on rate base. Applicable tax regulations allow us to deduct any remaining tax basis associated with the stranded meters as an abandonment tax loss.[44] In addition, we will also take an immediate tax deduction for costs incurred in the removal of the existing meters.[45]

B. Expected Revenue Requirement Reductions

In order to estimate the net AMI-related revenue requirement impacts, the expected cost savings derived from the AMI benefits have been deducted from the AMI cost-related revenue requirement increase. The cost savings or revenue requirement reductions

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[43] SCE has assumed a 15-year recovery period associated with the new meters.

[44] *See* Treas. Reg. 1.167(a)-8(a)(4).

[45] Removal-related costs are not required to be capitalized for tax purposes because removal of an asset is part of the life cycle of the asset being removed.

include: (1) Customer Service-related O&M reductions; (2) existing meter revenue requirement reductions; and (3) procurement cost reductions due to demand response.

Table 3-28
AMI Revenue Requirement
(000s of Dollars)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Scenario 4 - Full Deployment-DR-CPP-Opt-20 Contingency																
AMI Meter Installation Revenue Requirements	136,791	165,143	214,272	236,392	256,514	220,111	210,052	204,676	197,201	194,405	160,672	160,304	155,206	149,824	144,891	125,613
Stranded Cost Revenue Requirement - 5 year	116,136	111,876	103,474	72,094	126,892	-	-	-	-	-	-	-	-	-	-	-
Less:																
Expected O&M Reductions	(42)	(6,746)	(22,138)	(35,052)	(52,883)	(60,329)	(62,589)	(64,701)	(67,161)	(69,451)	(72,071)	(74,534)	(77,362)	(79,522)	(81,696)	(84,033)
Meter Revenue Requirement in Rates	(2,906)	(1,952)	(4,790)	(4,790)	(4,790)	(4,790)	(4,790)	(4,790)	(4,790)	(4,790)	(4,790)	(4,790)	(4,790)	(4,790)	(4,790)	(4,790)
Expected Procurement Reductions	(53)	(10,502)	(20,948)	(31,500)	(39,169)	(41,791)	(42,346)	(42,914)	(43,487)	(44,073)	(44,660)	(45,262)	(45,867)	(46,487)	(47,110)	(47,749)
Total Net AMI-related Rev Req Impact	**249,926**	**257,818**	**269,870**	**237,145**	**286,564**	**113,201**	**100,327**	**92,270**	**81,763**	**76,090**	**39,150**	**35,718**	**27,187**	**19,025**	**11,295**	**(10,959)**
Avg Monthly Customer Dollar Impact	**4.33**	**4.41**	**4.55**	**3.94**	**4.70**	**1.83**	**1.61**	**1.46**	**1.28**	**1.17**	**0.60**	**0.54**	**0.40**	**0.28**	**0.16**	**(0.16)**
Scenario 17 - Partial Deployment-DR-Zone4-CPP-Opt-20 Contingency																
AMI Meter Installation Revenue Requirements	49,278	32,418	25,770	23,710	23,698	22,533	17,657	16,809	16,432	16,049	17,315	16,756	16,379	16,041	15,699	10,968
Stranded Cost Revenue Requirement - 5 year	10,454	10,068	9,314	6,488	11,423	-	-	-	-	-	-	-	-	-	-	-
Less:																
Expected O&M Reductions	(42)	(2,243)	(3,790)	(3,913)	(4,171)	(4,217)	(4,371)	(4,519)	(4,688)	(4,847)	(5,026)	(5,197)	(5,391)	(5,543)	(5,694)	(5,858)
Meter Revenue Requirement in Rates	(275)	(349)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)
Expected Procurement Reductions	0	(3,799)	(3,864)	(3,929)	(3,994)	(4,059)	(4,124)	(4,189)	(4,254)	(4,319)	(4,384)	(4,449)	(4,514)	(4,579)	(4,644)	(4,704)
Total Net AMI-related Rev Req Impact	**59,415**	**36,094**	**26,969**	**21,896**	**26,497**	**13,798**	**8,702**	**7,642**	**7,031**	**6,424**	**7,446**	**6,651**	**6,015**	**5,459**	**4,901**	**(53)**
Avg Monthly Customer Dollar Impact	**1.03**	**0.62**	**0.45**	**0.36**	**0.43**	**0.22**	**0.14**	**0.12**	**0.11**	**0.10**	**0.11**	**0.10**	**0.09**	**0.08**	**0.07**	**(0.00)**

Application No.:	A.05-03-
Exhibit No.:	SCE-4
Witnesses:	D. Berndt P. De Martini R. Garwacki D. Kim L. Oliva C. Silsbee M. Whatley

SOUTHERN CALIFORNIA EDISON

An *EDISON INTERNATIONAL* Company

(U 338-E)

Testimony Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism

Volume 4 - Appendices

Before the

Public Utilities Commission of the State of California

Rosemead, California

March 30, 2005

Volume 4 - Appendices

Table Of Contents

Appendix A

Witness Qualifications

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF DAVID L. BERNDT

Q. Please state your name and business address for the record.

A. My name is David L. Berndt, and my business address is 2131 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the manager of Meter Strategy Integration in the Customer Service Business Unit. My primary responsibilities are planning, supervising staff, and supervising projects involving the metering process and the selection of new meter types.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science degree in Chemical Engineering from the California Polytechnic University at Pomona in 1986. I have been with SCE for 13 years and have worked in various supervisory and management positions in the Customer Service Business Unit, including positions as a field engineer, product manager, and service center superintendent.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibits SCE-2, SCE-3, and SCE-4 *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY OF PAUL J. DE MARTINI

Q. Please state your name and business address for the record.

A. My name is Paul J. De Martini, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the AMI program manager for Information Technology. My responsibilities include managing the development of the information technology business case. I also lead the development of the Information Technology product lifecycle management competency.

Q. Briefly describe your educational and professional background.

A. I am currently a Fellow of the Wharton School at the University of Pennsylvania and received a Master of Business Administration (M.B.A) degree from the University of Southern California and a Bachelor of Science (B.S.) degree in Applied Economics from the University of San Francisco. I completed a Certificate, with distinction, in Project Management from the University of California, Berkeley. I have twenty-seven years of combined experience in utility and unregulated energy services operations, systems development, cost estimating, product development and business development. I have been at Southern California Edison for over two years. Relevant experience prior to joining Southern California Edison, I was Vice President of the Energy Strategy practice at ICF Consulting in 2000-2002 with a focus on demand response, advanced metering and distributed generation technologies. Earlier, I was Vice President of Integrated Services at PG&E Energy Services in 1996-1999, and at Pacific Gas and Electric

Company from 1977-1995, where I held a number of managerial positions involving electric systems operations, project management, and project cost estimating and project risk analysis.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibits SCE-2, SCE-3, and SCE-4, entitled *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF JOHN R. FIELDER

Q. Please state your name and business address for the record.

A. My name is John R. Fielder, and my business address is 8631 Rush Street, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am Senior Vice President of Regulatory Policy and Affairs. My organization is responsible for regulatory policy and matters involving state and federal regulatory bodies.

Q. Briefly describe your educational and professional background.

A. I received a Master of Business Administration from UCLA in 1970 and a Juris Doctor Degree from Pepperdine University in 1978. I am a member of the State Bar of California.

Upon graduation from UCLA in 1970, I was employed by the Organization and Procedures Department of Southern California Edison. Three months later I was called to active duty in the Army and served three years. I returned to Southern California Edison and joined the Data Processing Department (now Information Technologies). I held supervisory positions in Administration, Quality Assurance, and Technical Support. In 1987, I became Manager of Information Technologies, and on January 1, 1989, Vice President responsible for Information Technologies. On February 1, 1992, I assumed my current position.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE-1, entitled *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF RUSSELL D. GARWACKI

Q. Please state your name and business address for the record.

A. My name is Russell D. Garwacki, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. My current responsibilities include managing the Load Research and Rate Design functions within SCE's Regulatory Policy and Affairs (RP&A) department.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Arts degree in Economics from Whittier College in 1980 and a Master of Arts degree in Economics from Claremont Graduate School in 1983. I have been employed by SCE since 1983. From 1983 to 1993, I worked in the load research area of RP&A, ultimately supervising the group. During that time, I gained an understanding of sample design, cost allocation, and other regulatory policies and procedures. In 1994, I joined the Customer Service Business Unit (CSBU) as the Credit Analysis Manager, working to reduce both write-off and credit operational costs. From 1997 to 1999, I managed the Measurement and Efficiency group, delivering process improvements for CSBU's Field Services, Credit, Payment, and Customer Communication Center functions. From 1999 to 2004, I managed various CSBU activities including Job Skills Training, Internet Delivery, Benchmarking, and various technical support functions. In 2004, I returned to RP&A to assume my current responsibilities.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE-4, entitled *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY OF DOUGLAS H. KIM

Q. Please state your name and business address for the record.

A. My name is Douglas H. Kim, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the project manager of the AMI business case project in the Customer Service Business Unit. My primary responsibilities are work-planning, developing methodology, framework and analyses for the AMI business case; and managing the overall project activities.

Q. Briefly describe your educational and professional background.

A. I received a Master of Business Administration (MBA) degree from UCLA Anderson School of Management in 1996 and a Bachelor of Science degree in Engineering from Harvey Mudd College in 1982. I joined Edison International in 1996 to work in the corporate strategic planning and new business development group. My primary responsibility was to work as an internal business consultant for various projects across different Edison businesses. I joined SCE in 2001 and have since been primarily involved in business planning and various analytical activities.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibits SCE-1, SCE-3, and SCE-4 entitled *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF LINDA R. LETIZIA

Q. Please state your name and business address for the record.

A. My name is Linda R. Letizia, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company (SCE).

A. I am a Manager of Special Regulatory Projects in the Regulatory Policy and Affairs Department, and have responsibility for the management, development, and presentation of various ratemaking showings before the California Public Utilities Commission.

Q. Briefly describe your educational and professional background.

A. I graduated from the University of California at Davis in 1980 with a Bachelor of Science degree in Mathematics. I have been employed by Southern California Edison Company since 1984. Since joining SCE, I have held various positions in the Regulatory Policy and Affairs Department. My responsibilities have included revenue allocation and rate design, the preparation of pricing studies and analyses, and the development of revenue requirements and ratemaking proposals for numerous regulatory proceedings before the California Public Utilities Commission. I have also been employed in the Capital Recovery Section and Corporate Budgets Section of the Controller's Department.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibits SCE-2 and SCE-3, entitled *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF LAWRENCE M. OLIVA

Q. Please state your name and business address for the record.

A. My name is Lawrence M. Oliva, and my business address is 22 Via Del Tesoro, San Clemente, CA, 92673.

Q. Briefly describe your present responsibilities.

A. I am Managing Director of Corepoint Associates, Inc., and provide consulting services to clients in the energy sector.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science degree in Civil Engineering from Southern Methodist University in 1972. I completed all required course work toward a Masters of Architecture degree in Urban Design at Virginia Polytechnic Institute and State University in 1974. I began my consulting career in 1974 with SCS Engineers, Inc., and worked as a staff engineer on consulting assignments in the energy and environmental field for the federal government. I joined Resource Planning Associates in 1977 as an Associate and provided consulting services to the U.S. Department of Energy and private clients. In 1984, I joined Putnam, Hayes and Bartlett, Inc., and provided consulting services primarily to electric and gas utilities in a variety of areas including power plant economics, power contracts and alternative energy. I became a principal in the firm in 1987. In 1995, I joined Arthur Andersen, LLP, as a principal and was elected to the partnership in 2001. I provided consulting services and led consulting practices for the firm in electric utility deregulation and transmission organization transformation. In 2002, I joined Navigant Consulting, Inc. as a Managing Director and led a consulting practice in transmission organization development. In 2003, I founded Corepoint Associates, Inc., and provide consulting services to clients in the energy industry.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibits SCE-3 and SCE-4, entitled *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF CARL H. SILSBEE

Q. Please state your name and business address for the record.

A. My name is Carl H. Silsbee, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am Manager of Regulatory Economics in the Regulatory Policy and Affairs Department. In this position, I am responsible for marginal cost studies and related studies to support rate design, performance based ratemaking, and a variety of special projects. I have held the position since November 1985.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor's degree in Engineering from Harvey Mudd College in 1974 and a Master's degree in Engineering-Economic Systems from Stanford University in 1975. I joined Southern California Edison in 1981. Prior to my present position, my responsibilities have included coordinating and preparing operating and maintenance expense forecasts for general rate cases, preparing revenue requirement analyses in support of Certificate of Public Convenience and Necessity (CPCN) applications, and filing, avoided cost pricing for qualifying facilities and supporting wholesale rate case applications before the Federal Energy Regulatory Commission.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE-4, entitled *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure*

Deployment Strategy and Cost Recovery Mechanism, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY OF MICHAEL A. WHATLEY

Q. Please state your name and business address for the record.

A. My name is Michael A. Whatley, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the Integrated Planning Manager in SCE's Resource Planning & Strategy group. In that capacity, I am responsible for managing aspects of SCE's Long Term Resource Plan (LTRP) and directing scenario analyses in support of the LTRP. My position also requires me to provide recommendations on emerging issues including forecasts for needed generation, economic evaluation of new supply-side and demand-side resources, and establishing long-term market price forecasts and scenarios.

Q. Briefly describe your educational and professional background.

A. I earned my Bachelor of Science in Nuclear Engineering from the University of California, Santa Barbara. I have over 12 years experience in the California energy sector addressing natural gas and electric power issues. I joined SCE in March 2003 as Integrated Planning Manager. I have previously held the position of Manager, Systems Dynamics for Edison Mission Energy where I conducted technical analyses for various business development opportunities. I have also held positions in Edison International's Strategic Planning & New Business Development group, in SCE's Energy Supply & Marketing department and for SCE at the San Onofre Nuclear Generating Station.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE-4, entitled *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF LYNDA L. ZIEGLER

Q. Please state your name and business address for the record.

A. My name is Lynda L. Ziegler, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. As Director of the Customer Programs and Service, I am responsible for market research, strategy and business planning for the customer service business unit, regulatory, customer satisfaction and communication, market management and communication, electric transportation, consumer affairs, energy efficiency and load management programs, as well as program/product development.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science degree in Marketing from Cal State University, Long Beach, in 1982, and an MBA from Cal State University, Fullerton, in 1988.

From 1973 through 1978, I was a District Manager with Skil Power Tools in charge of a million dollar sales territory. From 1978 to 1981, I was a Marketing Account Executive, developing marketing and sales promotion campaigns for various consumer goods corporations.

In 1981, I joined the Southern California Edison Company. I have held a number of different positions, several in the energy-efficiency arena. I have been a program planner, a field supervisor, major account executive, and

Manager of Energy Efficiency Programs. Outside of the energy-efficiency and demand response arena, I have served as a Customer Service Manager, Service Planner, and Credit Manager.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE-1, entitled *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

Appendix B

AMI Technology Selection Assumptions for Business Case Analysis

APPENDIX B

AMI TECHNLOGY SELECTION ASSUMPTIONS FOR BUSINESS CASE ANALYSIS

In Attachment A to the July 21, 2004 Ruling, we were required to design our business case around certain functional requirements of the meters and supporting network, which included specific a number of required technological and operational functionalities. This section describes our chosen metering and communications infrastructure solution and how this solution was selected. Additional details of the selected technology and how it would be applied in the two best scenarios is included in the business case analysis in Volume 3. This appendix only describes the technology used in our business case analysis and does not describe the technology selection for our proposed Advanced Integrated Meter development project.

The selection of an appropriate AMI technology is fundamental to the business case analysis required by the Commission. AMI system design should appropriately balance technology risk with our primary obligation as a utility whose principal objectives include operational and customer service excellence. Because the AMI system will be a key part of SCE's core business transactions system, only proven technologies with significant and successful field testing should be considered for deployment in the AMI business case analysis.

A. Background on Technology Selection Process

In order to identify the appropriate AMI system for this business case analysis, we issued a vendor Request for Information to 23 potential respondents who have some level of experience with various metering and communications technologies. For confidentiality reasons and to avoid negatively impacting a possible future bid, we will not be disclosing the names of the vendors or any identifying details of their RFI responses. In the RFI, we required that the AMI solution must conform to the guidelines established by the WG3

Functional Requirements sub-team. A high-level summary of our interpretation of these guidelines is provided in Table B-1 below:

Table B-1
Summary of Required Functionality

Elements	Description
Estimated Meter Quantity	Residential: 3,962,000 < 20 kW C&I: 586,621 20-199 kW C&I: 143,787
Data Interval	From 15 minute to hourly increments
Collection Methods	Remote with manual read capability
Collection Frequency	Daily with on-demand read capability. Customer access to personal energy usage data with sufficient flexibility to ensure that changes in customer preference of access frequency do not result in additional AMI system hardware costs
Data available to Customer	Previous days data available to SCE next day by 8:00 a.m./Same day (near real-time) capabilities for subset of customer population
Customer Data Interface capabilities	KYZ output and/or other near real-time usage data presentation capability
Remote meter programming capability	Required

In response to our RFI, we received proposals from 18 vendors. Once the proposals were received, we used criteria identified in the RFI to evaluate the responses, as set forth below in Table B-2. These criteria are important because they are fundamental to balance system cost and service excellence. The criteria were weighted based on our experience in developing and deploying past technology solutions. A cross-functional team of SCE subject-matter experts was assembled to assess the vendor responses. The team addressed information gaps that, if unresolved, could significantly expose our ratepayers to unnecessary risk. Select vendors were contacted and provided with the opportunity to respond.

It is important to note that none of the 18 vendors contacted provided a response claiming commercial availability of a fully-integrated ("under the cover") metering solution with two-way ALC interface with end-use devices such as AC thermostats (providing set-back functionality rather than operating as an on-off load switch). In fact, the majority of the respondents claimed that their AMI solution would be compatible with and/or would possess the ability to interact with future (*i.e.*, yet to be developed) modules that could facilitate ALC and/or in-home usage information devices. A handful of respondents did have commercially available load switches (on/off capable) to control one or more end-use devices, but these would not be categorized as possessing ALC functionality. A real ALC technology option with integrated ALC does not yet appear to exist.

From this RFI process and based on the evaluation criteria, we selected the most appropriate technology based on the July 21, 2004 Ruling's required functional specifications.

Table B-2
AMI Request for Information Criteria

Evaluation Criteria	Description	Weighting
Reliability	The AMI technology solution's capability of ensuring data is not lost in the event of a component failure. Adequate redundancy needs to be balanced with cost considerations to maximize cost effective, reliable performance.	30%
Functional Requirements	The conformity of the AMI technology solution's functionality with the functional requirements of the RFI.	30%
Expected coverage	The AMI technology solution should reach at least 90% of SCE's customer base.	20%
Adherence to SCE (IT)	The ability of the AMI technology solution to reduce project complexity, costs, and risks.	20%

Standards		

B. Selection of Radio Frequency Technology Solution

Based on the evaluation process discussed above, we selected a balance of technological maturity and the technology solution's ability to leverage our existing communications infrastructure assets. Other technological solutions, such as power line carrier and other RF solutions, have some appeal but are not yet proven at the required scale, are still in the developmental stages, do not possess the data transmission capabilities, or are not available within the timeframe required by the Commission's business case parameters.[1]

The RF technology selected for the business case analysis had the greatest amount of flexibility and scalability given the various deployment strategies under consideration in this proceeding. In addition, this RF technology leverages our existing communications and metering systems. Our distribution system currently has a network of approximately 30,000 radio devices already installed and operational that are used for distribution management and interval metering purposes. From the vendors' responses, we understand that this solution has the ability to provide some level of protection against data loss generally meets the functional requirements of the RFI and is capable of reaching 90 percent of our customers. It also appears to reduce project costs and complexity in comparison to other solutions.

The selected business case technology will require that we replace all residential and small commercial meters with new solid state meters. Using a different RF technology that would allow retrofitting of a subset of existing meters was not found to be a more favorable alternative, given that retrofitting adds to the complexity of an already aggressive deployment schedule without providing any real cost advantage. Based on our experience in attempting to retrofit existing meters for the AMR program, we learned that retrofitting adds

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[1] For example, we recently attempted to test several metering solutions, but learned that some promised components are still under development and may be as many as 12-18 months away from delivery for testing purposes.

substantial complexity and operational cost, including retrofit compatibility issues, higher incidences of failures, and additional handling requirements. Based on the cost estimates for both solutions, we found there was no significant economic benefit to a retrofit solution compared to simply replacing all meters with new solid state technology and leveraging our existing RF network assets.

The AMI technology solution selected for the business case analysis uses two RF technologies; one for residential meters and commercial meters less than 20 kW and one for greater than 20 kW meters. Meters using the first RF technology will be equipped with a radio that communicates with a "collector" to form a Local Area Network (LAN). The collectors will be mounted in the power space of a utility pole or streetlight and will typically communicate with meters within a 400 to 700 meter distance.[2] The greater than 20 kW meters will be equipped with radios under the meter cover and will communicate directly with the network. The two RF technologies are illustrated in Figure B-1.

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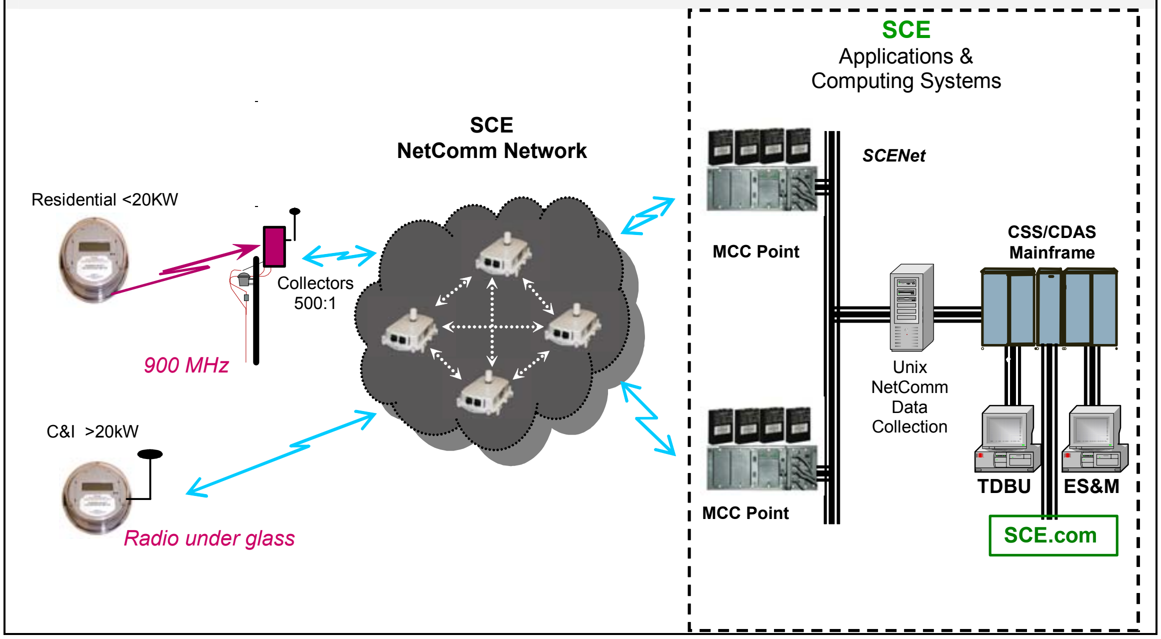
[2] Where a utility pole or streetlight is unavailable, such as in communities with extensive undergrounding of utility equipment, the collectors would have to be placed elsewhere, such as on an easement or leased site.

Figure B-1
Illustration of Selected RF Technology



The Wide Area Network (WAN) is made up of the existing network, the addition of new radio devices, and the 20 kW and above meters equipped with radios. Each end-device radio generates a "packet" of data that travels the network by "hopping" from radio to radio in the direction of the destination-addressed radio. The route chosen for traveling the network is dynamic and employs an automatic rerouting system. This system automatically minimizes the amount of "hops" between the radios, which increases the transmission speed of the data packets. The packet is "addressed" to the communication controller take out point. Each point is connected to the SCE network.

The RF technology uses two distinct types of radio transmission spectrum technology to collect and send meter data. The residential and less than 20 kW commercial meters use a "direct sequence" spectrum technology. This technology typically provides a range of up to 0.5 miles from the meter to the collection device. The technology is one-way, from the meter to the collector. The 20 kW and above commercial meters use a "frequency hopping" spectrum technology in a license-free area of the radio spectrum. This technology provides a range of up to 5 miles. The technology will be deployed in two ways. In some cases, it will be under-the-cover of the meter, typically mounted at approximately five feet high. In other cases, it will be within the collection device normally mounted at a height of 20 to 30 feet. This technology is also peer-to-peer[3] and provides an unlimited number of "data hops." This system is designed to be able to maintain high levels of reliability.

The selected RF technology meets the Ruling's functional requirements among the alternatives considered. This same technological solution would be used for a partial case scenario, but scaled down in size to the targeted geographical area. The details of how this was scaled down are provided in the business case scenario analysis described in Volume 3.

C. AMI Technology Failure

Our technology solution uses solid state metering with electronic components. Throughout the course of the AMI deployment and thereafter, the solid state meters and associated communications infrastructure will experience some level of failure. This failure can be attributed to the actual hardware components failing and/or technology related (*i.e.,* RF) interference impeding meter data communications. These failures will likely result in a required field visit to the meter location to attempt to identify the source of the problem and may require additional investigation. Hardware failures may include one or more of the solid state meter components, the RF communications module, and/or the "collector" device, all of which comprise the LAN communications infrastructure. Hardware failures may be attributed to one of multiple causes, including manufacturer design flaws, defective material provided by other third party manufacturers or vendors (components used to build the meters and communications equipment), and/or defects in workmanship related to the assembly and construction of these components.

Based on our experience with testing new meter technology and with other solid state meter remote communication deployments, it is expected that a higher "meter" failure rate

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[3] Peer-to-peer involves data transmission from house to house or premise to premise.

(AMI technology failure rate of the LAN components) will be experienced than the level of failures associated with our existing mechanical meters. We experienced a high level of equipment failures in our recent RTEM and SPP deployment due to communications and hardware problems.

Over a three-year period, from 2001 through 2004, we purchased approximately 16,000 remotely communicating interval meters. The meters were used in both the RTEM and the SPP projects. The remote communication technologies deployed for these projects included wireless pagers, wireless radios (RF technology), and/or wired phone lines. Since initial deployment in 2001, approximately 48 percent of the 16,000 meter population has been returned for warranty repair. Meter recalls due to design or material defects accounted for 66 percent of these failures. The remaining 34 percent can be attributed to a combination of various material and workmanship related issues. These combined problems translate to an overall average annual failure rate of 16 percent for our RTEM meters throughout this time period.

For the AMI preliminary business case analysis submitted in January 2005, we assumed a lower failure rate than that observed in our RTEM experience. Even though the rapid and wide-scale deployment envisioned under the full deployment scenarios, combined with potential competition for limited metering hardware may cause a higher incidence of product-related problems, we used an estimated failure rate that decreases over time. Our estimated failure rate is higher in the early deployment years, continuously declining until a steady state is reached in the fifth year of the five-year deployment. The average annual failure rate projected over the entire static meter population for the business case analysis is approximately two percent. The impacts from these failures will affect multiple organizations including our Customer Communications, Billing, FSMRO, and Electrical Metering Services organizations.

D. Staging and Development of Applications

The July 21, 2004 Ruling's required five-year meter deployment schedule is aggressive and thus, would require that much of the communications infrastructure deployment and development of IT applications occur simultaneously. As a first priority, we would plan to focus on developing support applications for our supply chain management and meter installation work flow management functions that would necessarily need to be operational before any meter deployment could take place. In order to deploy AMI meters beginning in 2006, we would need to start developing these applications beginning early in 2005. All other remaining applications necessary to support AMI would start being developed in 2006 and would not be operational until mid 2007. The communications infrastructure would start being deployed in 2006 and would not be operational until mid 2007 as well. Deployment of the infrastructure will continue to fill in any coverage gaps identified during the remainder of the five-year period to achieve the 90 percent coverage.

Appendix C

Demand Response Approach and Assumptions

APPENDIX C

DEMAND RESPONSE APPROACH AND ASSUMPTIONS

A. Demand Response Approach and Assumptions

In this Appendix, we describe our approach and key assumptions for estimating demand response benefits from time-differentiated rates (TDRs) enabled by AMI. We followed the guidelines provided by the July21, 2004, and November 24, 2004 Rulings including the framework for demand response scenarios, prescribed assumptions and demand response benefit categories. Our January 12, 2005 preliminary filing presented our approach and results for all required scenarios. This analysis relies on the same general methodology for the best full and best partial deployment cases, but updates certain assumptions from newly available data.

This section is divided into four subsections. First, we describe the key factors and assumptions which support our demand response benefit analyses. In the second subsection, we provide an analysis of the effect of 1-in-10 weather on demand response benefits. In the third subsection, we describe our analysis of the impact on total annual energy use for each scenario. In the fourth subsection, we explain our analysis of the cost-effectiveness of enabling technology based on Summer 2004 results in the Statewide Pricing Pilot (SPP).

1. Key Factors and Assumptions in Estimating Demand Response Benefits

Demand response benefits are driven by four key factors:

- Rate Design and Bill Impact Assumptions - Rate design and bill impacts drive both customer adoption and customers' responsiveness to TDRs.
- Customer adoption of TDRs - Customer adoption in our best-case scenarios was based on opt-out enrollment assumptions provided by the July 21, 2004 Ruling. Customer enrollment in a dynamic rate was a necessary condition for assuming price responsiveness.

- Customer responsiveness to TDRs – The SPP provided observed measurements of customer behavior to dynamic pricing. This provided the basis for estimating demand response of SCE customers under business case scenario-specific assumptions. Adjustments were made to account for SCE customer-specific characteristics, statistical modeling variance and probability, and enrollment methods.
- Value of demand response - Load reductions as a result of TDRs can provide avoided resource value.

Each of these factors is addressed in turn below.

a) Rate Design and Bill Impact Assumptions

Consistent with the July 21, 2004 Ruling, TDRs used in the AMI business case scenarios for residential, small commercial, and medium commercial/industrial customers were designed to be revenue neutral to their respective otherwise applicable tariff (OAT). For each rate class, rates were designed with TOU periods consistent with existing or experimental CPP rate structures. The design structures are summarized in Table C-1 below and the process we used to analyze our proposed rate design and bill impact analysis is discussed in detail in Appendix K.

Table C-1 Experimental/Existing CPP Rate Structures			
	RES	GS-1	GS-2
Existing CPP Tariff =>	TOU-D-CPPF	TOU-GS-1-CPPV	GS-2-TOU-CPP
On-Peak/CPP Event =>	S/W: 2pm-7pm	S/W: Noon-6pm	S: Noon-6pm
Season-Months =>	S/W - 6/6	S/W – 4/8	S/W - 4/8
Rate Structure =>	S/W: On/Off	S/W: On/Off	S: On/Mid/Off W: Mid/Off
	Proposed AMI CPP Rate Structures		
	RES	GS-1	GS-2
On-Peak/CPP Event =>	S/W: 2pm-7pm	S/W: Noon-6pm	S/W: Noon-6pm
Season-Months =>	S/W - 6/6	S/W – 4/8	S/W - 4/8
Rate Structure =>	S/W: On/Off	S/W: On/Off	S: On/Mid/Off W: Mid/Off

Under CPP-F, residential customers are subjected to 5 hours per daily CPP event between the 14:00 and 19:00 hours. Commercial customers under CPP-V are subjected to three hours per CPP event day, between the 12:00 and 18:00 hours. Using 2003 annual rate group load data, CPP “events” were defined with 100 percent certainty to occur on the system peak demand days. This is an unlikely scenario, but we did not make adjustments in rates to account for this level of uncertainty. Uncertainties of this type are more appropriately included as a de-rating factor associated with the value of the demand response. Reducing the value of the demand response, and hence the CPP rate, could be an appropriate refinement but we did not make that adjustment because it would only serve to reduce the demand reduction associated with a lower CPP rate.

CPP “adders” were based on an $85/kW-year capacity cost divided by the number of hours subject to the CPP-F peak period prices. CPP peak rates for rate schedules with fewer hours were capped at the CPP-F levels as they already exhibited a fairly high ratio relative to their otherwise applicable summer on-peak rate (6:1 in the case of non-AB1-X compliant CPP-F residential rates).

In addition to the above longer-term non-AB1X environment described above, an additional short-term AB1X environment analysis is also contained in Appendix K. In that scenario, the net impacts of financing capital cost additions and net operational cost impacts are included in the rate group bill impacts.

CPP rates and bill impacts were used in calculating demand response and customer acceptance of TDRs. The CPP rate was used to estimate peak load impacts. The bill impacts were used in the Momentum Market Intelligence (MMI) model of customer adoption of TDRs.

b) Approach to Estimating Customer Adoption of TDRs

Customer adoption of Critical Peak Pricing over the study period is difficult to estimate because no utility has implemented such rates over a long period of time. For analysis purposes, we used sustained adoption rates required by the July 21, 2004 Ruling for Opt-out (default tariff) enrollments of 80 percent. We assumed that customers who opt-out of the default rate were assigned an adoption rate in equal proportions to other tariff alternatives. For example, in Scenario 4, we assumed that 80 percent of eligible customers default to a CPP-F rate and assumed that 10 percent opt-into a TOU rate and 10 percent opt-into their current rate.

For large customers (>200kW) we assumed that all customers were placed on a two-part RTP rate on a mandatory basis. In Scenario 12, we assumed that all large customers are placed on a two-part RTP rate. In Scenario 13, we assumed that customers currently on Schedule I-6 would stay on that program and all others are placed on a two-part RTP rate. Our analysis of demand response impacts from two-part RTP (*i.e.,* Scenarios 12 and 13) is discussed in Appendix I.

Our customer adoption rates assumed for the business case scenarios in this filing are shown in Tables C-2, C-3 and C-4 below.

Table C-2
Residential Customer Tariff Adoption Rates by Business Case Scenario

Scenario	Default Tariff	Other Tariffs	Full or Partial Deploy-ment	TOU	CPP-F	Current
4	CPP-F	TOU or Current	Full	10%	**80%**	10%
17	CPP-F	TOU or Current	Partial	10%	**80%**	10%

The percentages in bold indicate assumptions required by the Ruling. Percentages are of total residential meters.

Table C-3
GS-1 C&I Customer Tariff Adoption Rates by Business Case Scenario

Scenario	Default Tariff	Other Tariffs	Full or Partial Deploy-ment	TOU	CPP-V	Current
4	CPP-V	TOU or Current	Full	10%	**80%**	10%
17	CPP-V	TOU or Current	Partial	10%	**80%**	10%

The percentages in **bold** indicate assumptions required by the Ruling. Percentages are of the total of C&I customers meters.

Table C-4
GS-2 C&I Customer Tariff Adoption Rates by Business Case Scenario

Scenario	Default Tariff	Other Tariffs	Full or Partial Deploy-ment	TOU	CPP-V	Current
4	CPP-V	TOU or Current	Full	10%	**80%**	10%
17	CPP-V	TOU or Current	Partial	10%	**80%**	10%

The percentages in **bold** indicate assumptions required by the Ruling. Percentages are of the total of C&I customers meters.

There are several reasons for a high level of uncertainty regarding long-term adoption of TDRs. First, there is only very limited experience with customer acceptance of CPP-type rates in the residential class. CPP rates have not been implemented in a mass market, other than pilots, in the United States and thus, customers are generally unfamiliar with such rates.[4]

Second, more than 40 percent of customers surveyed by SCE preferred a tiered or flat rate over time-differentiated rates.[5] While about 30 percent of customers' initial preference was a time-of-use rate, the initial preference for CPP rates was less than 10 percent.[6] It is unknown whether initial preferences predict actual enrollment either in the short run or on a sustained basis.

Third, the utilities had difficulty recruiting customers for participation in the SPP experiment. To meet minimum enrollment targets for the experiment, the utilities had to contact customers individually by telephone to get their agreement to participate in the SPP.

Fourth, the results of market research conducted in the SPP concerning the adoption of TDRs varied widely depending upon expected bill savings and customer awareness of the rate options available to them.[7]

The assumption that 80 percent of customers will indefinitely remain on CPP rates required by the Ruling also requires an assumption about customer awareness of their rate options. The research conducted in the SPP found that an initial enrollment of 80

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[4] Customers are generally familiar with peak/off peak time-of-use rates in the communications industry. However, CPP rates differ in that only certain days, when called by the utility, have very high rates. Customer notification is important and customer understanding of and reaction to that notification, good or bad, has not been examined outside of the SPP experiment where customers received incentives to participate in the program.

[5] Flexo Hiner & Partners, Inc., Final Report, February 11, 2003.

[6] *Id.*

[7] Momentum Market Intelligence, A Market Assessment of Time-Differentiated Rates Among Residential Customers in California, December 2003. See Chapter 5.

percent in CPP-F as a default rate could be reached under an assumption that only 60 percent of customers are aware of their rate options.[8] This research found that increased awareness of rate options (*e.g.*, above 60 percent) would lower the adoption of TDRs on an opt-out or default enrollment basis.[9] Over time, as customer awareness grows, adoption rates would decline, according to that research. Sustaining enrollment would be difficult. Even the CPP treatment group in the SPP that was offered financial incentives to continue to on the program in 2004 had an attrition rate of four to six percent in 2003.[10]

While CPP rates may have appeal to policy makers because high prices can elicit more demand responsiveness, customers have shown little interest in them so far. Only very few large SCE customers have signed up for the voluntary CPP tariff since it was offered in December 2003. The primary barriers to large customer participation are: 1) the effect on customer products or productivity; 2) the level of on-peak prices or non-performance penalties; 3) the relatively small amount of potential bill savings; and 4) the perceived inability to reduce peak loads.[11] Recently, the Commission concluded that voluntary CPP rates for large customers have not yielded what was expected.

> "When interval meters were installed, and voluntary critical peak pricing tariffs were put in place, we expected that the customers with these meters would provide a significant source of demand response capability. Instead, what we have found is that few customers have enrolled in the voluntary critical peak pricing tariffs."[12]

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8 Momentum Market Intelligence. Customer Preferences Market Research, A Market Assessment of Time-Differentiated Rates among Residential Customers in California, December 2003, Table 5-3 p. 109.

9 *Id*. P. 106

10 Monthly Report on Statewide Pricing Pilot to California Public Utilities Commission and California Energy Commission, Exhibit B, January 15, 2004.

11 WG2 Evaluation Update – Market Survey Results, Quantum Consulting, Inc. and Summit Blue Consulting Inc., July 13, 2004, p. 16.

12 Assigned Commissioner and Administrative Law Judge's Ruling Directing the Filing of Rate Design Proposal for Large Customers, December 8, 2004, R.02-06-001.

Our market research found that only 9 percent preferred CPP rates and 29 percent of customers preferred TOU rates in a SCE market research study.[13] This is similar to the SPP market research that found that the CPP-F pilot rate would yield an opt-in market share of 10 percent if 30 percent of customers had awareness of their rate options, 17 percent enrollment with 50 percent awareness, and 34 percent enrollment with 100 percent awareness.[14]

Because the market research indicates that the vast majority of customers do not prefer CPP rates, a CPP program could create a customer backlash if implemented on a default or mandatory basis. The repeal of the Puget Sound Energy's (PSE) short-lived TOU rate program is an example of what can happen when customers become dissatisfied with TDRs. When PSE provided quarterly report cards to customers showing them how much they did or did not save on their TOU rate program, many customers realized that they saved very little or even paid more on the new rate and became upset and opted out of the program. This initially resulted in a public relations problem and ultimately led to PSE's decision to cancel the program.[15]

With respect to the number of customers eligible to enroll in TDRs, we assume that all customers equipped with AMI meters would be eligible, including customers eligible for CARE rates. We ignored the legislative requirements of AB1X, as directed by Agency Staff in Working Group 3.

To sustain the 80 percent customer adoption for CPP over the study period, marketing efforts are necessary to make up for lost enrollments due to premise moving, customer dissatisfaction or customer choice of other options. We anticipate that the

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[13] Flexo Hiner & Partners, Inc., Final Report, February 11, 2003.

[14] Momentum Market Intelligence, "Customer Preferences Market Research, A Market Assessment of Time-Differentiated Rates Among Residential Customers in California," December 2003, p. 98.

[15] Williamson, Craig, "Primen Perspective: Puget Sound Energy and Residential Time-of-Use Rates – What Happened?," Energy Use Series, Volume 1, Issue 10, December 2002, p. 4.

drop-off rate per year would be significant due to higher costs, lack of savings, customer dissatisfaction or moving. Even the SPP participants who were offered an incentive payment to continue to participate in 2004 after 2003 had an attrition rate of four percent.[16]

c) Approach to Estimating Customer Response to TDRs

Our approach to estimating the amount of customer response to TDRs is based on: (1) statistically significant peak load impact results of the SPP for 2003 and 2004,[17] (2) adjustment of the SPP-measured load impact to SCE's territory, (3) adjustment for statistical model variance, and (4) differences in customer response behavior between the TDR enrollment approach in the SPP and the assumed enrollment approach in the business cases. For the first point, we relied on peak load rate impact results for the all-summer period from the SPP based on summer 2003 and 2004 data. On the second point, we used Charles River Associates Inc.'s (CRA) method and analytical simulation model to adjust SPP results for SCE's customer characteristics and service territory weather. On the third point, we adjusted the demand response estimated from the statistical models, using the standard errors produced from the modeling, to obtain an estimate of the 95 percent confidence interval. For the last point, we adjusted the average per customer demand response resulting from the previous steps to account for the fact that the average customer who is defaulted to the CPP rate under an opt-out enrollment will not behave in the same way as the customers who affirmatively opted-in to the SPP experiment. We describe this approach for each of these points further below.

(1) Use of SPP Load Impact Results in the Business Case Scenarios

The SPP consultant, CRA measured the observed residential customers' response to CPP-F, TOU and CPP-V rates and small C&I customers' response to

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[16] Charles River Associates, Inc., Impact Evaluation of the California Statewide Pricing Pilot, Final Report (DRAFT), February 11, 2005, p. 25. A total of 4% of customers elected to opt-out of the experiment between July 1 and October 31, 2003.

[17] *Id.*

the CPP-V rates. Based on the consultant's findings, only the CPP-F results for residential were directly applicable to the business cases. For CPP-V rates, we used a CPP-F proxy. For other tariffs we used the following proxies as described below:

(a) TOU Rates:

SPP results were inconclusive for customers on TOU rates as explained in the consultant's final report: "In short, there are reasons for taking the analysis of the TOU rate treatment with a 'grain of salt.'" Indeed, an argument could be made that the non-CPP day elasticities from the CPP-F treatment would be better predictors of the influence of TOU rates on energy demand than are the TOU price elasticity estimates."[18] Accordingly, we used the non-CPP day time of use elasticities for our analysis.

(b) CPP-V for Commercial Customers:

SPP results were inconclusive because the treatment samples were relatively small and not representative of the C&I population as a whole. As a proxy, we used a price elasticity for C&I that is 25 percent of the residential price elasticity found in the SPP. This estimate is supported by current literature.

(c) CPP-Pure for Residential and Commercial Customers:

This rate was not tested in the SPP. In our preliminary studies, we used the price elasticity for CPP-F as a proxy. CRA supports this proxy assumption. This rate was not used in our best scenarios described in this filing.

(d) Two-part RTP for Large Customers:

Two-part RTP rate was investigated in WG 2 and no conclusions or guidance on how a rate could be designed were provided. We therefore used the literature to develop an approach to large customer response to a two-part RTP. This approach is described in Appendix I to this volume.

[18] *Id.* , p. 91.

(2) Application of SPP Statewide Results to SCE Territory

There are two key components of estimating the demand response from TDRs in SCE's territory: (1) the existing energy use by rate period for customers in the target population prior to the introduction of a new rate, and (2) price elasticities, which are used to predict the change in energy use by rate period. Our approach to developing each of these components is described below.

(a) Existing Energy Use

We estimated the existing average energy use of SCE customers by climate zone and rate period for residential, GS-1 and GS-2 customers from our load research data. The average energy use was based on summer 2003 data, which is a reasonable proxy for the "average" summer for SCE. Our average energy use assumptions are shown in Table C-5 below.

Table C-5
Existing Average Energy Use by Class and SCE Climate Zone (kWh/hr)

Rate Group	SPP Climate	CPP Day		Non-CPP Week Day		Summer Week Day		Weekend/ Holiday
	Zone	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak	
Residential	2	0.67	0.53	0.63	0.50	0.64	0.50	0.55
	3	1.63	0.91	1.28	0.79	1.31	0.80	0.96
	4	1.73	1.02	1.44	0.89	1.47	0.90	1.08
GS-1	All	2.29	1.26	2.14	1.22	2.17	1.22	1.08
GS-2 < 200 kW	All	27.01	16.62	25.52	16.06	25.78	16.16	18.56

(b) Price Elasticities

The price elasticity econometric models were developed by CRA using statewide observations in the SPP for 2003 and 2004. Two summary measures of price response used in this analysis are the elasticity of substitution and the daily price elasticity of demand. As described above, the elasticities used in the analysis are based on the SPP results for CPP-F rates. The SPP elasticity data for all of California are found in Table 4-10 of the CRA February 11, 2005 report and are summarized in Table C-6 below for SCE climate zones.

Table C-6
Residential CPP-F Rate Elasticity Estimates Statewide
All Summer Averages

Climate Zone	**Elasticity of Substitution**		**Daily Price Elasticity**		
	CPP Days	Non-CPP Days	CPP Days	Non-CPP Days	Weekend Days
2	-.061	-.055	-.042	-.044	-.018
3	-.102	-.093	-.043	-.047	-.026
4	-.113	-.105	-.032	-.039	-.020

To determine price elasticities for SCE, we made adjustments based on the weather conditions (*see* Table C-7) and the central air conditioning (CAC) saturations representative of SCE populations in our Climate Zones 2, 3, and 4 (*see* Table C-8).

Table C-7
Cooling Degree Hours by Zone and Period for Normal Year

Climate Zone	**CPP Day**		**Non-CPP Day**		**Average Summer Day**	
	Peak	**Off Peak**	**Peak**	**Off Peak**	**Peak**	**Off Peak**
2	10.39	1.90	1.83	0.17	2.60	0.31
3	21.60	5.59	8.13	1.24	9.45	1.63
4	27.16	12.44	15.95	5.88	17.02	6.47

Table C-8 SCE Central Air Conditioning Saturations	
Climate Zone	**CAC Saturation (Percent)**
2	21.2
3	57.81
4	60.89
All	41.91

With the guidance from the SPP consultants, CRA, and the PRISM load reduction simulation tool, we derived load reductions for customers in our territory by making adjustments for air conditioning saturation and cooling degree hours.[19] The impact estimates for residential CPP-F and TOU TDRs are shown in Table C-9 below. As noted above, we used the impact estimates on peak for CPP-F as the proxy for CPP-V (for C&I customers equals the impact for residential times 25 percent) and the impact estimates on peak on non-CPP days for TOU.

[19] The Price Response Impact Simulation Model (PRISM) prepared by CRA and provided to SCE for use on February 11, 2005.

Table C-9 Peak Period Impact Estimates for SCE Specific Residential Tariffs Based on All Summer SPP Results					
Climate Zone	**Impact Measure**	**CPP-F Rate**		**TOU Rate**	
		CPP Day Peak	**Non-CPP Day Peak**	**CPP Day Peak**	**Non-CPP Day Peak**
Zone 2	**Change (kWh/hr)**	-0.107	-0.019	-0.019	-0.019
	% Change	-16.01	-3.09	-2.78	-2.78
Zone 3	**Change (kWh/hr)**	-0.362	-0.069	-.069	-.069
	% Change	-22.21	-5.40	-5.81	-5.81
Zone 4	**Change (kWh/hr)**	-0.366	-0.085	-0.085	-0.085
	% Change	-21.17	-5.90	-7.79	-7.79

(c) Adjustment to SPP Load Impacts for Statistical Model Variances

The issue of how much forecasted load reduction could be counted as a load modifier for resource adequacy purposes has not been determined by the Commission. For purposes of this analysis, we have taken statistically significant price elasticity estimates and applied average energy usage, average weather and average air conditioning saturation data particular to SCE to derive estimated load impacts from TDRs. We suggest that an additional statistical analysis is required to determine what load impact result from the SPP for SCE customers can be reasonably relied upon at a 95 percent confidence level.

The load pricing impacts were estimated using the CRA spreadsheet model, which applies the Elasticity of Substitution (ES) model parameters to CAC saturations and weather data for the SCE service territory. Two elasticity values are calculated, each based on three model parameters and the weather and saturation data.

These elasticity parameters are then applied to customer usage and price data for SCE's customers to arrive at the load impact during on-peak hours for each climate zone. Because these load impacts are estimates based on statistical modeling, there is uncertainty in these estimates. While there can be uncertainty from various sources, our analysis focused on the uncertainty due to the model estimation process. We did not attempt, in this step, to account for uncertainty from other sources.

The variance observed in this analysis is the variance of the average customer response. The response from any individual customer will be much more variable. Because we are looking at the total load impact (which depends on the average customer response), we are not including the individual customer load impact variability in this analysis. CRA's PRISM models included the standard errors and t-statistics by zone for all variables that were necessary to do this analysis.

We used Monte Carlo simulation to estimate the distribution of the load impacts. The simulation program (Crystal Ball) generates many replicates of a set of random variables, and then evaluates a formula based on those replicates to get a distribution of the result of the formula. Using this approach, we developed an approximate distribution for the load impact results for each climate zone. Using this approximate distribution, we also determined a one-sided 95 percent confidence interval on the load response.

The results of our Monte Carlo analysis for capacity planning in each zone are shown in Table C-10 below.

Table C-10
CPP-F Peak Load Impact at 95th Percentile

Zone	PRISM Peak kW/kWh Impact	95th Percentile Peak kW/kWh Impact
2	-.1073	-.0996
3	-.3620	-.3387
4	-.3662	-.3313

(d) Customer Behavior Adjustment for Opt-out Default Enrollment Scenarios

A critical assumption in the analysis of demand response benefits is the expected response of the population who default onto the CPP-F rate. We do not have empirical data on which to base this assumption. The SPP provided measurements of participant response to TDRs in the Impact Evaluation of the California Statewide Pricing Pilot, Final Report, prepared by CRA.[20] However, the response measured in the experiment was of customers who adopted the CPP-F rate on a *voluntary and affirmative enrollment basis*.

Importantly, this method of enrollment would likely yield average customer behavior to TDRs that is very different than customers who are enrolled by default. SPP participants were unique in that they were heavily recruited, fully informed of the rate options under the pilot, affirmatively opted-in to a rate and were paid an incentive for participation. Even under these special conditions, only a small percent of those customers initially contacted agreed to participate in the experiment. Opt-out or default enrollments result in a portion of customers who default on a rate unless they affirmatively opt out to another rate. The opt-out or default method can result in high enrollments because customer knowledge and understanding of their rate choice is not necessary. In fact, the SPP research found that high enrollments were consistent with relatively low customer awareness of rate choices under opt-out enrollment.[21] Differences in behavior between opt-in and default enrolled customers would be due to differences in interest in participation and understanding/awareness of rate options.

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[20] Statewide Pilot Project, Summer 2003 Impact Analysis Impact Evaluation of the California Statewide Pricing Pilot, Final Report, Charles River Associates, August 9, 2004February 11, 2005, (Draft).

[21] *Id.*, Momentum Market Intelligence.

Customer awareness of rate options is important because it is a key factor in price responsiveness. If the customer is not aware of the rate or price, the customer will not respond. Undoubtedly, "unaware" customers would not take affirmative steps to reduce load at peak periods in the same way as "aware" customers. SPP participants, due to the recruitment process and the affirmative actions they made to enroll in the experiment should be assumed to have full awareness of the CPP-F rate and their options. Their education and awareness in the enrollment process prepared them to respond when prices were high during CPP events.[22]

To quantify the appropriate response of all customers on the CPP-F rate at peak under an opt-out scenario, we must adjust for these customers who default to the rate unknowingly. We made this adjustment first by assigning the full portion of the SPP measured peak load reduction from the CPP-F rate to the portion of customers in a business case scenario who we estimate would have affirmatively opted-in to the CPP-F rate. Then, for the remaining portion of customers assumed to default to the CPP rate, we assigned a lower percentage of the peak load reduction measured in the SPP from the CPP-F rate. Essentially, we believe that customer responsiveness under an opt-out enrollment process is a function of customer awareness of and interest in their rate.

The way we derived the customer responsiveness for opt-out enrollment is described as follows: Scenario 4 assumes that 80 percent of eligible residential customers enroll on the CPP-F rate on a default basis. Using the MMI model developed from the SPP, we determined that about 16.8 percent of SCE's residential customers would have affirmatively opted-in to the CPP rate if it were offered on that basis. For discussion purposes, we called this group "willing enrollments" on the CPP-F rate. Thus, the remaining 63.2 percent (80-16.8) must be customers who would not opt-out of the CPP-F rate due to inertia, perception of risk, are unaware or would not understand their rate options. In

[22] A summary of the measures to recruit and inform customers is provided in CRA's Final Impact Evaluation of the Statewide Pricing Pilot, July 2003-December 2004, pp. 23-25.

essence, the 63.2 percent group are "default enrollments" but are assumed on the CPP-F rate nonetheless. The load impact from the "default enrollments" was not tested in the SPP or any other experiment and is unknown. The MMI work in the SPP project demonstrates that to achieve an eighty percent enrollment on an opt-out basis about half of those enrolled would be unaware of their rate options. Using this data implies that 50 percent or more of the "default" enrollments would not respond to CPP events due to a lack of awareness or understanding of the price signal.

We used a weighting factor to determine an average load impact to apply to all customers on an opt-out enrollment of CPP-F rates. For willing enrollments, we applied 100 percent of the SPP observed load reductions at the 95 percent confidence interval (*see* Table C-10 above). For the default enrollments, we applied 50 percent of the load reductions observed in Table C-10. Accordingly, on a weighted basis, we apply a 60.5 percent factor to the full SPP load impact for CPP-F on a per-customer basis for the entire population assumed to be on the CPP-F rate in Scenario 4, as shown in the table below. We applied the approach in the above example in Scenarios 4 and 17.

Table C-11
Load Impact Adjustment for Scenario 4 Using SPP Results for Summer 2003

	Percent of Eligible Customers Enrolled of Total Population	Percent of Customers with CPP-F Rate	Factor of SPP Load Impact	Weighted Factor of SPP Load Impact Applied to CPP-F Customers
Willing (Opt-in) Enrollments	16.8	21	100 %	0.21
Default Enrollments	63.2	79	50 %	0.395
Total	80	100		0.605

The adjusted percentage load impact per customer on CPP-F rates resulting from the adjustment for opt-out enrollment and is shown in the table below.

For the Peak load reductions for the CPP-F rate on CPP days, we include the adjustment for estimating load reduction at a 95 percent confidence level (described above) because these estimates are used to determine avoided generation capacity savings, which is the bulk of the estimated demand response benefits.

Table C-12
Adjusted Residential Peak Period Load Impact from TDRs for SCE Assuming Opt-out Enrollment (Percent Reduction)

Climate Zone	CPP-F Rate	
	CPP Day	Non-CPP Day
2	8.99*	1.64
3	12.57*	3.08
4	11.58*	3.38

* Includes adjustment for 95 % confidence described above.

d) Resource Value

For all the required scenarios, the July 21, 2004 Ruling assigned a capacity value of $85/kW-yr, and energy value of $63/MWh and a congestion avoidance value of $7/MWh. We applied these estimates in all scenarios to comply with the July 21, 2004 Ruling. However, we do not believe that $85/kW-yr is the correct value to use in this analysis. Rather, we make "value adjustments" to account certain operational restrictions attributed to CPP, and uncertainties in market forecasts for supply availability and load. Our value adjustments are described in Appendix D in this volume. In sum, the July 21, 2004 Ruling's assumption for capacity at $85/kW-yr to reflect avoided reserves of 15 percent results in a value of $97.75/kW-yr. With our adjustments, we believe that the value of load reductions from CPP-F rates should be $52.70/kW-yr, which includes 15 percent for avoided reserves.

2. One-in-Ten Year Weather Analysis

As required by the July 21, 2004 Ruling, we prepared an analysis of the effect of 1-in-10 year weather on demand response benefits. Although it is interesting to note the effect of a hot year on demand response however, an average weather year is more appropriate for the business case.

We used 1997 as representative of a one-in-ten weather year based on population-weighted cooling degree hours. That year had higher overall energy use in Climate Zones 2 and 3, and lower energy use in Zone 4 than for the average year. As a result, the demand response benefits increase for Zones 2 and 3 and decrease in Zone 4. In total, the benefits for Scenario 4 increase due to the 1-in-10 year weather analysis. Scenario 17, however, only includes the population of Zone 4. Due to the lower energy usage and cooling degree hours in Zone 4 during 1-in-10 year weather, the demand response benefits are decreased for Scenario 17 from the average weather analysis. The results are shown in Table C-13 below. Supporting data are provided in Tables C-14 and C-15 below.

Table C-13
1-in-10 Year Weather Adjustment Results to Total Demand Response Benefits
PV $2004, in Millions

Scenario	Average Weather Analysis	1-in-10 Weather Analysis	Difference
4	$366.7	$403.5	$36.8
17	$42.9	$35.0	($7.9)

Table C-14
Cooling Degree Hours by Zone and Period for 1-in-10 Year

Climate Zone	CPP Day		Non-CPP Day		Average Summer Day	
	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak
2	13.01	3.39	3.50	0.52	3.98	0.67
3	22.82	7.23	9.94	1.63	10.59	1.95
4	23.41	10.31	15.93	5.47	16.50	5.80

Table C-15 1-in-10 Year Energy Use by Class and SCE Climate Zone (kWh/hr)								
Rate Group	**SPP Climate**	**CPP Day**		**Non-CPP Week Day**		**Summer Week Day**		**Weekend/ Holiday**
	Zone	**Peak**	**Off Peak**	**Peak**	**Off Peak**	**Peak**	**Off Peak**	
Residential	**2**	0.92	0.68	.67	0.56	.70	.57	0.60
	3	1.90	1.06	1.12	0.73	1.19	.76	0.84
	4	1.48	0.87	1.05	0.67	1.09	.69	0.80
GS-1	**All**	2.47	1.33	2.18	1.20	2.22	1.22	1.03
GS-2 < 200 kW	**All**	27.19	17.86	25.09	16.57	25.36	16.73	14.15

3. Impact on Total Annual Energy Use

The November 24, 2004 Ruling directed SCE to answer the following question – "In other words, does the tariff structure assumed result in overall reduced energy usage (conservation impact), shift of load (no overall impact), or increased energy usage?"[23]

To perform this analysis, we used the results from the CRA all-summer PRISM model and results from the CRA all-winter PRISM model, as adjusted for SCE territory and assumed responsiveness. As described in the summer analysis, Non-CPP day CPP-F results were used as a proxy for TOU rates. We provide the results of this analysis for a single year after full deployment in 2012. The results of the analysis provided in the table below shows that there would be an increase in total energy use in each scenario. To put this increase in perspective, for Scenario 4, the increase would be about 0.01 percent of total SCE customer consumption.

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[23] Assigned Commissioner and Administrative Law Judge's Ruling Calling for a Technical Conference to Begin Development of a Reference Design, Delaying Filing Date of Utility Advanced Metering Infrastructure Applications, and Directing the Filing of Rate Design Proposals for Large Customers, November 24, 2004, R.02-06-001, p. 4.

Table C-16 Impact on Annual Energy Use (kWh/yr) by Tariff and by Class for 2010				
	Scenario 4		Scenario 17	
	CPP-F	TOU	CPP-F	TOU
Residential	11,187,500	-990,486	3,859,873	254,770
GS-1 (<200kW)	-245,701	-48,655	143,782	11,053
GS-2 (<200kW)	-687,367	-141,880	381,490	29,071
Total	10,254,432	-1,181,020	4,385,144	294,894
Grand Total	**9,073,412**		**4,680,038**	

4. Cost-Effectiveness of Enabling Technology Combined with CPP Rates

In our preliminary business case analyses, we included Scenario 7 which provided the costs and benefits of demand response plus reliability case using a default CPP enrollment plus enabling technology. Our approach in Scenario 7 was to deploy our Advanced Load Control (ALC) smart thermostat technology to a portion of customers not on CPP rates. We used this approach because there was a lack of representative data from the 2003 SPP on the cost and load impact results of customers on CPP rates with enabling technology. We also did not know how many customers would adopt enabling technologies without incentive payments. While those studies provided a reliability component of demand response benefits, the ALC deployment is considered as a decision separate from AMI because we have included ALC is in our business-as-usual case (*see* Appendix G).

For this business case analysis, we used the SPP results for Summer 2004 that provide sample data on two key issues not provided in the Summer 2003 results. With those results, we were able to determine that a scenario assuming CPP coupled with an offering of enabling technology was not more cost effective than our Scenario 4. This analysis is explained below.

The Summer 2004 SPP study provided data on two issues with respect to enabling technologies. First, the study provided an estimate of customer acceptance of enabling technology combined with a CPP rate. A sample of customers from Track A in the SPP was offered a choice whether or not to accept enabling technology, free of charge. About

30 percent of the customers accepted the installation of a Smart Thermostat. No incentives were paid to the customer for allowing the utility to control the thermostat. The second key data provided by the SPP was the demand response of customers in Track A with enabling technology. The demand reduction impact of enabling technology is found in the 2004 data.

We used the assumptions for Scenario 4 where 80 percent of residential customers default to the CPP-F rate. To determine the penetration of enabling technology in this scenario, we applied the 30 percent acceptance rate for enabling technology to the percent of customers who would opt-in to the CPP-F rate. As discussed above, that percentage is 16.8 of residential customers. This yields about five percent of customers on CPP-F rates with the enabling technology and 75 percent of customers on CPP-F without enabling technology. For the cost of enabling technology, we assumed the costs for our ALC smart thermostat (smart thermostat $95 and installation $98.25/unit). Finally, we relied on the SPP Summer 2004 results for Track A customers with enabling technology as the expected demand reduction for that group of customers. The overall result of the scenario with enabling technology was about $36 million in net present value worse than Scenario 4. This is not entirely surprising because the demand response benefit of enabling technology relies on the same load reduction source as the CPP rate at peak. The benefit of the net increase in load reduction derived from enabling technology does not overcome the added cost of the smart thermostat plus installation.

Appendix D

Avoided Procurement Cost Value Assumptions

APPENDIX D

AVOIDED COST VALUE ASSUMPTIONS

A. Summary of CPP Analysis Methodology

This Appendix describes our approach in evaluating the economic generation benefits of demand reductions induced by Critical Peak Pricing (CPP) in the final AMI business case analysis. The approach uses avoided cost principles (marginal energy and capacity) as the value proxy for generation benefits and also incorporates "value adjustments" (both positive and negative) to account for reserve margin benefits, certain operational restrictions attributed to CPP, and uncertainties in market forecasts for supply availability and load. This methodology was used in combination with the Commission-assigned estimates of avoided capacity and energy values to analyze the economic benefits of demand reductions resulting from CPP. We believe the end result is a more accurate and mathematically-sound assessment of the economic value of demand reductions caused by CPP to our customers.

B. An Avoided Cost Approach Was Used To Value The Generation Benefits of CPP

Characteristically, demand response programs derive most (~90 percent or more) of their generation-related value from avoided capacity costs rather than avoided energy costs.[24] Limited-event demand response programs or tariffs, such as CPP, are designed to help mitigate peak load requirements for short durations, not unlike a peaking resource. Such limited-event resources provide opportunities to displace higher-cost energy only when triggered. However, CPP can displace the need for a capacity resource (*i.e.*, combustion turbine) during those periods, which can result in significantly more value than the potential for energy displacement.

For the two required business case scenarios, we assigned a capacity value of $85 per kW-yr, an energy value of $63 per MWh, and a congestion avoidance value of $7 per MWh

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[24] Other potential benefits may exist which are not discussed here, such as O&M savings.

consistent with the July 21, 2004 Ruling.[25] Both the energy and capacity values are assumed to be "at the generator" level and levelized over a 15-year period assuming a utility discount rate.

The Commission has a long-standing policy of using a combustion turbine (CT or peaker) proxy method for estimating the marginal value of capacity and a system marginal energy cost for estimating the marginal value of energy.[26] The Commission's view of $85 per kW-yr is nearly the same as our view of marginal capacity value, which is based on the real economic carrying charge methodology[27] of a CT. Similarly, the Commission's view of $70 per MWh[28] is nearly the same as our marginal energy cost estimates for the highest peak periods when CPP would be triggered. This estimate is based on our adopted 2004 Long-Term Procurement Plan (LTPP),[29] with updated assumptions for gas prices, loads and resources to better reflect more recent forecasts.

1. Crediting Capacity Value to CPP

Capacity is generally defined as the right to call on the production of energy, and is analogous to financial call options. It is important to note that capacity only has value if it can be called upon for energy or defers the need for energy. This is a fundamental principle in both electricity and financial markets. In financial markets, a call option's value is derived

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[25] Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure (Ruling), July 21, 2004, Appendix B.

[26] For economic valuation purposes, the value of capacity is never higher than the cost of a CT since any greater capital investment would be justified by lower energy costs. This concept is known as Energy Related Capital Costs ("ERCC").

[27] Also referred to as the rental value or deferral value method. We will be updating our view of marginal capacity value in Phase 2 of our General Rate Case (GRC) A.04-12-014 to be submitted in May 2005, consistent with the real economic carrying charge methodology, as we have done in previous GRC filings.

[28] $63 per MWh energy + $7 per MWh congestion charges.

[29] The LTPP was found reasonable and adopted by the Commission on December 16, 2004 in Decision (D.) 04-12-048, subject to modifications that do not significantly affect the need, timing or cost effectiveness analysis of CPP. The baseline assumptions of the LTPP were designed around the overall intent and "loading order" of the joint agency Energy Action Plan, including significant increases in cost effective energy efficiency and demand response programs and meeting the 20 percent Renewable Portfolio Standard by 2010.

from the option holder's right to exercise the option. In electricity markets, the hourly energy requirement of a load serving entity (LSE) is based on its ability to call upon firm capacity resources, whether contracted or directly owned. These capacity resources are in effect "call options" in which the LSE decides from hour to hour whether to exercise these capacity resources for energy. If a particular capacity resource is unable to provide energy when the call option on the energy is exercised,[30] then the value of the resource's capacity to the LSE is zero for the period it was unavailable. This is a common performance-based attribute of how capacity payments are made by LSEs to generation owners.

Demand response programs, generally, cannot be called upon more often than a specified number of strikes (calls) on an annual and daily basis. In the case of CPP modeled in our analysis, this tariff is limited to twelve calls per summer period, and each call cannot exceed a continuous five hours in duration. CPP can effectively be exercised no more than sixty hours per year (12 events per year × 5 hours per event). In contrast to a combustion turbine, which can be called upon up to 8,760 hours in a year, the CPP program is a much less available resource and therefore has less capacity value.[31] However, having lower capacity value benefits does not mean a program is not cost effective; the investment costs of a demand-response program may be lower than that of a CT (on a per kW basis), making the demand-response program more cost-effective by comparison.[32] In order to properly evaluate any difference in capacity value, we must understand the way in which capacity value is allocated across time.

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[30] Possibly due to an outage, other physical limitation such as exceeding environmental or startup limits.

[31] This attribute is also true of limited energy resources such as wind generation.

[32] In the case of AMI, where the decision on making a long-term investment in costly metering infrastructure hinges on demand response benefits, the relative value of CPP (including metering infrastructure costs) as a resource compared to other resources is paramount.

2. Time Differentiating Capacity Value

Both marginal energy and capacity values are time differentiated. Energy costs vary according to daily gas prices and hourly system incremental heat rates. Gas prices and heat rates are typically higher during peak demand periods, therefore differentiating energy value across time. Likewise, capacity value varies according to need and the relative risk of low reserve margin events. Periods of supply shortages during system contingencies (unanticipated or anticipated) tend to increase the value of capacity, therefore differentiating capacity value across time.

The marginal capacity value provided by the Commission ($85 per kW-yr) is an annualized value and not yet differentiated by time. Thus, we have "spread" or allocated the annual marginal capacity value using relative loss of load probability (LOLP) values to indicate time differentiated values based on peak period usage.[33] LOLP is a measure of system reliability that indicates the ability (or inability) to deliver energy to the load. A more detailed description is provided in the next section.

a) Loss of Load Probability

There is always some probability, however small, that the electricity system will be unable to serve demand. The risk of a generation shortage can be reduced by over supplying generation, but over investment and high operating costs would significantly increase customer bills. Determining the optimum supply and demand balance requires the study of expected system operations using a probabilistic risk assessment approach. Analysis of a system's LOLP is an appropriate risk assessment approach – it is a measure of system reliability that indicates the ability (or inability) to deliver energy to the load.

The LOLP metric provides a method for allocating annualized capacity value across time-of-use periods in proportion to when the loss of load is likely to occur.[34] For

[33] This approach is a standard utility practice and has been used in prior SCE GRC proceedings.

[34] The purpose of this LOLP analysis is not to forecast the precise timing of future low-reserve margin events, nor is it to forecast the absolute magnitude of any single loss-of-load event. Rather, it is intended to be a relative distribution of risk used to allocate capacity value across time.

example, if the LOLP is greatest in the summer period primarily due to load conditions, particularly during the on-peak, then most of the value we would attribute to capacity will be assigned to those periods. On the other hand, if the probability for loss-of-load is essentially zero during winter off-peak periods, we would assign very little capacity value at those times. LOLP makes it possible to evaluate the relative reliability contribution of different resources across a range of time-of-use periods.

We used Henwood's MarketSym model and the "Medium Load Plan Scenario" from our adopted 2004 LTPP[35] as the basis to calculate a probabilistic estimate of the fraction of time that the SCE system is unable to meet demand. Our analysis employed a Monte Carlo approach by way of two-factor mean reversion sampling of loads and resources. The analysis performed 250 simulations of the entire Western Electricity Coordinating Council (WECC), each unique with regard to hourly supply and demand. From the Monte Carlo analysis, we were able to extract hourly resource availability and loads from each of the 250 simulations. An LOLP event occurs in hour *h* when the load (*L*) exceeds available resources (*R*).

$$L_h - R_h > 0$$

For each simulation, the load in a particular hour can be compared to each of the 250 Monte Carlo outcomes of resource availability in that same hour. In other words, the load in hour *h* is assumed to have the same likelihood of occurring in any of the 250 resource outcomes in hour *h*. The same is true from another viewpoint: the resource availability in hour *h* is assumed to have the same likelihood of occurring in any of the 250 load outcomes in hour *h*. Effectively, this approach yields 250 × 250 or 62,500 possible combinations of load and resources in hour *h*. The above equation can be modified to illustrate this method.

$$L_{h,\,i} - R_{h,\,j} > 0$$

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[35] *See* footnote 6, *supra.*

Where i and j are from the respective simulations for load and resources. The range of loads and resources is determined by stochastic parameters tied to historical performance.

Each load and resource combination is given equal probability of occurring assuming short-term variations in loads (*i.e.*, weather) and available resources (*i.e.*, forced outages) are purely random. Combinations in which available resources are unable to meet the load (hence, loss-of-load) contribute to the LOLP for that hour. For example, if 125 out of the 62,500 combinations resulted in loads exceeding available resources, then the LOLP for that hour is 0.2 percent (125 divided by 62,500), or a probability of 1 in 500.

The hourly LOLPs, or stochastic LOLPs, are normalized over all hours of the year such that the sum of the normalized LOLPs equals 1. This effectively creates a relative relationship of the hourly LOLP across time.

The stochastic LOLP approach takes into account as much uncertainty as can reasonably be captured within the limitations of the model. These are the same uncertainties facing today's system operators (load forecast, supply availability, and hydro conditions). We believe this approach provides a reasonable representation of estimating the relative risk of not serving the load in any given hour, realizing that not all of the market's inefficiencies can be captured in any single model.

3. Incorporating Necessary Value Adjustments to The Avoided Cost Approach

Generally, the capacity value (Vc) of a supply- or demand-side resource is equal to the expected deliverable capacity (EDC) of that resource multiplied by the avoided cost of capacity (AC).

$$Vc = EDC \times AC$$

For the purposes of analyzing CPP, the AC (measured in \$/kW-yr) is based on the July 21, 2004 Ruling's value of \$85 per kW-yr. The EDC is the kW quantity expected to be reliably available and deliverable to the load.[36] For example, if a supply-side resource has a nameplate rating of 100 MW, but after considering expected delivery limitations due to congestion, losses and the environment,[37] it may actually only deliver 80 MW of electricity to the grid. It would be inappropriate to give 100 MW "capacity credit" to this resource if only 80 percent of it is expected to be deliverable. The same is true for demand-response programs, such as CPP, where customer participation based on historical response results will likely reduce the program's nominal rating to a more realistic level.

However, the above equation does not consider certain attributes associated with a demand response program that will affect the value of capacity. The equation will require an adjustment factor to account for the reduced need to procure planning reserves (adding value), and two adjustment factors to account for operational restrictions (subtracting value), all of which are discussed below.

Unlike a supply-side resource, a demand response program reduces an LSE's resource requirement. In effect, this reduces the need to procure additional reserves to meet the load.[38] Therefore, the value of a demand response program should include the value of capacity associated with procuring for a planning reserve margin (*PRM*) requirement.[39]

$$Vc = EDC \times AC \times (1 + PRM)$$

In the above equation, it is important to make the distinction between capacity that can be used to serve the load and capacity that meets resource adequacy requirements. In other words, only 100 percent of the *EDC* can actually be used to serve the load, but 115 percent of the *EDC* can be applied to meet resource adequacy requirements. This distinction

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[36] Both the *AC* and *EDC* values need to be at the same delivery level, *i.e.*, at generator, at ISO-interface, or at the customer level. For the purposes of this analysis, the *Vc* inputs are evaluated at the generator level.

[37] For example, opacity limitations.

[38] For every MW of expected load reduction due to demand-side management, 1.15 MW of capacity procurement is avoided, assuming a 15% planning reserve margin (*PRM*) as directed by the Commission in D.04-10-035, Conclusions of Law No. 4.

[39] *Id.*

is necessary when we later consider the operation limitations of CPP, which will only apply to the *EDC* portion that is dispatchable. Thus, the equation can be algebraically expanded to make this distinction:

$$Vc = (EDC \times AC) + (EDC \times AC \times PRM)$$

The CPP program is a limited energy resource, meaning, it can only be exercised for a limited number of hours per year. Specifically, CPP can be called 12 times a year for five hours each, and only during the summer months. As discussed earlier, capacity only has value if it can be called upon for energy or defers the need for energy. The dispatch limitations of CPP will reduce its value of capacity relative to a CT proxy, which is available year-round. To account for this reduction in value, the prior equation should apply an adjustment factor (*A*) to the dispatchable *EDC* portion:

$$Vc = (A \times EDC \times AC) + (EDC \times AC \times PRM)$$

Where the *A*-factor is less than or equal to 1.

The avoided cost of capacity (*AC*) assigned by the Commission is assumed to be based on a CT proxy, which is a day-of call option[40] for power. Some demand response programs, such as CPP, are designed to be (one) day-ahead options. Generally speaking, a day-of call option has more intrinsic value than a day-ahead call option by virtue of the former having greater flexibility in time of need. To credit the full value of capacity as defined by a CT proxy to a day-ahead program would not be a fair evaluation and will overstate its value. Therefore, the equation should be modified to reflect this adjustment in capacity value with a factor (*B*).

$$Vc = (A \times EDC \times AC \times AC) + (EDC \times AC \times PRM)$$

Where the *B*-factor is less than or equal to 1. For a demand response program that can be dispatched day-of, the *B*-factor by default equals 1.

Finally, the equation can be algebraically modified in its final form as:

[40] The capacity from a CT proxy can be used for energy with one hour notice.

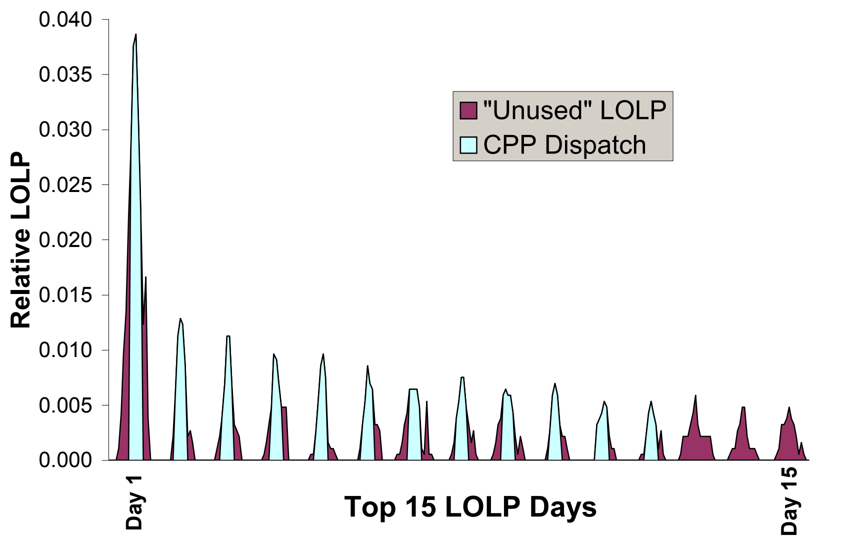
$$Vc = EDC \times AC \times (A \times B + PRM)$$

a) The *A*-Factor

The *A*-factor is determined by simulating an optimal dispatch of the CPP program against an LOLP forecast, and calculating the percentage of time the program is able to "displace" LOLP events, subject to the program's dispatch limitations. As discussed earlier, the LOLP forecast is a method of allocating capacity value across time. To the extent the CPP program can be available during times of need (as defined by the LOLP forecast), it will be credited capacity value during those times. In the optimal dispatch simulation, the CPP program is assumed to be called upon as often as allowed during periods of greatest LOLP. The following figure illustrates the highest LOLP hours over the top 15 days. Each daily LOLP extends for several hours within the day, ranging between 11 AM and 9 PM. Although the CPP program is optimally dispatched, the five-hour window is not enough to capture all LOLP hours in each day. Furthermore, since the CPP program is limited to 12 calls per year, it does not capture LOLP events beyond the 12th day.[41]

[41] Ninety-five percent of the total LOLP occurs over the span of 29 days.

Figure D-2



This analysis results in an *A*-factor of 50.2 percent. The *A*-factor can be increased in three ways: 1) increase the number of allowable events per year beyond twelve; 2) extend the duration of each event to more than five hours; or 3) allow the program to be called during non-summer months.

b) The *B*-Factor

The *B*-factor is based on the difference in value between a day-ahead and a day-of call option for power. A CT is essentially a day-of call option with a strike price equal to the variable operating cost of a CT proxy. The CT proxy value should be adjusted downward for demand response programs that are callable on a day-ahead basis. The CPP program, for instance, is a day-ahead call option resource. For a demand response program that can be dispatched on a day-of basis, the *B*-factor equals 1 by default.[42]

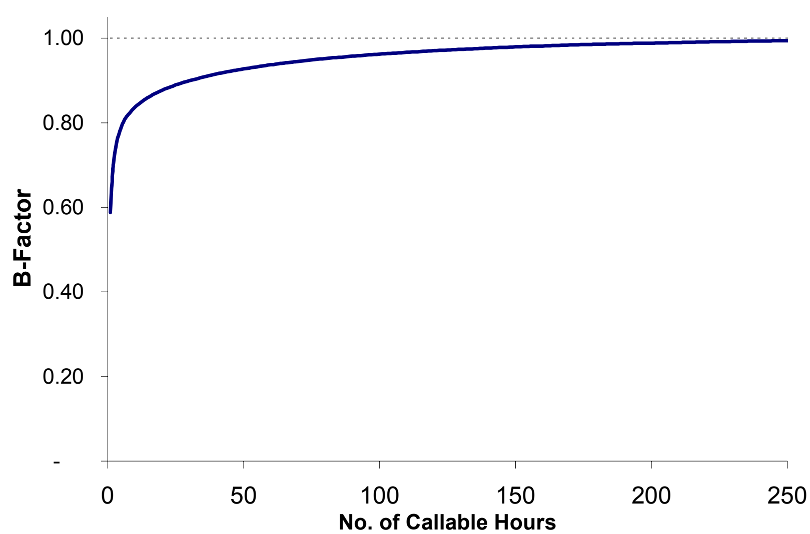
One approximate method to capture the difference in value between a day-ahead and a day-of program is to compare the value of a day-ahead and day-of call option

[42] If the notification time for a day-of CPP program is greater than the time between dispatching a CT and receiving energy, then the value of the *B*-factor is less than 1.

resulting from a Black-Scholes option model.[43] The Black-Scholes model is a standard tool for valuing energy options, but can be used to estimate the relative "payoff" of demand response resource options with differing times to expiration (time horizon). Inputs to the model are the forward view of LOLP, day-ahead and day-of volatility of LOLP, and time to expire. The output of the model is a relative value of each call option. Comparing model outputs for day-ahead volatility inputs versus day-of volatility inputs provides a relationship that can be used to approximate the relative value of a day-ahead versus a day-of demand response program.

For a day-ahead demand response program,[44] the *B*-factor is represented in the Figure below.

Figure D-3



The value of a day-ahead call option approaches the same value of a day-of call option if the day-ahead option has sufficient callable events. A demand response program that is dispatchable for 300+ hours will likely capture all of the LOLP events in a year, regardless of whether the program has a day-ahead or day-of dispatch requirement.

[43] John C. Hull, 3rd Edition, p. 393.

[44] The *B*-factor only applies to demand response programs with a zero strike price.

In the case of CPP, which is dispatchable up to 60 hours per year, the *B*-factor is 0.937.

c) CPP Capacity Value Results

Given the following:

$$Vc = EDC \times AC \times (A \times B + PRM)$$

$$\begin{aligned} &where \\ &\quad A = 0.502 \\ &\quad B = 0.937 \\ &\quad PRM = 0.15 \end{aligned}$$

$$Vc = EDC \times AC \times 0.62$$

Or, the value of capacity (*Vc*) credited to CPP is 62 percent of the full deferral value of a CT proxy. Based on this analysis, the value of capacity at the generator from the CPP program is \$52.7/kW-yr, as shown below:

$$Vc = EDC \times \$85/\text{kW-yr} \times 0.62$$

$$Vc = EDC \times \$52.7/\text{kW-yr}$$

To compute the benefit of the CPP program at the customer level, a distribution loss factor must be applied to the avoided capacity benefit at the generator.

Appendix E

Uncertainty/Monte Carlo Analysis Assumptions

APPENDIX E

UNCERTAINTY/MONTE CARLO ANALYSIS ASSUMPTIONS

A. Monte Carlo Analysis of Demand Response Benefits

Consistent with the July 21, 2004 and November 24, 2004 Rulings, we applied a Monte Carlo simulation approach to the demand response benefit calculation for each scenario. For the opt-out enrollment scenarios, we distinguish customer response between "willing enrollments" and "default enrollments," as explained in Appendix C. For the Monte Carlo analysis, we varied the customer behavior characteristic of default enrollments from a mean of 50 percent of the load impact of the SPP experiment to 33 percent on the low side and 67 percent on the high side.

In addition, we applied a derated value of demand response (CPP-F tariff) resources, as described in Appendix C. For this Monte Carlo analysis, we assumed a distribution of plus or minus 10 percent around our estimated value of $52.70 kW-yr.

We employed a standard software application, Crystal Ball, to run a Monte Carlo simulation across the range of the above variables. Our alternative results for the DR-1 capacity and energy benefit for Scenario 4 are shown in Table E-1 below.

Table E-1
Monte Carlo Analysis of Demand Response Benefits (DR1 Only)
(PV $2004, in Millions)

	Scenario 4		**Scenario 17**	
	W/O losses	Including Avoided Losses	W/O losses	Including Avoided Losses
SCE Low	$181	$196	$21	$23
SCE High	$211	$229	$24	$26
SCE Expected Value	$193	$209	$23	$25

Appendix F

Financial Assumptions

APPENDIX F

FINANCIAL ASSUMPTIONS

Our key financial assumptions to develop the cost and benefit information used in our business case analysis for Scenarios 4 and 17 are discussed below.

A. Labor Costs

All of our labor estimates are based on annualized Full Time Equivalent (FTE) employee requirements. Non-represented labor costs were determined by the SCE Market Reference Point for specific job titles. Represented labor costs were determined by our current labor contract for the appropriate job title. Pensions and benefits costs for health care, pension, and benefit plans were determined using marginal costs and escalation rates that are consistent with SCE's 2006 General Rate Case. Installation and meter-handling labor is allocated sixty percent to installation of new meters, and forty percent to removal of old meters. Where required, severance costs were estimated by our Human Resources Department using existing severance plans and policies. Severance is contemplated for certain positions under the full deployment scenario, while some positions will be reduced solely through attrition. Where additional facilities are required for added workers, incremental facility costs for field personnel, Customer Communications, and Billing staff were estimated using market lease rates for the specific required facilities.

B. Capital Costs

Capital costs for AMI meters include meters, installation labor, direct supervisory costs, and related vehicle, material, and supply costs. Tax depreciation for cash flow purposes is based on relevant Internal Revenue Service rules. Capital costs of replacing any devices (*i.e.,* servers, computers, meter batteries), whose useful lives expire between 2006 and 2020 are included in the analysis. Although significant capital replacements for meters, communications equipment and IT hardware would be scheduled to occur in 2021, costs for these replacements were excluded from our analysis.[45] The estimated net salvage value of $1.00 per meter has been credited against removal expense. Unrecovered capital costs at the end of 2021 are not included in the revised preliminary analysis, but would be recovered over future periods.[46]

C. Taxes

For cash flow purposes, we used tax rates of 35 percent for federal and 8.84 percent for state. Tax benefits from early write-off of the removed meters are included in the cash flow and revenue requirement analysis.

D. Cost of External Financing

The July 21, 2004 Ruling requires the utilities to evaluate various financing options for the large capital expenditure anticipated for a full deployment of AMI. Specifically, the July 21, 2004 Ruling required the utilities to evaluate both an internal financing/implementation approach as well as an outsourcing approach in which AMI acquisition, installation, and O&M would be obtained under contractual arrangements with third-party providers.[47]

Any large contractual obligation on the part of SCE has a detrimental impact on SCE's credit rating. For any outsourcing arrangement where we are the counterparty, such as contracting to pay a third-party for 15 years for meter installation/ownership or for meter O&M, rating agencies equate the capital lease with a debt instrument. Thus, in addition to cost of the cash payments to the third-party, capital leases appear on our balance sheet and must be offset by adding equity to the capital structure. Importantly, as was discussed in the outsourcing business case scenarios contained in our revised preliminary business case analysis submitted on January 12, 2005, none of the potential AMI outsource providers

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[45] *See* "Uncertainty and Risk Analysis" in Sections IV and V of Volume 3.

[46] Unrecovered capital costs in 2021 were estimated to be approximately $19 million and $190 million for the partial and full deployment scenarios, respectively.

[47] *See* July 21, 2004 Ruling, Attachment A, pp. 4, 8.

demonstrated the ability to provide superior financing terms above our own, notwithstanding the capital lease issue.

E. Net Present Value Analysis and Assumptions

As detailed in Volume 3, all operating costs and benefits were estimated in 2004 dollars, and then escalated to nominal (year-incurred) dollars. Annual nominal cash flows were then summarized and discounted back to 2004 dollars using Excel's "NPV" function, with a 10.5 percent discount rate. All references in these volumes to "2004 NPV" or "2004 Present Value" use this approach. Demand Response benefits were analyzed using the levelized capacity and energy values specified in the July 21, 2004 Ruling.

We present our NPV analysis under two approaches. Under the first approach, we calculated the NPV of each scenario using a standard discounted cash flow approach. Each year's nominal costs and benefits were summarized along with their tax impacts,[48] to produce an after-tax cash flow NPV.

The revenue requirement analysis utilized the same nominal costs and benefits, but used regulatory (or "book") depreciable lives for capital assets and included the carrying costs of new capital investments. It also incorporated the rate impact of the accelerated recovery of the existing meters, which would be removed in an AMI deployment.

The after-tax cash flow analysis demonstrates that, on a financial basis, projects with negative NPVs are a poor use of capital. The revenue requirement analysis demonstrates whether a project will have a beneficial or negative impact on customer rates.

To calculate the annualized or monthly revenue requirement impact, the annual revenue requirements for each scenario were discounted back to a 2004 present value and were then levelized over the 2006 – 2021 analysis period.

48 Higher O&M costs and depreciation would provide a tax deduction, while demand response benefits and O&M savings produced higher taxes.

F. Revenue Requirement Analysis and Assumptions

Revenue requirement impacts, including both the operating expenses and capital costs associated with AMI implementation, were assessed. We estimated net AMI-related revenue requirement impacts for the two scenarios for years 2006 through 2021. These estimates, which are detailed in Appendix K, were determined by subtracting expected revenue requirement reductions from estimated AMI-related revenue requirement. Revenue requirement reductions include cost savings from Customer Service-related O&M reductions, existing meter revenue requirements reductions and procurement cost reductions. AMI-related revenue requirement includes: 1) anticipated O&M expenses and capital costs associated with expected rate base amounts for new AMI-related meters and related infrastructure; and 2) stranded costs associated with the undepreciated balance of existing or replaced meters, which we propose to amortize over the five-year new meter deployment period. We estimate for Scenario 4, that the total project NPV revenue requirement increase would be $952 million, or $125 million annually. For Scenario 17, we estimate that the total project NPV revenue requirement increase would be $130 million, or $17 million annually. These results are discussed in detail in Volume 3. These revenue requirement impacts were assessed for business case analysis purposes only.

G. Treatment of Costs Not Clearly Anticipated by the July Ruling

1. Pre-2006 Start-up Costs

The July Ruling mandates a "2006 to 2021 analysis period,"[49] but in order to meet the five-year deployment target, some costs would have to be spent in 2005 to prepare for a 2006 rollout. These pre-2006 costs have been included in the business case scenarios as 2006 costs.

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[49] Ruling, Attachment A, p. 12.

2. Early Retirement of Meters

To implement AMI, all existing meters that do not meet the communication and interval data capabilities required by the July Ruling would have to be replaced, even though those meters that still have much of their useful life left. As of June 2004, we have approximately $318 million in undepreciated meter capital, after adjusting for the small percentage of out-of-scope meters in Scenario 4. Accounting rules require SCE to charge the undepreciated balance of the retired meters, along with the cost of their removal (net of salvage value realized) against accumulated depreciation. This total is estimated to be approximately $631 million for Scenario 4. We have incorporated this cost into the business case, as cost code "MS-9 Salvage/Disposal process for removed meters." These costs will need to be recovered contemporaneously with the system installation through an appropriate cost recovery mechanism.

Appendix G

Business As Usual Case

APPENDIX G

BUSINESS AS USUAL CASE

A. Overarching Approach

The Business As Usual case, as described in the July 21, 2004 Ruling, is to serve as the "base case," or reference point from which to compare the relative costs and benefits of the full and partial AMI deployment scenarios. This case serves three primary purposes: (1) to identify those significant metering and communications investments made that can be leveraged by AMI, and therefore should not be included in the deployment scenarios as new incremental cost; (2) to identify those investments that can be avoided if AMI is deployed; and (3) to identify those investments (*e.g.*, ALC) whose load reduction benefits will be replaced by implementing AMI. For SCE's analysis, we define "Business As Usual" to mean no changes to our metering infrastructure or demand response programs beyond those currently in place or anticipated in the normal course of doing business under existing regulatory standards relating to these matters. Unlike the two AMI deployment scenarios in this analysis, the Business As Usual case is based on actual costs as recorded, and forecast in our 2006 General Rate Case (GRC) proceeding.[50] For the July 21, 2004 Ruling's required analysis period, beyond the time period forecasted in the GRC (*i.e.,* 2009 through 2021), we trended costs based on our experience and judgment. By defining our Business As Usual base case in this manner, we are able to determine all incremental costs that would be incurred solely as a result of AMI deployment, as well as identify which base case costs would be eliminated by AMI.

Although we expect that technology improvements over the next 16 years will likely change today's cost and benefit structure, to facilitate our analysis, our base case assumes that the current operating environment and cost and benefit structure will remain static over

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[50] *See* SCE's 2006 GRC Application (A.04-12-014) filed on December 21, 2004.

the 16-year study period.[51] We will make modifications or adjustments to the base case in order to avoid double counting of costs or benefits where appropriate. For example, full deployment of AMI meters would eliminate the cost of meter purchases that otherwise may occur under the base case. These modifications are described in more detail in the Full and Partial "Business Case Analysis" (Scenarios 4 and 17) in Sections IV and V of Volume 3.

Table G-3 shows the recent history and our forecast of "business as usual" metering capital and O&M expenditures.

Table G-3
Metering O&M and Capital Expenditures
Business As Usual Case ($ Million)

	Recorded					Forecast				
	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Metering O&M	$6.3	$5.4	$4.6	$5.1	$6.2	$7.2	$7.2	$7.4	$7.5	$7.7
Metering Capital	$12.8	$18.8	$12.6	$16.1	$17.6	$20.3	$21.9	$19.2	$19.0	$20.1

B. Existing Advanced Metering and Communications Infrastructure

In the normal course of doing business, we assess the potential for improving operational efficiency and have already implemented advanced metering and communications technologies as previously mandated, as well as automated meter reading (AMR) in those areas where it appears to be operationally efficient and economically beneficial to ratepayers to do so.

[51] Although unlikely, it is necessary to assume costs and benefits will remain static for our purpose here in order to establish the necessary baseline against which the deployment scenarios can be compared.

1. Real Time Energy Metering (RTEM)

We currently have approximately 13,000 RTEM installations which measure 15-minute interval usage data for customers with monthly demands of 200 kW and greater.[52] We also have approximately 700 RTEM units in place for our residential and small commercial customers who participated in the SPP. In addition, we have roughly 10,000 Dynamic Load Profile meters which are used to provide load data for system planning and California Independent System Operator (CAISO) settlement purposes. Data is collected daily from these accounts via paging, telephone, and radio-frequency (RF) communications. Our automatic data collection system makes this data available to our largest customers via the Internet. This data is also used in the monthly billing for our largest accounts and thus, we no longer routinely read these meters manually. Full scale implementation of AMI would essentially eliminate the need for the Dynamic Load Profile metering, given that these meters would be replaced with AMI meters.

2. Automated Meter Reading

We have been a pioneer in mass implementation of AMR, with over 500,000 meters that are currently read using AMR technology. Approximately 360,000 of these meters are installed in our highest cost-to-read routes and are being read by a vendor from a "drive-by" van on a monthly basis. The remaining AMR meters are also high-cost-to-read meters (typically installed because of access problems or meter reader safety issues), scattered throughout our service territory. These meters are read monthly by the meter readers as they "walk-by" these locations on their routine monthly routes. All of our AMR systems utilize meters equipped with encoder/receiver/transmitters (ERTs) which could (theoretically) be paged hourly via a two-way radio network. However, because we are

[52] Pursuant to the December 8, 2004 Assigned Commissioner and Administrative Law Judge's Ruling Directing the Filing of Rate Design Proposals for Large Customers, SCE is moving forward with installations of RTEM meters on the approximately 2,000 customers who do not already have an RTEM. These costs have not been included in this analysis because they are part of the Business As Usual base case.

currently utilizing these systems only for monthly billing purposes, the walk-by, and drive-by data retrieval method is more cost effective.

The AMR program is concentrated in those parts of our service territory where it is most cost effective. We continue to add approximately 20,000 new ERT meters annually as access or safety related problems arise and as we continue to monitor the cost/effectiveness of our existing meter reading routes. Thus, our Business As Usual case includes our estimate of future on-going costs of maintaining AMR and communications technology in today's operating environment.

Under Scenario 4, we have assumed that the entire AMR infrastructure is replaced by AMI. This replacement, on the July 21, 2004 Ruling's mandated deployment schedule, would leave us with an unfulfilled contractual obligation with a vendor for AMR meter reading through 2011. Although these AMR costs would be stranded under AMI deployment, they are reflected in current rates. Thus, we did not make any adjustment to remove these costs from either the full or partial deployment scenarios so that these costs would continue to be recovered. There are no incremental operational savings prior to 2011 that result from re-automating existing AMR meters. To partially mitigate the cost of this fixed commitment, we have assumed the conversion of the AMR routes to AMI would take place late in the AMI implementation schedule, thus obtaining maximum value from the current contract. Avoided cost savings after 2011 would be minimal, since the meters would still need to be read monthly by a vendor or by an SCE meter reader.

3. Advanced Load Control

Air Conditioning Cycling (ACC) systems can and do function effectively, independent of the proposed AMI infrastructure. This is the case with over 124,000 currently-active ACC participants via SCE's existing RF communication systems. In SCE's Long-Term Procurement Plan (LTPP) filed in R.04-04-003, we submitted our proposal to expand and enhance our residential load control program to increase the demand response this program delivers.

Our proposed Advanced Load Control (ALC) Program would result in 500,000 customers participating in load control and providing an estimated peak demand benefit of 700MW. Under our ALC proposal, the cost of ALC devices was estimated to be $138 per residential unit and $130 per unit for installation. Under the AMI deployment scenarios, we assumed that the ALC equipment and installation could be combined with the AMI meter deployment. For the combined deployment, we assumed that the ALC device would be about $95 per residential unit and installation would be $100 per unit.

4. Outage Management System (OMS) and Transformer Load Management (TLM)

We have already invested in developing automated systems to assist us in detecting power outages (through the OMS) and managing load on our transformers (through the TLM system). As described in SCE's 2006 GRC, we continue to improve automation and data communications for its substation operations with Intelligent Electronic Devices (IEDs) that communicate through a Local Area Network to our Supervisory Control and Data Acquisition (SCADA) System.[53] The modern protection and control equipment we are using provides remote, self monitoring control of substation functions, and identifies potential problems to avoid reliability events to which we must respond quickly. Among the many types of automation and sophisticated electronic equipment that we use in our substations and operations network are satellite communications for substation data collection and remote system control in areas where conventional methods of communication are not available or are too costly.

Our existing OMS draws outage information from three different sources: (1) SCADA System, (2) distribution control system (DCMS), and (3) customer trouble tickets from our Customer Services System (CSS). These data are mapped in OMS to computerized

[53] *See* SCE's 2006 GRC Application (A.04-12-014) filed on December 21, 2004, Ex. No. SCE-3, Vol. 3, Part IV.

graphical representations of circuit maps to help dispatch crews to restore service. OMS also has the capability of tracking the repair work to completion.

The AMI system, as proposed, is potentially a fourth data source into OMS. While it may be possible to link individual meter service outage data from the AMI system into OMS, it is not currently practical given that OMS outage identification based on our current mapping capabilities does not extend beyond the structure level on a circuit map. We would not be able to cost-effectively increase the level of outage knowledge beyond that which we currently receive from SCADA, DCMS and the greater than 85 percent of customer calls into our phone center that are currently mapped through OMS.

Because we already have adequately functioning OMS, TLM, and SCADA systems,[54] we already obtain associated benefits in our T&D activities.[55] As such, the potential added value related to outage management, transformer loading, and other T&D benefits that otherwise might accompany AMI for some utilities is virtually nonexistent for SCE. We have not included any incremental costs or benefits of AMI relative to these systems in our full and partial deployment scenarios.

C. Major Expected Investments

We have already developed a significant infrastructure including Information Technology (IT) systems necessary to access, validate, and store mass quantities of interval data. We have also developed the necessary interface with the billing system to perform monthly billing for internal meters. The costs associated with this existing internal metering infrastructure are embedded in our rate base, as part of our historical recorded O&M expenses. These embedded costs are very difficult, if not impossible, to separate from other existing metering embedded costs. For this reason, we have developed the costs and benefits

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[54] *Id.*

[55] However, these systems do not address an individual or small pocket of customer outages as would an AMI system. Usually when an individual or pocket outage occurs, the customer calls us. Because the marginal benefit of automatic notification via a meter to a very small number of customers affected for a short period of time is likely to be insignificant, no value was assigned for this preliminary analysis.

for Scenarios 4 and 17 on an incremental cost basis. This means that all cost and benefit estimates are incremental, over and above those currently included in the Business As Usual case.

1. IT Infrastructure Supporting Billing

Although much of the existing IT infrastructure which supports our RTEM and SPP program can be utilized in the AMI deployment scenarios, the existing IT systems have various design limitations which will hinder our ability to directly leverage these investments. The existing, internal meter data handling and billing interfaces were built to process and store data acquired monthly from thousands of accounts, not hundreds of thousands or even millions of accounts as is anticipated in the partial and full AMI deployment cases. The incremental cost of developing and operating the new and expanded IT systems have been included in the cost estimates of each of the deployment scenarios.

2. Meter Reading Infrastructure

Meter reading cost and benefit estimates for each deployment scenario are incremental when compared to the base case. However, one adjustment was made to the Business As Usual capital budget presented in our 2006 GRC. Full or partial deployment of AMI would eliminate the need for replacement of some of the meter readers' electronic hand-held computers. These devices will be out of warranty in 2007 and would otherwise be replaced due to wear and tear and technical obsolescence.[56] For Scenario 4, the overall costs were reduced by $2.9 million (in 2004 PV dollars), to reflect the avoided cost of replacing these devices. For Scenario 17, the overall costs were reduced by $785,000 (in 2004 PV dollars).

3. Meter Replacement Costs

Metering capital costs include not only the material cost of the meter itself, but also the labor cost of the initial installation and the final removal. For purposes of this

[56] *See* SCE's GRC Application (A.04-012-014) submitted on December 21, 2004, Exhibit No. SCE-4, Vol. 2, Chapter V.

analysis, the labor cost associated with installing approximately 72,000 new meters annually in response to normal customer growth is not expected to change significantly and has been left in the base case. The labor costs are not included in the full or partial scenario as new costs. Material costs on the other hand will be significantly different for the full and partial AMI deployment scenarios. The difference is the estimated incremental material cost of installing interval meters that meet the AMI functional requirements versus the current metering assets.

Each AMI deployment scenario incorporates the estimated cost of purchasing AMI meters for retrofit, replacement, and customer growth, as well as the avoided costs (benefits) of not purchasing electromechanical meters for replacements and customer growth.

Appendix H

Summary of Potential Benefits

APPENDIX H

SUMMARY OF POTENTIAL BENEFITS

All potential benefits identified in the July 21, 2004 Ruling were considered for inclusion in the analysis of the two revised scenarios. Those benefit codes that were actually used have been addressed separately in each scenario analysis. This Appendix includes a discussion of all of the benefit codes identified in the July 21, 2004 Ruling, whether we used them or not. This summary is presented in two sections, Section I addresses the potential benefits as they relate to full deployment Scenario 4, Section II addresses potential benefits as they relate to partial deployment Scenario 17.

D. Summary of Potential Benefits – Full AMI Deployment

1. System Operations Benefits (SB-1 through SB-13)

Appendix A of the July 21, 2004 Ruling identified 13 potential system operations benefits that may result from deployment of AMI. In our review of these potential benefits, we have been able to quantify savings, coming from four of the 13 benefit codes. We expect some net benefit from two other benefit codes, which we are not able to quantify at this time. The remaining seven potential areas of benefit identified in the July 21, 2004 Ruling are either already being experienced by SCE, have associated costs that more than offset the anticipated savings, or otherwise do not apply.[57] The following sections address all 13 of the potential system operations benefits as described in the July 21, 2004 Ruling.

a) (SB-1) Reduction in Meter Readers, Management and Administrative Support (and Associated Costs)

This is the single largest area of operational benefits expected to accrue from AMI. We currently employ approximately 570 meter readers and 80 management and

[57] Several cost codes were found to be duplicative of one another. Where this occurs, we point out the duplicate cost code to avoid double counting.

support personnel, 80 percent of which would be eliminated with full deployment of AMI. As described in Volume 3, full deployment under our "best case" scenario will result in our ability to automatically read 90 percent of all our meters. The remaining 10 percent, or approximately 470,000 meters, will continue to be read monthly by approximately 109 meter readers.[58] In addition, we expect to eliminate 16 of the existing meter reader supervisor positions with full deployment of AMI.[59]

The reduction of 80 percent of our current meter reading organization would result in a total savings of $271 million (expressed in 2004 present value dollars) savings over the duration of the analysis period. With our current attrition rate of 35 to 40 percent annually, the reduction of meter reading personnel is expected to take place through normal attrition during the latter phases of AMI deployment. Attrition is expected to ramp-up beginning with the actual activation of the AMI communications system (approximately 18 months after AMI installations begin) and continue throughout the deployment years. Severance of 32 supervisory personnel will result in a one-time cost of $3 million in 2010 ($1.9 million in 2004 present value dollars). This severance cost is included in cost code MS-1. Additional savings will result from the decommissioning of 80 percent of our hand-held meter reading devices. This savings is reflected in benefit code MB-1.

b) (SB-2) Field Service Savings (Turn-Ons / Turn Offs) And Lower Need For Pickup Reads

SCE currently completes nearly half of its "turn-off" and "turn-on" meter orders without having to actually turn the meter on or off. This situation occurs when a "turn-on" order can be matched to a "turn-off" order for the same location, on or about the

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58 The remaining 10 percent of the meters with which we are unable to communicate are scattered throughout the SCE territory and generally not adjacent to one another, thus making manual meter reading less efficient than it is today. Our assumption is that it will take 20 percent of the existing number of meter readers to read the last 10 percent of meters.

59 These 16 supervisory positions are incremental based on the number of supervisory personnel required today, without AMI. The actual Reduction in Force (RIF) will require severance of 32 supervisors due to the temporary build-up of personnel to deploy AMI.

same day. Such orders can be completed merely by taking a meter read, which currently requires a visit to the site at an average cost of approximately $15 per order. Virtually all of these special meter reads for matched on/off meter orders could be eliminated and replaced with the daily AMI meter read. For the full deployment scenario, this benefit would result in the reduction of approximately 30 FTEs and a savings of approximately $29 million over the duration of the analysis period (*i.e.* through 2021).

c) (SB-3) Reduction in Energy Theft–May Provide Ability to Identify Active Accounts for Metered Accounts Not Being Billed, Broken Meters, Wrong Multipliers

In reviewing this "potential benefit," we were unable to identify any incremental savings that may accrue due to AMI deployment. These situations can be identified by a Meter Reader making an actual observation of the meter installation on a monthly basis. The Meter Reader is our primary means of identifying potential meter tampering and energy theft, especially in those instances where the meter is bypassed or "jumpered" and the integrity of the meter itself is not affected. Although we expect to uncover a number of energy theft situations during the installation phase of AMI that may have otherwise gone undetected, the additional investigators required to resolve these new cases will remain in place after the installation phase in order to complete investigations and make optimum use of information derived from the AMI system to track, monitor and perform ongoing investigations.

Energy consumption on accounts not being billed may be identified more quickly under Scenarios 4 and 17, given that daily reads will be available. This benefit is relatively small and is addressed under "Idle Usage Episodes" in benefit code MB-5 below.

Both energy theft and broken meter situations would be harder–not easier–to identify through AMI, given that physical tampering is not readily apparent through automated meter readings and a zero read does not necessarily indicate a broken meter. Many broken meters continue to register consumption, though it may not be correct.

Rather than identifying any SB-6 benefits, we have actually identified several potential risks related to these collective issues based on today's technology.

d) (SB-4) Phone Center Reduced FTEs in the Long Term Due to Anticipated Lower Customer Call Volume (Estimated / Disputed Bills)

Billing inquiries today are received for several reasons, only one of which is an inaccurate meter read. Based on a study using 2003 data, 22,791 inquiries to the Call Center were a result of meter reading errors. We used this number as a percentage of all calls to determine the percent of calls in subsequent years that would be projected as meter read error calls. For purposes of this analysis, we assume that 100 percent of these calls will be avoided with the full deployment of AMI.

Table H-1 shows the number of avoided calls that may result from the complete elimination of meter reading errors. Using 3,376 as the average number of Billing Inquiry calls answered per FTE in the Billing Inquiry specialty support group during 2003, under full deployment we are estimating a levelized reduction of seven FTEs by 2010, for a total benefit of $3.5 million through 2021.

Table H-1
Reduced Phone Calls

Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Full Deployment	2,820	8,445	14,089	19,753	23,626	23,626

e) (SB-5) Possible Productivity Enhancement / Rate Changes Simplified / Possible Reprogram Rather Than Meter Change

Some currently-installed TOU meters would require re-programming in the field if the Commission ordered a change in the definition of time-of-use on and off-peak time periods, seasonal definitions, holidays, *etc*. This programming limitation does not exist with AMI meters because they record 15-minute and hourly consumption data.

This is a benefit that SCE will already obtain because we are systematically changing our existing TOU meters to electronic interval data recorders. This effort is expected to be completed by the end of 2005.[60] The value of having the ability to more readily apply time differentiated rates to a vast majority of our customers through full AMI deployment is included in the demand response (DR) benefit codes to be described later.

f) (SB-6) Outage Management Benefits

This potential benefit available from today's AMI technology has been addressed in the Business As Usual case in Appendix G as follows: "Because we already have adequately functioning OMS, TLM, and SCADA systems, we already obtain associated benefits in our T&D activities. As such, the potential added value related to outage management, transformer loading, and other T&D benefits that otherwise might accompany AMI for some utilities is virtually nonexistent for SCE. We have not included any incremental costs or benefits of AMI relative to these systems in our full and partial deployment scenarios."[61]

We have identified some savings attributable to the ability to confirm individual service outages when "no-lights" trouble calls are received at the Call Center. This has been quantified and discussed under benefit code CB-2.

g) (SB-7) Better Meter Functionality/Equipment Modernization

The broader range of functionality of new electronic meters, such as those that would be used for AMI, provides advantages over their electro-mechanical predecessors. The most apparent advantage is the universal "one-size-fits-all" capabilities of the modern meter. Although there are still a number of variations in "meter forms," and instrument transformers are still the norm for large accounts, the number of variations is not nearly as broad as it once was. The result is a potential for reduced meter inventories (see benefit code

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[60] SCE's Meter Infrastructure Replacement program is described in SCE's 2006 GRC Application in SCE4 Vol. 2, Chapter V.

[61] *See* Appendix G.

MB-4) and the ability to carry replacements for most meters in field vehicles. Because we are already using RTEM and interval metering for our larger C&I accounts, we are already taking full advantage of this functionality benefit through normal business operations and as captured in the Business As Usual case. This more universal metering functionality is less evident among smaller C&I and residential accounts and is recognized as a qualitative benefit arising from any future AMI deployment.

The incorporation of two-way communications provides the potential for meter diagnostics and voltage verification that do not exist today. AMI meters would also provide the potential means to alert the customers of system peaks and could automatically trigger some form of direct load control. They could also provide a means to allow the customer to access their own metered data for use in reducing consumption during peak periods. These are all recognized as qualitative benefits. However, each of these optional functions carries offsetting costs that are not readily quantifiable at this time. Because incremental costs are not available, we are not able to determine the economics of including any or all of these functional options in this business case analysis.

h) (SB-8) Remote Service Connect/Disconnect

We respond to over 1 million turn-on/turn-off service requests annually, and we disconnect and reconnect nearly 1 million additional meters for credit related, non-payment issues. Nearly one-half of the on/off service requests and all of the credit disconnects require the physical disconnection of service at the customer's meter. AMI meters could be equipped with a remote disconnect switch contained within the meter, which could provide the ability to "remotely" turn electric service on or off.

However, today this is a costly option to be added to an AMI meter as a separate add-on module. A typical 200 amp disconnect switch (not including additional hardware/software necessary to activate) would cost approximately $150 to $200 per meter. By comparison, we currently incur a cost of approximately $17 to respond to a next day on/off service order and approximately $24 for same-day service. Thus, the installation of a remote disconnect switch would only make sense where there is frequent customer turn-over (*i.e.*, student housing, apartment complexes, *etc*.) and/or where credit collection problems exist. Even with turn-over rates of two or three per year at any specific location, the cost effectiveness of this option today is marginal at best. Therefore, we have not included the remote service connect/disconnect functionality in our technology selection, nor have we included any related benefit in any of the AMI deployment scenarios.

i) <u>(SB-9) Meter Accuracy - Improved and More Timely Load Information Could Increase Forecasting Accuracy and Reduce Resource Acquisition Costs and Reduce Customer Complaints About Faulty Meter Reads</u>

A new solid state meter is slightly more accurate over the full range of its rated load capability than its electro-mechanical predecessor. A cost savings has been estimated for reduced call volume relating to billing inquiries as described in SB-4 above. On the other hand, the potential for increased initial failure rates for current AMI technology (as was the case with RTEM meters) has been identified as a potential risk and results in significant cost increases in the Billing Organization due to increased meter order and exception processing (see cost codes CU-1, CU-4, and I-11).

Because customer load information would be available in a more timely manner (*i.e.,* hourly, daily, weekly, *etc*.), it will provide some benefit to SCE with regard to forecasting accuracy and in reducing resource acquisition costs. These costs savings have been identified in Scenario 4 where our Energy Supply and Marketing Organization has included interval data collection and processing costs of $2.3 million (cost code M-15) and forecasting benefits of $3.3 million as part of their on-going operations over the duration of the analysis period.

Benefits derived from improved “billing accuracy” are discussed below under benefit code CB-1.

j) (SB-10) System Planning Design Efficiency – Savings from More Accurate Information on Status of Transformers And Distribution Lines Etc.

In theory, AMI would give us the opportunity to aggregate coincident customer loads within any specific area in order to determine the demand on a distribution circuit or an individual distribution transformer. In reality, however, distribution circuit loads are dynamic and cannot be assumed to be confined to any geographic area over any extended period of time. This is because sections of load are constantly being switched from one circuit to another (and from one transformer to another) during circuit interruptions, for routine maintenance, and for load balancing purposes. Because of this constant state of change, at any given time we are able to match only 80 to 85 percent of our customers with their serving transformer. SCE already has a Transformer Load Management program in place that already provides this information for distribution planning purposes (see benefit code SB-6). As such, we do not expect deployment of today's AMI technology to create any incremental benefits in this area.

k) (SB-11) Reduction in Unaccounted for Energy (UFE)

As described above, AMI could theoretically give us the opportunity to aggregate customer loads within any specific geographic area in order to determine the demand on any particular distribution circuit. Even if this were technically feasible, it is not clear how this aggregated load information will assist in identifying the source of UFE.

We currently have the ability to analytically model system losses using customer load profile data compared to total system generation, and have concluded that the amount of UFE is not significant enough to warrant any further investigation of the sort suggested as a potential benefit under full AMI deployment.

The "watts lost" rating of an electronic meter is typically greater than that of the single phase electro-magnetic meter it would be replacing. We estimate the average AMI meter would be rated at approximately one watt higher than their single phase electro-mechanical counterparts. Taken on its own, this technical characteristic of electronic meters would add four megawatts of UFE load, 24 hours a day, 365 days per year. This would add over 35 million kWh per year in energy consumption.[62]

l) (SB-12) Ability to Monitor Customer Self-Generation Into System on a Real Time Basis

SCE currently has the capability of metering in 15-minute intervals the energy delivered to (or received from) its self generating customers. Currently, metered data is billed on a monthly basis and none of our tariffs require "real time" monitoring. It is conceivable, however, that some demand response benefit could result from the ability to monitor, in real time, which customers are not generating during peak periods. We have not attempted to estimate the value of this benefit or the cost to implement it. We have included some benefit that is expected to result from our ability to provide the customer with real time, interval consumption data as part of the demand response benefit (see benefit code CB-8 below).

m) (SB-13) Reduction in the Amount of Time to Implement New Rates or Load Management Programs

The SB-5 benefits addressed above recognize the ability to redefine TOU time periods, or seasons, without the need to physically reprogram meters in the field. The time required to make such a change with the majority of today's meters is actually prohibitive.

2. Customer Service Benefits (CB-1 through CB-13)

The July 21, 2004 Ruling identified 13 "additional" Customer Service Benefits. Our review of these potential areas of benefit resulted in anticipated savings from two of the 13. Total savings in Scenario 4 was $8.3 million. Of this total, $5.4 million is the result of improved billing accuracy due to the elimination of estimated bills, more timely billing, and the elimination of meter accessibility problems (CB-1), and the remaining $2.9 million is the

[62] This could add as much as $1.3 million per year to our cost of energy.

result of ancillary benefits derived from improved web site capabilities necessary to provide interval usage data to customers (CB-8).

This section will address our review and conclusions relating to each of the 13 potential Customer Service Benefits.

a) (CB-1) Improves Billing Accuracy – Provides Solution for Inaccessible / Difficult to Access Sites – Eliminates "Lock-Outs"

Inaccessible and/or locked meter sites are the primary reason for estimated and/or untimely bills. Automated retrieval of meter reads eliminates these meter access problems and reduces the need to estimate monthly meter reads. This, in turn, eliminates the need for many "pick-up" reads and billing inquiry investigations. We have estimated the savings related to this benefit to be approximately $5.4 million for all full deployment scenarios over the duration of the analysis period.

Additional related benefits in the Call Center have been identified under benefit code SB-4.

b) (CB-2) Early Detection of Meter Failures and Distribution Line Stresses Can reduce Outages and Improve Customer Service

The two-way radio communications capability of the AMI system would give us the ability to verify whether any particular meter is currently in or out-of-service. This would potentially eliminate the need for a field response to approximately 10 percent of our single-service no-lights calls. This is because approximately 10 percent of single-service no-lights calls have utility service and the interruption is attributable to electrical problems on the customer's side of the meter. We estimate this benefit would eliminate about 2,500 field calls (or roughly 2,500 Troubleman hours) per year, which equates to the full time equivalent of 1.5 Troublemen. To accomplish this savings would require installation of the Call Center systems interface and the necessary communications protocol to facilitate the real-time verification process. We have not attempted to estimate the cost of such a systems interface, but have assumed that the costs would likely offset most of the anticipated benefit. No savings have been included for this benefit code.

c) (CB-3) May Provide Additional Opportunity to Inspect Panel, Reattachment of Unsecured Meter Boxes, Identify Any Unsafe Conditions

We do not view AMI as an opportunity for additional meter panel inspections. To the contrary, we consider our meter reader to be our eyes and ears in the field, providing a monthly meter panel inspection and identifying any unsafe conditions, such as dogs, loose or constricted service panels, *etc*. AMI implementation would eliminate this monthly site inspection currently provided by meter readers. This is likely to lead to unforeseen cost increases, not cost savings. No savings have been included for this benefit code.

d) (CB-4) Improves Billing Accuracy – Reduced Estimated Reads / Estimated Billing – Reduced Exception Billing Processing

Any potential cost savings for this benefit code have been included in the estimate for benefit code CB-1 above.

e) (CB-5) Customer Energy Profiles for EE / DR Targeting (Marketing)

It seems reasonable to assume that individual customer load profile data would be useful in targeting likely candidates for various future energy efficiency and demand response programs. Until the data becomes available for review, it would be very difficult to determine to what extent such usage information would actually be useful, and what value it might have above and beyond the data available today. No attempt has been made to quantify this potential future benefit.

f) (CB-6) Customer Rate Choice / Customer Rate Options

As discussed previously under benefit codes SB-5 and SB-13, full scale implementation of AMI would increase our ability to add new customer rate options. The benefits derived from the ability to expand on new time-differentiated rates are included in the demand response (DR) benefits.

g) (CB-7) Customized Billing Date

Because we would no longer be locked in to fixed meter-reading cycles, it would be possible to offer AMI metered customers a choice of when, during the month they would prefer to be billed. This could conceivably provide some cash-flow and/or payment flexibility benefit to those customers. It is hard to see how this provides any direct benefit to SCE, however, beyond some level of improved customer satisfaction which is difficult to quantify. It is also likely that any cash flow advantage to large customers, taking advantage of timing their own cost cycle, could result in a cash-flow disadvantage to SCE. No value has been included for this benefit code.

AMI would also give SCE the ability to change billing dates to enable more efficient use of billing cycles and to improve cash flow from its summary billing accounts. This benefit is discussed in benefit code MB-5.

h) (CB-8) Energy Information to Customer Can Assist in Managing Loads

We expect a direct benefit of approximately $2.9 million as part of the demand response analysis resulting from usage data availability to customers through SCE's website. This benefit is largely offset by the added cost of expanding the web site capacity to accommodate this anticipated increase in activity. These offsetting website costs are included in cost code CU-9.

i) (CB-9) Enhanced Billing Options Could Be a Source of Revenue and Increased Customer Satisfaction.

The prospect of today's AMI technology opening-up an array of potentially new business ventures is highly speculative. To what extent SCE would be able to participate in these new, undefined business ventures is unclear at this point and no value has been included for this benefit code.

j) (CB-10) Load Survey – AMI Systems Allow Utilities to Perform Load Surveys Remotely and No Longer Require Recruitment and Site Visits

SCE's current load surveys utilize 15-minute interval data for the residential, GS-1 (small commercial below 20 kW), GS-2 (20 to 200 kW) and agricultural customer samples. Our AMI deployment assumptions stipulate that, 15-minute data would normally be retrieved only from customers with demands above 20 kW. With special programming, we believe we would be able to retrieve 15-minute data for a select group (a statistical sample) of residential and GS-1 accounts as well. This would eliminate the need for special metering at load survey sites. The cost of performing the load survey sample design and analysis would, however, still remain.

In Scenario 4, we have included all load survey metering costs in our avoided cost of new and replacement meters in benefit code MB-4.

k) (CB-11) On-line Bill Presentment With Hourly Data / More Timely and Accurate Information About Electricity / Information Access

See discussion under benefit code CB-8.

l) (CB-12) Value to Customers of More Timely And Accurate Bills

See discussion under benefit codes CB-1, CB-4 and CB-7.

3. Demand Response Benefits [DR-1 through DR-4]

The July 21, 2004 Ruling identified four potential Demand Response benefit categories to be evaluated in the business cases. Those categories are:

- DR-1: Procurement cost reduction;
- DR-2: System reliability benefits (capacity buffer);
- DR-3: Dynamic fuel switching/dynamic integration of conventional and distributed supplies; and
- DR-4: Avoided/deferred transmission and distribution (T&D) additions / upgrade costs.

For SCE, only DR-1 and DR-2 provide quantifiable benefits that should be included in the business case analyses. Our approach and assumptions for each Demand Response benefit category is described in the following sections.

a) DR-1: Procurement Cost Reduction

TDRs enabled by AMI that result in peak load and energy reductions would yield a reduction in the utility's procurement costs. Such costs that are truly avoided should be counted as benefits in the business case. Avoided costs can be estimated by a "proxy method" where a simple assumption is made that the procurement costs avoided are calculated assuming a single avoided resource cost for capacity and for energy, at all times, as an approximation of the actual costs avoided which in practice vary hour by hour and day by day.

The Commission directed parties to use a "proxy method" namely, \$85/kW-yr for capacity savings and \$70/MWh (\$63/MWh for peak energy plus \$7/MWh for congestion) for the energy savings provided by TDR load reductions. Off-peak energy was assigned a value of \$45/MWh. The values for peak energy are similar to the levelized capital cost of a combustion turbine (CT) operating at a gas price of close to \$6/MMBTU.

The avoided resource value of demand response from TDRs and different characteristics than a CT and their respective values, as resource are not equivalent. SCE used both the required avoided cost values provided in the July 21, 2004 Ruling and adjusted avoided resource values for the capacity component of avoided procurement costs as set forth in Appendix D.

Finally, we applied a distribution loss factor adjustment by increasing the capacity and energy benefits by 8.4 percent. This is a reasonable proxy for distribution losses at peak times (high temperatures) that would be incurred by generation supplies.[63]

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[63] This is for losses between the end use meter and the generator. Average annual distribution loss factors in the 5 percent range.

b) DR-2: System Reliability Benefits (Capacity Buffer)

We agree that for load reductions from "reliable" load response to TDRs, reserve requirements are avoided. We apply a system reliability benefit of 15 percent reserves to the counted load response. We calculate a value for this benefit at the avoided capacity cost defined by the July 21, 2004 Ruling ($85/kW-year) and by what we believe to be our actual avoided marginal reserve cost of $80/kW-year.

c) DR-3: Dynamic Fuel Switching/Dynamic Integration of Conventional and Distributed Supplies

TDRs enabled by AMI do not provide reliable and rapid response that would enable or improve the dispatch of resources on our system above and beyond the current methods and system capabilities. For example, we have system monitoring and metering at a substation level. It unclear how increased granularity from interval metering at the end use will provide us additional information to facilitate fuel switching or the integration of distributed generation. For purposes of this analysis, the avoided cost savings attributable to AMI for dynamic integration benefits are included in the capacity payment since this payment reflects the cost of a combustion turbine that provides full dispatch capability. Including a separate adder would amount to double counting the savings attributable to dynamic integration benefits.

AMI metering at the residential level is not likely to be aggregated or evaluated in a way timely for fuel switching. AMI does not provide measurable benefits since the amount of energy saved by the AMI program is minimal. Significant fuel diversity savings are caused by programs that save a significant amount of energy thereby affecting the fuel mix required to produce energy.

Moreover, it is unknown how such information, assuming more geographic granularity is better, would translate to quantifiable benefits. Of course, if there were potential benefits to consider, the costs associated with the required systems and applications would also need to be included. Accordingly, without better information concerning this category at this point, we have omitted any potential benefit from fuel switching.

d) DR-4: Avoided/Deferred Transmission and Distribution (T&D) Additions/Upgrade Costs

For a number of reasons, we do not believe that TDRs enabled by AMI provide transmission and distribution upgrade deferral benefits. We first describe below transmission upgrade issues and then explain distribution upgrade issues.

Transmission network upgrades or expansions are required to avoid congestion. However, congestion on specific transmission lines can be caused by generator or system outages and more typically occurs during shoulder months rather than at peak times, when most supply-side resources are available. In fact, reductions in load in certain locations on the network could cause congestion in other areas. Secondly, TDRs are subject to change. If a transmission upgrade was deferred due to expected demand reduction from a TDR and the rate is modified or discontinued, as in the case of Puget Sound Energy explained earlier, system reliability could be immediately threatened. Ultimately, there is a possibility that significant and durable demand response could result in deferring transmission upgrades. However, we believe that counting such benefits in a business case when Commission and legislative intervention in rates has been demonstrated in the past, such as in the case of AB1-X, is not appropriate.

With respect to distribution additions/upgrades, we believe that it is not appropriate to count distribution upgrade deferrals as benefits due to uncertainty concerning rates. In addition, TDRs, especially if CPP programs were implemented widely, could actually cause more simultaneous loading on the distribution network when the rate changes from peak to off peak. For example, assume a residential distribution circuit sized to handle 20 MW of otherwise diversified residential customer load. By signaling a CPP event, customers are encouraged to not use energy during a set peak period. When the CPP event ends and those customers who responded to the program begin to use energy again, there is a risk that the increased coincidence associated with this load will create a higher than otherwise peak load on that distribution circuit. At the end of the CPP event, air conditioners are working hard to bring the temperature down to the desired comfort level at off-CPP peak prices. If there were a high number of customers on a CPP rate during a hot peak summer day the coincident peak loading of the simultaneous turn on of air conditioner compressors is called a "rebound effect."

The phenomenon of distribution system loading can be understood by examining the actual load profile of SPP participants on a CPP day where a higher peak than would otherwise occur was observed in the evening hours.

4. Management and Other Benefits (MB-1 through MB-10)

Only two of the ten potential "Management and Other" benefit codes identified in the July 21, 2004 Ruling were actually used in SCE's analysis. The following sections describe our review of each of the potential Management and Other benefit codes.

a) (MB-1) Reduced Equipment And Equipment Maintenance Costs (Software Maintenance And System Support, Handheld Reading Devices, Uniforms, *etc.*)

In Scenario 4, we expect to reduce costs by approximately $2.9 million over the duration of the analysis period by decommissioning 80 percent of our hand-held meter reading devices. Typically these electronic devices would be replaced every five years. This is a cost that would no longer be incurred under full AMI deployment.

b) (MB-2) Reduced Miscellaneous Support Expenses (Including Office Equipment and Supplies)

These savings have been included in the SB-1 benefit.

c) (MB-3) Reduced Battery Replacement / Calendar Resets / Meter Programming

Because SCE has already begun to use interval metering for its TOU and interval data needs, no incremental savings would accrue as a result of replacing existing metering with AMI meters. See related discussion under benefit code SB-5.

d) (MB-4) Reduced Meter Inventories / Inventory Management Expenses due to Expanded Uniformity

Electronic meters have a broader range of functionality than do their electromagnetic predecessors. This enables us to carry fewer meter types in inventory than was formerly the case. This benefit is already being utilized, given that SCE has already started replacing all large customer meters and all time-of-use meters with RTEM or interval meters. This benefit is offset in large part by the higher failure rate of electronic meters compounded by their inherently shorter useful life, both of which result in higher inventory turn-over. The AMI system will introduce higher volumes of inventories for communications equipment, and replacement parts than existed previously. For these reasons, we have not included any benefit value for reduced meter inventories.

This benefit code contains our avoided cost of purchasing approximately 72,000 conventional new and replacement meters each year for the full duration of the analysis period. As discussed in the Business As Usual case (Appendix G) the material cost of 72,000 new and replacement non-AMI meters each year is significantly different than the replacement cost of these same 72,000 meters each year using AMI meters. For this reason, the total cost of all new and replacement AMI meters has been included in all AMI scenarios in cost code MS-3. The avoided cost of not purchasing conventional meters for customer growth and routine replacements is included in this benefit code. For Scenario 4, this avoided cost is $118.2 million over the duration of the analysis period.

e) (MB-5) Summary Billing Cash Flow Benefits (Existing Customers)

SCE currently has approximately 418,000 individual service accounts being billed monthly on approximately 118,000 summary billing accounts (approximately 3.5 accounts per summary bill on average). Because the individual accounts are currently being read throughout the month, billing for the earlier read accounts is necessarily delayed until the last account is read, in order to bill all service accounts on the summary bill at the same time. This results in significant cash lag for these accounts. Theoretically, full deployment of AMI would allow us to synchronize the read dates for all service accounts on summary bills, virtually eliminating the current cash lag. The recent deployment of RTEM metering already provides the means to achieve a large part of this potential savings, since most of the cash lag is attributed to large customers over 200 kW. Full AMI deployment could result in further savings, as most of our summary billed service accounts' meters become automated.

f) (MB-6) Possible Reduction In "Idle Usage," Meter Watt Losses – at the Very Least, Quicker Resolution of Idle Usage Episodes.

AMI meters have the ability to meter smaller loads (below 25 watts) than do existing electromagnetic meters. Most electromagnetic meter discs sit "idle" when less than 20 to 25 watts are being consumed. Our review of our existing residential load survey data shows that some minimum load between 0 and 25 watts exists approximately 3.5 percent of the time (*i.e.*, approximately one hour per day, on average). Though significant time-wise, the actual energy consumed during this un-metered hour is less than 0.004 percent of total metered kWh on average. For an average residential customer, this would equal approximately 25 watt-hours per month. On an annual basis, we estimate that under full deployment, all AMI meters would meter a total of approximately 1.4 million kWh per year (approximately $60,000 in energy costs) more than their electromagnetic predecessors. More accurate measurement of this energy would not result in any cost savings, but merely in a reallocation of these costs to those customers responsible for this currently un-metered load.

Because the value of this unmetered load is so small, we have not included any savings attributable to this benefit in the full or partial deployment scenarios.

The "watts lost" rating of an electronic meter is typically greater than that of the single phase electro-mechanical meter it would be replacing. We estimate the average AMI meter would be rated at approximately one watt higher than their electro-mechanical counterparts. Taken on its own, this technical characteristic of electronic meters would add 4 megawatts of load 24 hours a day, 365 days per year. This would add over 35 million kWh per year in energy consumption.

An "idle usage episode" occurs when a routine meter reading results in some consumption being recorded for an account that is supposed to be turned-off (or "idle"). This situation occurs when a customer moves into a home or business and fails to notify SCE that they have turned the service on and have begun to use electricity. Typically, it can take 30 to 60 days to detect and investigate this occurrence and finally issue a bill to resolve the problem. Theoretically, with AMI metering, we expect such idle meter episodes can be detected 15 days sooner on average, resulting in a higher probability of obtaining compensation for the unauthorized use, and a reduction in revenue lag. In reality, most idle usage episodes resolve themselves within a matter of days of their occurrence and, as a practical matter, because of the service disconnect costs, exception bill processing, and other related costs of idle usage resolution, we do not attempt to notify the customer of a pending disconnect until a threshold of 400 aggregated kWh is exceeded. Identifying idle usage episodes in a more timely manner with AMI meters does little to remove these more practical processing cost considerations and any actual savings would be insignificant.

g) <u>(MB-7) Possible New Revenue Source / New Business Ventures / New Products and Services / Web Based Interval and Power-Quality Data</u>

See discussion under benefit code CB-9 above.

h) (MB-8) May Facilitate Ability To Obtain GPS Reads During Meter Deployment – Improving Franchise and Utility Tax Processes

GPS reads will be recorded for all meter locations during the installation phase of AMI deployment. This will be done in order to be able to mark the actual location of the meter site, since it may be several years before we will ever have to revisit the meter. The GPS read will reduce the odds of physically "losing" the meter as customers add walls and fences, making it difficult to keep track of the meter and its access route. It is conceivable that these GPS reads can be incorporated into the Franchise Payment and Utility User Tax processes, in order to assure more accurate processing of these fees. Because there would be offsetting costs to develop the systems interface to facilitate the use of GPS readings, a much more intense review of costs and benefits would have to be undertaken to determine the economic feasibility of this potential benefit.

i) (MB-9) Tariff Planning – More Flexibility of Rate Contacts And Options Within Standard Customer Rate Classes / Dynamic Tariffs

See discussion under benefit codes SB-5, SB-13, and CB-6.

j) (MB-10) Potential for Tax Savings from Federal Investment Tax Credits

We are not aware of any Federal Investment Tax Credits that would apply to AMI deployment under current law, and no such benefit has been included in the full or partial deployment scenarios.

All benefit codes identified in the July 21, 2004 Ruling, are discussed in the following sections, whether included in the final business case analysis or not.

E. Summary of Potential Benefits Partial AMI Deployment

All benefit codes identified in the July 21, 2004 Ruling are discussed in the following sections, whether in the analysis or not.

1. System Operations Benefits (SB-1 through SB-13)

Appendix A of the July 21, 2004 Ruling identified 13 potential system operations benefits that may result from deployment of AMI. In our initial review of these potential benefits, we have been able to quantify savings coming from three of the 13 benefit codes for a total of $29.3 million for all partial deployment scenarios. We expect some net benefit from two other benefit codes, which we are not able to quantify at this time. The remaining seven potential areas of benefit identified in the July 21, 2004 Ruling are either already being experienced by SCE, have associated costs that more than offset the anticipated savings, or otherwise do not apply.[64] The following sections address all 13 of the potential system operations benefits as described in the July 21, 2004 Ruling.

a) (SB-1) Reduction in Meter Readers, Management, and Administrative Support (And Associated Costs)

This is the single largest area of benefits expected to accrue from partial implementation of AMI. We expect 32 meter reading positions will be eliminated, resulting in total cost savings of approximately $26.3 million over the analysis period. We expect AMI will give us the ability to remotely read approximately 70 percent of all meters in Zone 4 (70 percent of 442,000 = 309,000). The remaining 133,000 meters that cannot be read through the AMI system will continue to be read manually on a monthly basis by approximately 40 Meter Readers.[65] We do not expect to eliminate any of the existing Meter Reader Supervisor positions under the partial deployment scenarios since each of the three major districts involved have only one supervisor who oversees both Field Services and Meter Reading field activities. Additional savings will result from the decommissioning of 30 hand-held meter reading devices. This savings is reflected in benefit code MB-1.

[64] Several cost codes were found to be duplicative of one another. Where this occurs, we point out the duplicate cost code to avoid double counting.

[65] The remaining 30 percent of the meters with which we are unable to communicate are scattered throughout the Zone 4 area and are generally not adjacent to one another, thus making routine meter reading less efficient than it is today.

b) SB-2 Field Service Savings (Turn-Ons / Turn Offs) And Lower Need For Pickup Reads

SCE currently completes nearly half of its "turn-off" and "turn-on" meter orders without having to actually turn the meter on or off. This situation occurs when a "turn-on" order can be matched to a "turn-off" order for the same location, on or about the same day. Such orders can be completed merely by taking a meter read, which currently requires a visit to the site at an average cost of approximately $15 per order. Virtually all of these special meter reads for matched on/off meter orders could be eliminated and replaced with the daily AMI meter read. Under partial AMI deployment, this benefit would result in the reduction of five FTEs and approximately $2.8 million in total costs over the duration of the analysis period.

c) (SB-3) Reduction in Energy Theft – May Provide Ability to Identify Active Accounts for Metered Accounts Not Being Billed, Broken Meters, Wrong Multipliers

In reviewing this "potential benefit," we were unable to identify any incremental savings that may accrue due to the deployment of AMI. All three of these situations can be identified as readily (if not more readily) by a Meter Reader making an actual observation of the meter installation on a monthly basis. The Meter Reader is our primary means of identifying potential meter tampering and energy theft, especially in those instances where the meter is bypassed or "jumpered" and the integrity of the meter itself is not affected. Although we expect to uncover a number of energy theft situations during the installation phase of AMI that may have otherwise gone undetected, the additional investigators required to resolve these new cases will remain in place after the installation phase in order to complete investigations and make optimum use of information derived from the AMI system to track, monitor and perform ongoing investigations.

Energy consumption on accounts not being billed may be identified more quickly under Scenarios 4 and 17, given that daily reads will be available. This benefit is relatively small and is addressed under "Idle Usage Episodes" in benefit code MB-5 below.

We believe both energy theft and broken meters would be harder–not easier–to identify through AMI, given that physical tampering is not readily apparent through automated meter readings and a zero read does not necessarily indicate a broken meter. Many broken meters continue to register consumption, though it may not be correct. Rather than identifying any SB-6 benefits, we have actually identified several potential risks related to these collective issues using today's AMI technology.

d) (SB-4) Phone Center Reduced FTEs in the Long-Term Due to Anticipated Lower Customer Call Volume (Estimated / Disputed Bills)

Billing inquiries today are received for several reasons, only one of which is an inaccurate meter read. Based on a study using 2003 data, 22,791 inquiries to the Call Center were a result of meter reading errors. We used this number as a percentage of all calls to determine the percent of calls in subsequent years that would be projected as meter read error calls. For purposes of this analysis, we assume that 100 percent of these calls currently coming from Zone 4 will be avoided with the partial (Zone 4) deployment of AMI.

Table H-2 shows the number of avoided calls that may result from the elimination of meter reading errors in Zone 4. Using 3,376 as the average number of Billing Inquiry calls answered per FTE in the Billing Inquiry specialty support group during 2003, under partial deployment we estimate a reduction of 0.6 FTEs for a total benefit of $0.4 million through 2021.

Table H-2 Reduced Phone Calls						
Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Partial Deployment	0	2,216	2,216	2,216	2,216	2,216

e) (SB-5) Possible Productivity Enhancement / Rate Changes Simplified / Possible Reprogram Rather Than Meter Change

Some currently-installed TOU meters would require re-programming in the field if the Commission ordered a change in the definition of time-of-use on and off-peak time periods, seasonal definitions, holidays, *etc*. This programming limitation does not exist with AMI meters because they record 15-minute and hourly consumption data.

This is a benefit that SCE will already obtain because we are systematically changing our existing TOU meters to electronic interval data recorders. This effort is expected to be completed by the end of 2005.[66] The value of having the ability to more readily apply time differentiated rates to a vast majority of our customers through AMI deployment is included in the demand response (DR) benefit codes to be described later.

f) (SB-6) Outage Management Benefits

This potential benefit of today's AMI technology has been addressed in the Business As Usual case in Appendix G as follows: "Because we already have adequately functioning OMS, TLM, and SCADA systems, we already obtain associated benefits in our T&D activities. As such, the potential added value related to outage management, transformer loading, and other T&D benefits that otherwise might accompany AMI for some utilities is virtually nonexistent for SCE. We have not included any incremental costs or benefits of AMI relative to these systems in our partial deployment scenarios."[67]

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66 SCE's Meter Infrastructure Replacement program is described in SCE's 2006 GRC Application in SCE4 Vol. 2, Chapter V.

67 *See* Appendix G.

We have identified some savings attributable to the ability to confirm individual service outages when "no-lights" trouble calls are received at the Call Center. This has been quantified and discussed under benefit code CB-2.

g) (SB-7) Better Meter Functionality / Equipment Modernization

The broader range of functionality of new electronic meters, such as those that would be used for AMI, provides advantages over their electro-mechanical predecessors. The most apparent advantage is the universal "one-size-fits-all" capabilities of the modern meter. Although there are still a number of variations in "meter forms," (the configuration of the meter stabs connecting it to the panel socket) and instrument transformers are still the norm for large accounts, the number of variations is not nearly as broad as it once was. The result is a potential for reduced meter inventories (see benefit code MB-4) and the ability to carry replacements for most meters in field vehicles. Because we are already using RTEM or interval metering for our larger C&I accounts, we are already taking full advantage of this functionality benefit through normal business operations and as captured in the "Business As Usual" case. This more universal metering functionality is less evident among smaller C&I and residential accounts and is recognized as a qualitative benefit arising from any future AMI deployment.

The incorporation of two-way communications provides the potential for meter diagnostics and voltage verification that do not exist today. AMI meters would also provide the potential means to alert the customers of system peaks and could automatically trigger some form of direct load control. They could also provide a means to allow the customer to access their own metered data for use in reducing consumption during peak periods. These are all recognized as qualitative benefits. However, each of these optional functions carries offsetting costs that are not readily quantifiable at this time. Since incremental costs are not available, we are not able to determine the economics of including any or all of these functional options in this analysis.

h) <u>(SB-8) Remote Service Connect / Disconnect</u>

We respond to over 1 million turn-on/turn-off service requests annually, and we disconnect and reconnect nearly 1 million additional meters for credit related, non-payment issues. Nearly one-half of the on/off service requests and all of the credit disconnects require the physical disconnection of service at the customer's meter. AMI meters could be equipped with a remote disconnect switch contained within the meter, which could provide the ability to "remotely" turn electric service on or off.

However, this is a costly option to be added to an AMI meter. A typical 200 amp disconnect switch (not including additional hardware/software necessary to activate) would cost approximately $150 to $200 per meter. By comparison, we currently incur a cost of approximately $17 to respond to a next day on/off service order and approximately $24 for same-day service. Thus, the installation of a remote disconnect switch would only make sense where there is frequent customer turn-over (*i.e.*, student housing, apartment complexes, *etc.*) and/or where credit collection problems exist. Even with turn-over rates of two or three per year at any specific location, the cost effectiveness of this option today is marginal at best. Therefore, we have not included the remote service connect / disconnect functionality in our technology selection, nor have we included any related benefit in the partial deployment scenarios.

i) <u>(SB-9) Meter Accuracy-Improved and More Timely Load Information Could Increase Forecasting Accuracy and Reduce Resource Acquisition Costs and Reduce Customer Complaints About Faulty Meter Reads</u>

A new solid state meter is slightly more accurate over the full range of its rated load capability than its electro-mechanical predecessor. A cost savings has been estimated for reduced call volume relating to billing inquiries as described in SB-4 above. On the other hand, the potential for increased initial failure rates for current AMI technology (as was the case with RTEM meters) has been identified as a potential risk and results in significant cost increases in the Billing Organization due to increased meter order and exception processing (see cost codes CU-1, CU-4, and I-11).

Because customer load information would be available in a more timely manner (*i.e.,* hourly, daily, weekly, *etc.*), full AMI deployment will provide some benefit to SCE with regard to forecasting accuracy and in reducing resource acquisition costs. These costs savings have been identified in the demand response analysis.[68] No similar benefit has been included for partial AMI deployment.

Benefits derived from improved "billing accuracy" are discussed below under benefit code CB-1.

j) (SB-10) System Planning Design Efficiency – Savings from More Accurate Information on Status of Transformers And Distribution Lines Etc.

In theory, AMI would give us the opportunity to aggregate coincident customer loads within any specific area in order to determine the demand on a distribution circuit or an individual distribution transformer. In reality, however, distribution circuit loads are dynamic and cannot be assumed to be confined to any geographic area over any extended period of time. This is because sections of load are constantly being switched from one circuit to another (and from one transformer to another) during circuit interruptions, for routine maintenance, and for load balancing purposes. We estimate that we are currently able to match only 80 to 85 percent of our customers with their serving transformer at any given time. SCE already has a Transformer Load Management program in place that already provides this information for distribution planning purposes (see benefit code SB-6). As such, we do not expect deployment of today's AMI technology to create any incremental benefits in this area.

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[68] *See* Appendix C.

k) (SB-11) Reduction in Unaccounted for Energy (UFE)

As described above, AMI could theoretically give us the opportunity to aggregate customer loads within any specific geographic area in order to determine the demand on any particular distribution circuit. Even if this were technically feasible, it is not clear how this aggregated load information will assist in identifying the source of UFE.

We currently have the ability to analytically model system losses using customer load profile data compared to total system generation, and have concluded that the amount of UFE is not significant enough to warrant any further investigation of the sort suggested as a potential benefit under AMI deployment.

The "watts lost" rating of an electronic meter is typically greater than that of the single phase electro-mechanical meter it would be replacing. We estimate the average AMI meter would be rated at approximately one watt higher than their single phase electro-mechanical counterparts.

l) (SB-12) Ability to Monitor Customer Self-Generation Into System on a Real Time Basis

SCE currently has the capability of metering in 15-minute intervals the energy delivered to (or received from) its self generating customers. Currently, metered data is billed on a monthly basis and none of our tariffs require "real time" monitoring. It is conceivable, however, that some demand response benefit could result from the ability to monitor, in real time, which customers are not generating during peak periods. We have not attempted to estimate the value of this benefit or the cost to implement it. We have included some benefit that is expected to result from our ability to provide the customer with real time, interval consumption data under the demand response scenarios (see benefit code CB-8 below).

m) (SB-13) Reduction in the Amount of Time to Implement New Rates or Load Management Programs

The SB-5 benefits addressed above recognize the ability to redefine TOU time periods, or seasons, without the need to physically reprogram meters in the field. The time required to make such a change with the majority of today's meters is actually prohibitive. However, for the vast majority of customers on TOU rates, there has not been a compelling reason to redefine time periods or seasons in recent years. As part of the demand response analysis, the ability to implement new rates in a timely manner, especially rates with narrower on-peak periods (or variable peak periods), would be a significant qualitative benefit and would eliminate a major obstacle to periodically re-defining TOU periods when warranted.

Under Scenario 17, we see no incremental savings attributable to this potential benefit over our "Business As Usual" base case. This is because we are already replacing our existing pre-programmed TOU meters with interval meters, and thus we will already derive this benefit. With regard to the demand response scenarios, as was the case with benefit code CB-5, the benefits to be derived from optimizing customer participation on various new rate options is included in the demand response (DR) benefits.

2. Customer Service Benefits (CB-1 through CB-13)

The July 21, 2004 Ruling identified 13 "additional" customer service benefits. Our review of these potential areas of benefit under partial AMI deployment resulted in anticipated savings from three of the thirteen, for a total savings of approximately $4.0 million in the demand response benefit. Of this total, $1.1 million is the result of improved billing accuracy due to the elimination of estimated bills, more timely billing, and the elimination of meter accessibility problems (CB-1), the remaining $2.9 million is the result of ancillary benefits derived from improved website capabilities necessary to provide interval usage data to customers (CB-8). This section will address our review and conclusions relating to each of the 13 potential Customer Service Benefits under partial AMI deployment.

a) (CB-1) Improves Billing Accuracy – Provides Solution for Inaccessible / Difficult to Access Sites – Eliminates "Lock-Outs"

Inaccessible and/or locked meter sites are the primary reason for estimated and or un-timely bills. Automated retrieval of meter reads eliminates these meter access problems and reduces the need to estimate monthly meter reads. This, in turn, eliminates the need for many "pick-up" reads and billing inquiry investigations. We have estimated the savings related to this benefit to be approximately $1.1 million for Scenario 17 over the duration of the analysis period.

Additional related benefits in the Call Center have been identified under benefit code SB-4.

b) (CB-2) Early Detection of Meter Failures and Distribution Line Stresses Can reduce Outages and Improve Customer Service

The two-way radio communications capability of the AMI system would give us the ability to verify whether any particular meter is currently in or out-of-service. This would potentially eliminate the need for a field response to approximately 10 percent of our single-service no-lights calls. This is because approximately 10 percent of single-service no-lights calls have utility service and the interruption is attributable to electrical problems on the customer's side of the meter. We estimate this benefit would eliminate about 2,500 field calls (or roughly 2,500 Troubleman hours) per year, which equates to the full time equivalent of 1.5 Troublemen. To accomplish this savings would require installation of the Call Center systems interface and the necessary communications protocol to facilitate the real-time verification process. We have not attempted to estimate the cost of such a systems interface, but have assumed that the costs would likely offset most of the anticipated benefit. No savings have been included for this benefit code.

c) (CB-3) May Provide Additional Opportunity to Inspect Panel, Reattachment of Unsecured Meter Boxes, Identify Any Unsafe Conditions

We do not view AMI as an opportunity for additional meter panel inspections. To the contrary, we consider our meter reader to be our eyes and ears in the field, providing a monthly meter panel inspection and identifying any unsafe conditions, such as dogs, loose or constricted service panels, *etc*. AMI implementation would eliminate this monthly site inspection currently provided by meter readers. This is likely to lead to unforeseen cost increases, not cost savings. No savings have been included for this benefit code.

d) (CB-4) Improves Billing Accuracy – Reduced Estimated Reads / Estimated Billing – Reduced Exception Billing Processing.

Any potential cost savings for this benefit code have been included in the estimate for benefit code CB-1 above.

e) (CB-5) Customer Energy Profiles for EE / DR Targeting (Marketing)

It seems reasonable to assume that individual customer load profile data would be useful in targeting likely candidates for various future energy efficiency and demand response programs. Until the data becomes available for review, it would be very difficult to determine to what extent such usage information would actually be useful, and what value it might have above and beyond the data available today. No attempt has been made to quantify this potential benefit.

f) (CB-6) Customer Rate Choice/Customer Rate Options

As discussed previously under benefit codes SB-5 and SB-13, implementation of AMI would increase our ability to add new customer rate options. The benefits derived from the ability to expand on new time-differentiated rates are included in the demand response (DR) benefits.

g) (CB-7) Customized Billing Date

Because we would no longer be locked in to fixed meter reading cycles, it would be possible to offer AMI metered customers a choice of when, during the month they would prefer to be billed. This could conceivably provide some cash-flow and/or payment flexibility benefit to those customers. It is hard to see how this provides any direct benefit to SCE, however, beyond some level of improved customer satisfaction which is difficult to quantify. It is also likely that any cash flow advantage to large customers, taking advantage of timing their own cost cycle, could result in a cash-flow disadvantage to SCE. No value has been included for this benefit code.

AMI would also give us the ability to change billing dates to enable more efficient use of billing cycles and to improve cash flow from its summary billing accounts. This benefit is discussed in benefit code MB-5.

h) (CB-8) Energy Information to Customer Can Assist in Managing Loads

We expect a direct benefit of approximately $2.9 million as part of the demand response benefits resulting from usage data availability to customers through SCE's website. This benefit is largely offset by the added cost of expanding the web site capacity to accommodate this anticipated increase in activity. These offsetting website costs are included in cost code CU-9.

i) (CB-9) Enhanced Billing Options Could Be a Source of Revenue and Increased Customer Satisfaction.

The prospect of AMI opening-up an array of potentially new business ventures is highly speculative. To what extent we are able to participate in these new undefined business ventures is unclear at this point and no value has been included for this benefit code.

j) (CB-10) Load Survey – AMI Systems Allow Utilities to Perform Load Surveys Remotely and No Longer Require Recruitment and Site Visits

Partial deployment of AMI would not provide the appropriate statistical representation of the total SCE system that is required for load survey purposes. The full deployment case addresses savings for this benefit code.[69]

k) (CB-11) On-line Bill Presentment With Hourly Data/More Timely and Accurate Information About Electricity/Information Access

See discussion under benefit code CB-8.

l) (CB-12) Value to Customers of More Timely & Accurate Bills

See discussion under benefit codes CB-1, CB-4 and CB-7.

3. Demand Response Benefits

The July 21, 2004 Ruling identified four potential Demand Response benefit categories to be evaluated in the business cases. Those categories are:

a) DR-1: Procurement cost reduction;

b) DR-2: System reliability benefits (capacity buffer);

c) DR-3: Dynamic fuel switching / dynamic integration of conventional and distributed supplies; and

d) DR-4: Avoided/deferred transmission and distribution (T&D) additions / upgrade costs.

For SCE, only DR-1 and DR-2 provide quantifiable benefits that should be included in the business case analyses.

4. Management and Other Benefits

Only two of the 10 potential "Management and Other" benefit codes identified in the July 21, 2004 Ruling were actually used in SCE's analysis. The following sections describe our review of each of the potential Management and Other benefit codes.

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[69] *See* Volume III, Section IV.

a) (MB-1) Reduced Equipment and Equipment Maintenance Costs (Software Maintenance And System Support, Handheld Reading Devices, Uniforms, *etc.*)

For Scenario 17, 30 hand-held meter reading devices would be decommissioned for a total savings of $785,000. Typically these electronic devices would be replaced every five years. This is a cost that would no longer be incurred under partial AMI deployment.

b) (MB-2) Reduced Miscellaneous Support Expenses (Including Office Equipment And Supplies)

These savings have been included in the SB-1 benefit.

c) (MB-3) Reduced Battery Replacement/Calendar Resets / Meter Programming

Because SCE has already begun to use interval metering for its TOU and interval data needs, no incremental savings would accrue as a result of replacing existing metering with AMI meters. See related discussion under benefit code SB-5.

d) (MB-4) Reduced Meter Inventories / Inventory Management Expenses due to Expanded Uniformity

Electronic meters have a broader range of functionality than do their electromagnetic predecessors. This enables us to carry fewer meter types in inventory than was formerly the case. This benefit is already being utilized, given that SCE has already started replacing all large customer meters and all time-of-use meters with RTEM or interval meters. This benefit is offset in large part by the higher failure rate of electronic meters compounded by their inherently shorter useful life, both of which result in higher inventory turn-over. The AMI system will introduce higher volumes of inventories for communications equipment, and replacement parts than existed previously. For these reasons, we have not included any benefit value for reduced meter inventories.

This benefit code contains our avoided cost of purchasing approximately 6,300 conventional new and replacement meters each year for the full duration of the analysis period. As discussed in the Business As Usual case (Appendix G) the material cost of 6,300 new and replacement non-AMI meters each year is significantly different than the replacement cost of these same 6,300 meters each year using AMI meters. For this reason, the total cost of all new and replacement AMI meters has been included in the full and partial AMI deployment scenarios in cost code MS-3. The avoided cost of not purchasing conventional meters for customer growth and routine replacements is included as a savings in this benefit code. For Scenario 17, this avoided cost is $10.5 million over the duration of the analysis period.

e) <u>(MB-5) Summary Billing Cash Flow Benefits (Existing Customers)</u>

SCE currently has approximately 418,000 individual service accounts being billed monthly on approximately 118,000 summary billing accounts (approximately 3.5 accounts per summary bill on average). Because the individual accounts are currently being read throughout the month, billing for the earlier read accounts is necessarily delayed until the last account is read, in order to bill all service accounts on the summary bill at the same time. This results in significant cash lag for these accounts. Full deployment of AMI would allow us to synchronize the read dates for all service accounts on summary bills, virtually eliminating the current revenue lag. However, under Scenario 17, we do not expect to gain any improvement in cash flow since we expect not enough individual service accounts could be synchronized to justify the necessary program and systems expenses to accomplish the needed changes.

f) <u>(MB-6) Possible Reduction In "Idle Usage", Meter Watt Losses – at the Very Least, Quicker Resolution of Idle Usage Episodes.</u>

AMI meters have the ability to meter smaller loads (below 25 watts) than do existing electromagnetic meters. Most electromagnetic meter discs sit "idle" when less than 20 to 25 watts are being consumed. Our review of our existing residential load survey data shows that some minimum load between 0 and 25 watts exists approximately 3.5 percent of the time (*i.e.*, approximately one hour per day on average). Though significant time-wise, the actual energy consumed during this un-metered hour is less than 0.004 percent of total metered kWh on average. For an average residential customer, this would equal approximately 25 Watt-hours per month. On an annual basis, we estimate that under partial deployment, AMI meters would meter a total of approximately 140,000 kWh per year (approximately $6,000 in energy costs) more than their electromagnetic predecessors. More accurate measurement of this energy would not result in any cost savings, but merely in a reallocation of these costs to those customers responsible for this currently un-metered load. Because the value of this unmetered load is so small, we have not included any savings attributable to this benefit in the full or partial deployment scenarios.

The "watts lost" rating of an electronic meter is typically greater than that of the single phase electro-mechanical meter it would be replacing. We estimate the average AMI meter would be rated at approximately one watt higher than their single phase electro-mechanical counterparts. Taken on its own, this technical characteristic of electronic meters would add four megawatts of load 24 hours a day, 365 days per year. This would add over three million kWh per year in energy consumption for the Scenario 17.

An "idle usage episode" occurs when a routine meter reading results in some consumption being recorded for an account that is supposed to be turned-off (or "idle"). This situation occurs when a customer moves into a home or business and fails to notify SCE that they have turned the service on and have begun to use electricity. Typically, it can take 30 to 60 days to detect and investigate this occurrence and finally issue a bill to resolve the problem. Theoretically, with AMI metering, we expect such idle meter episodes can be detected fifteen days sooner on average, potentially resulting in a higher probability of obtaining compensation for the unauthorized use, and a reduction in revenue lag. In reality, most idle usage episodes resolve themselves within a matter of days of their occurrence and, as a practical matter, because of the service disconnect costs, exception bill processing, and other related costs of idle usage resolution, we do not attempt to notify the customer of a pending disconnect until a threshold of 400 aggregated kWh is exceeded. The ability to identify idle usage episodes in a more timely manner with AMI meters will do little to remove these more practical processing cost considerations and any savings would be insignificant.

g) (MB-7) Possible New Revenue Source/New Business Ventures/New Products and Services/Web-Based Interval and Power-Quality Data

See discussion under benefit code CB-9 above.

h) (MB-8) May Facilitate Ability To Obtain GPS Reads During Meter Deployment – Improving Franchise and Utility Tax Processes

GPS reads will be recorded for all meter locations during the installation phase of AMI deployment. This will be done in order to be able to mark the actual location of the meter site, since it may be several years before we will ever have to revisit the meter. The GPS read will reduce the odds of physically "losing" the meter as customers add walls and fences, making it difficult to keep track of the meter and its access route. It is conceivable that these GPS reads can be incorporated into the Franchise Payment and Utility User Tax processes, in order to assure more accurate processing of these fees. Because there would be offsetting costs to develop the systems interface to facilitate the use of GPS readings, a much more intense review of costs and benefits would have to be undertaken to determine the economic feasibility of this potential benefit.

i) (MB-9) Tariff Planning – More Flexibility of Rate Contacts & Options Within Standard Customer Rate Classes / Dynamic Tariffs

See discussion under benefit codes SB-5, SB-13 and CB-6.

j) (MB-10) Potential for Tax Savings from Federal Investment Tax Credits

We are not aware of any Federal Investment Tax Credits that would apply to AMI deployment under current law, and no such benefit has been included in the full or partial deployment scenarios.

Appendix I

Estimating Large Customer Demand Reductions from Two-Part RTP

APPENDIX I

ESTIMATING LARGE CUSTOMER DEMAND REDUCTIONS FROM TWO-PART RTP

The July 21, 2004 Ruling required the analysis of large commercial and industrial customers (>200 kW) placed on a default basis to a two-part real time tariff, as part of certain AMI scenarios. This requirement could be interpreted to apply to Scenario 4. However, we believe that the consideration of the impact of a rate change on large customers is of interest but not as an AMI business case. This is because the investment in advanced metering for this customer class is already sunk. Since the July 21, 2004 Ruling, the Commission required utilities to make proposals to move the large customer class from TOU to CPP rates on a default basis. Should the Commission order CPP rates be implemented to this class on a default basis, the analysis of moving customers to RTP is significantly altered.

In compliance with the July 21, 2004 Ruling, our October 2004 and January 2005 preliminary business case analyses contained our analysis on two variations of implementing RTP and was submitted as Scenarios 12 and 13. In Scenario 12, we assumed that all large customers with RTEM meters are placed on a RTP rate on a mandatory basis. For Scenario 13, we assumed that our current Schedule I-6 interruptible program is maintained and all other large customers are placed on a RTP rate. Thus, Scenario 12 is a study of large customers on an RTP rate and Scenario 13 evaluates the mandatory implementation of RTP plus reliability provided by Schedule I-6.

This appendix describes the operational costs and benefits of these scenarios and provides our methodology for estimating demand response from two-part RTP.

A. Operational Costs

For Scenarios 12 and 13, we expect to incur certain information technology infrastructure costs that we have preliminarily estimated at $0.3 million for each scenario in costs codes C-3, C-4, C-10 and I-1. In addition, we expect to incur customer education and marketing costs for those customers taking advantage of the default two-part RTP rate schedules. For this preliminary analysis, we estimate these costs at $17.5 million for both scenarios in cost codes CU-10 and M-14.

As shown below in Table I-1, the only difference between Scenarios 12 and 13 pertain to expected customer acquisition costs for the rate incentives that would be paid to Rate Schedule I-6 customers. For this analysis, we forecast incentive costs of approximately $355.5 million.

Table I-1
Summary of Costs for Scenarios 12 and 13
(000s in 2004 Pre-Tax Present Value Dollars)

	Scenario 12	**Scenario 13**
Cost Categories	**Total**	**Total**
Metering System Infrastructure	$0	$0
Communications Infrastructure	0	0
Information Technology Infrastructure	327	327
Customer Service Systems	0	0
Management and Miscellaneous Other	17,500	17,500
Rate Incentives for Schedule I-6	0	355,500
TOTAL:	$17,827	$373,327

B. Benefits For Scenarios 12 and 13

Scenario 12 evaluates the demand response benefits of RTP for all large C&I customers above 200 kW. Scenario 13 evaluates the demand response benefits of RTP for all large C&I customers above 200 kW plus the reliability benefits of maintaining Schedule I-6 customers. We estimated a peak MW reduction using the following methodology and escalated that reduction per year based on customer growth for the class.

We applied the Commission's assumptions for capacity value of $85/kW-yr. A distribution loss factor of 8.4 percent was then applied to capacity benefits. We have not adjusted the above demand response benefits for Value of Service Loss to customers due to participation in TDRs. We believe such an adjustment would apply, however, we would require additional information about the actual RTP rates to employ our methodology. The results of our analysis of the benefits are shown in Table I-2 below.

Table I-2
Summary of Benefits for Scenario 12
(Millions in 2004 Pre-Tax Present Value Dollars)

	Scenario 12	**Scenario 13**
Benefit Categories	**Total**	**Total**
Systems Operations Benefits	$0	$0
Customer Service Benefits	$0	$0
Management and Other Benefits	$0	$0
Demand Response Benefit DR-1	$112	$382
Demand Response Benefit DR-2	$16	$53
TOTAL:	$128	$435

C. Uncertainty and Risk Analysis

No risk analysis of cost or operational benefit was performed for these scenarios as the costs and associated risks are relatively low given our knowledge of the existing system and that no incremental operational benefits were identified.

The load reductions from RTP are untested in recent years in SCE territory and therefore unknown. Also, we did not examine potential rate design issues associated with RTP. No market-based real-time prices exist in California so an RTP rate would have to be based on a proxy of market prices or actual real-time costs to the utility. We also do not know how customers would react to mandatory RTP. Current industry literature indicates that, while some large customers can adjust usage, others cannot.

D. Net Present Value Analysis

Table I-3 summarizes the Net Present Value results for Scenarios 12 and 13.

Table I-3
Summary of Cost/Benefit Analysis for Scenarios 12 and 13
($Millions)

	Costs	Benefits	Pre-Tax NPV
Scenario 12	$18	$128	$110
Scenario 13	$373	$435	$62

1. Methodology

This section describes how we developed an estimate of the MW savings at system peak from firm and interruptible customers who would potentially be on RTP rates. The July 21, 2004 Ruling required a business case analysis of two-part RTP rates but we were unable to perform such an analysis directly without additional guidance on a specific rate design and other factors. Consequently, CEC staff recommended that the utilities rely on prior studies on RTP implementation. Thus, our basic approach was to start with the results of the study that Christensen Associates performed for the California Energy Commission (CEC)[70] to estimate the statewide savings due to the potential implementation of RTP across the three major investor-owned utilities (IOUs) in the state. We applied those results, by Standard Industrial Classification (SIC) code, to the population of SCE customers with peak demands over 200 kW.

[70] Potential Impact of Real-Time Pricing in California, by Steve Braithwait and David Armstrong (Christensen Associates), January 14, 2004.

E. Description of the Christensen Report

The Christensen Report was based primarily on an analysis of Georgia Power's RTP program, serving about 1,600 large C&I customers. The analysis showed that the degree of price-responsiveness to RTP rates was related to SIC code. The report provides a list (Table 2 in the report) of 18 SIC codes that were found to be price responsive to some degree. For each SIC code, the report further disaggregated these groups into high, moderate, and low responders, and provided the percentage of Georgia Power customers that had each level of responsiveness for each SIC code. The report provided one elasticity parameter (the peak-period elasticity of substitution) for each responsiveness level for each SIC code.

Using statewide population information, PG&E's dynamic load profiles, historic rates, and historic "pre-energy crisis" wholesale costs, Christensen estimated the total statewide load savings at the system peak for each SIC code, for both a "very high price day" and a "high price day." The load savings by SIC code, both on an absolute and a percentage basis, is shown in table 4 of the report. Note that these savings (a total of 814 MW, or about 17 percent of the total load for the group on the very high price days) represent the expected statewide savings.

F. Determining Impacts on SCE's System Peak

In order to determine the impact on SCE's system peak from SCE's customers with peak demands over 200 kW, we first summarized the contribution to the system peak for these customers by SIC code and rate (including firm vs. interruptible). We then applied the percent load savings for each price-responsive SIC Code from Table 4 of the Christensen Report, using the very high price day information (in order to reflect the load likely to be dropped on extreme days), and totaled the load reductions across the SIC codes to estimate the total load reductions that SCE can expect if RTP tariffs are applied to all customers over 200 kW. Those SIC codes that were not listed in the report were not price responsive, so we assumed that there would be no load reduction by SCE customers in those SIC groups.

Most of the current SCE population of customers with demand over 200 kW already have interval data recorders, but some do not. Contribution to the 2003 system peak data were available for 10,585 of these customers, and 1,170 customers did not have interval data at that time. For the customers with interval data available, we used the actual contribution to the system peak hour. For those customers without interval data, we applied the rate class average coincidence factor for September 2003 to their September 2003 billing demand to estimate the contribution to the system peak hour. The actual demands and the estimated demands were then combined to provide results for the entire population of customers with demands over 200 kW.

We did not include agricultural customers in this analysis. We could not find evidence of agricultural customers being served on RTP rates anywhere in literature, so there was nothing upon which to base calculations.

We then split the SCE load for customers with peak demands over 200 kW into two groups, interruptible and firm, in order to estimate the load reduction if the firm customers were moved to the RTP Tariff and the interruptible customers were left on their current interruptible rates. This required making a few additional assumptions. The first was that the interruptible customers would be in the high responding part of each SIC code group. This was based on the fact that they were already curtailing a significant amount of load when called to do so, so they were certainly capable of responding. The interruptible load for some of the SIC code groups was more than the percent of high responders from the Christensen report, so in those cases, we assumed that all of the high responders in the SIC group were interruptible, and part of the moderate responders were interruptible as well.

G. Determining Load Reductions by SIC Group

The Christensen Report did not provide the load reductions by response level either in the aggregate or for individual SIC code groups. Thus, we made one additional assumption. Because the Christensen Report did provide the peak-period elasticity of substitution for each response level within each SIC code group, we made the simplifying assumption that the load reductions in the high and moderate responding groups were proportional to the peak-period elasticity of substitution for the groups. Based on the Georgia Power results, the elasticity in low responding groups is zero. Therefore we assume that there is no load response among this group. As such, there is enough information to allocate the load response by SIC code group to the high and moderate responders. The assumptions used are described in the following three equations:

$$totpctsavings = pctsavings_h \cdot pct_h + pctsavings_m \cdot pct_m + pctsavings_l \cdot pct_l$$
$$\frac{pctsavings_h}{pctsavings_m} = const = \frac{elasticity_h}{elasticity_m}$$
$$pctsavings_l = 0$$

In this formula, "*totpctsavings*" is the total savings for the SIC code group, expressed as a percent, "*pct*" is the percent in the SIC group for each response level, "*const*" is the ratio of the high responder elasticity parameter to the moderate responder elasticity parameter for the SIC group, "*elasticity*" is the elasticity parameter, and "*pctsavings*" is the estimated percent savings for each response level. The subscripts indicate the response level of high, moderate, or low.

Based on these relationships, for each SIC code group, we estimated the percent reduction by response level for the moderate and high responding groups as follows.

$$totpctsavings = const \cdot pctsavings_m \cdot pct_h + pctsavings_m \cdot pct_m + 0 \cdot pct_l$$
$$pctsavings_m = \frac{totpctsavings}{(const \cdot pct_h + pct_m)}$$
$$pctsavings_h = const \cdot pctsavings_m$$

Once the percentage reductions for each SIC group was estimated in this way, we applied those percentage reductions to both the interruptible and firm loads for each SIC group and each response level. We then aggregated the firm loads together and the interruptible loads together, to get total estimated reductions from each group.

Appendix J

Value of Service Loss Description

APPENDIX J

VALUE OF SERVICE LOSS DESCRIPTION

This appendix describes the method we used to estimate the value of the loss of service as described in this volume from all the ratepayer perspective. We used the Standard Practice Manual's (SPM) definition of the all-ratepayer or societal perspective as a measure of overall economic efficiency. The participant and other ratepayer perspectives address the distributional (cost shifting) impacts of a program. The participant perspective can also be helpful in the design of appropriate incentives. The SPM participant perspectives can be expressed as follows in Table J-1:

Table J-1
Standard Practice Manual Perspectives

	Participant Perspective	Other Ratepayer Perspective	All Ratepayer Or Societal Perspective
Benefits	Bill Savings	Resource Cost Savings Operational Savings Metering Charge Revenues	Resource Cost Savings Operational Savings
Costs	Value of Service Loss Metering Charges	Participant Bill Savings AMI Costs DR/DP Admin Costs	AMI Costs DR/DP Admin Costs Value of Service Loss

SCE used this analytical framework for evaluating advanced metering infrastructure investments.

A. Description of the Estimating Method

We have presented the required full and partial deployment final business case analyses set forth using the "all ratepayer" perspective, in order to emphasize economic efficiency. Cases are presented both with and without customer value of service loss to show the effect that this variable has on the analysis results. Consideration of distributional impacts is better addressed in the design of individual pricing demand response programs. It should be noted, however, that because these programs improve the accuracy of price signals which customers receive, any distributional impacts will, in general, reduce the level of cross-subsidy imbedded in current rate designs.

B. Calculation of Value of Loss of Service

Value of service loss can be calculated based on information on customers' response to dynamic pricing derived from the recent pilot studies. Consider a situation where the price of energy in a peak period, increases from a flat-rate of 15 cents to a "real time price" of 25 cents as a result of a dynamic pricing program, and a customer reduces monthly consumption by 100 kWh as a result. We know from this behavior response that the customer values the use of this electricity by a minimum of 15 cents, but less than 25 cents. If the customers' demand response is linear (straight line) then the average value that the customer would have received from the 100 kWh reduced usage is 20 cents, the simple average of the flat rate and real time price. Therefore, we can infer a value of $20 to the foregone consumption (20 cents times 100 kWh).

This approach is consistent with the economics literature addressing time of use and real-time pricing. Acton and Bridger,[71] and Borenstein, Jaske and Rosenfeld,[72] discuss a general societal welfare (benefit) analysis that includes customer value of service impacts. The resultant change in social welfare from a change in pricing strategy from flat rate to time of use or real time rate is shown by the equation:

$$\Delta \text{ Societal Benefit} = -\tfrac{1}{2}\Delta P_1 \Delta Q_1 - \tfrac{1}{2}\Delta P_2 \Delta Q_2$$

The ΔPs represent the change in prices and the ΔQs represent the change in quantity. This formula is based on two time periods, but generalizes to any number of periods. Because price and quantity change move in opposite directions (an increase in price decreases usage), overall societal benefit is increased by moving to time-of-use or real time pricing. Using

71 Acton, Jan Paul and Bridger M Mitchell. "Welfare Analysis and Electricity Rate Changes," The Rand Foundation Note # N-2010-HF/FF/NSF, May 1983.

72 Borenstein, Severin, Michael Jaske, and Arthur Rosenfeld. "Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets", University of California Energy Institute, Center for the Study of Energy Markets, October 2002, CSEM Working Paper # 105.

similar nomenclature, where P_1 and P_2 are the time-of-use or real time prices, resource cost savings and value of service loss can be expressed as follows:

□ Resource Cost Savings = $-P_1$ □ Q_1 - P_2 □ Q_2

□ Value of Service Loss = - (P_1 - ½ □ P_1□ □ Q_1) - (P_2 - ½ □ P_2□ □ Q_2)

Given that the objective of time of use or real time pricing is to set rates equal to incremental resource costs associated with consumption, the change in resource costs is given by $P\Delta Q$. Value of service loss is calculated as described above, the average of flat rate and time of use prices times the change in quantity. Subtracting value of service loss from resource cost savings results in the equation for societal benefit shown above.

C. Results of Calculation

The values that result from the calculation method above for Scenarios 4 and 17 are contained in the following table.

Table J-2
Value of Service Analysis Impacts on Demand Response Benefits by Business Case Scenario
($2004 Present Value in Millions)

(1)	(2)	(3)	(4)=(2)+(3)	(5)	(6)	(7)=(5)+(6)-(4)
Scenario	**Value of Service Loss - On-Peak**	**Value of Service Benefit - Off-Peak**	**Net Value of Service Loss Effect**	**DR-1 Benefit**	**DR-2 Benefit**	**Impact = DR-1 + DR-2 - Net Value of Service Effect**
4	$173.5	($30.0)	$143.5	$325.7	$41.0	$223.2
17	$14.8	(4.3)	$10.5	$38.1	$4.8	$32.4

Appendix K

Rate Design and Bill Impact Analysis

APPENDIX K

RATE DESIGN AND BILL IMPACT ANALYSIS

This Appendix describes the processes we could employ to design the experimental/existing CPP rate structures and also describes our approach to, and results of our analysis of, bill impacts expected from these experimental CPP rate structures both in a longer-term, post-AB1X environment (with a variety of usage reductions) and a short-term AB1X-compliant environment, without meter charges. While a wide variety of rate design and billing impacts could be constructed, these two circumstances represent the relevant spectrum of these analyses.

A. Rate Design Process in a Longer Term non-AB1X Environment

1. Domestic (Residential) Rate Design Process

Two sets of residential rates were developed for the AMI business case scenarios to be revenue neutral to the Schedule D energy charges. No changes were made to customer charges. AMI residential rates are based on a six-month summer, and six-month winter season, consistent with the existing SPP experimental rate structures, with the exception of CPP-P, which is an overlay of existing residential tiered rate structure with a four-month summer, and eight-month winter season.

A default two-part D-TOU-2 rate was developed with an on-peak period of 2:00 p.m. to 7:00 p.m., summer and winter weekdays, and all other hours as off-peak. This structure is consistent with existing experimental SPP time periods, and is used as the basis for CPP-F and CPP-V rate design. All rates were constructed to be revenue neutral to Schedule D, assuming no load alterations. Two sets of residential rates were constructed for analytical purposes; the first compliant with AB1X provisions, and the second ignoring the AB1X restrictions. In the non-AB1X compliant rates, the TOU rates along with their CPP components would be more clearly understood by customers since they would understand exactly what the cost of electricity is at any point in time. Designing rates compliant with AB1X restrictions with usage below 130 percent of baseline not subject to CPP or TOU pricing and usage above 130 percent of baseline subject to dynamic pricing would be extremely confusing to customers as it would be difficult for a medium-usage customer to respond to CPP prices if only a pro-rated portion of its above-baseline consumption were subject to the CPP rate. Customers using less than their baseline allowance would never actually be charged the CPP rate, which would eliminate any demand response contributions they could make. During the 12-month period ending April 2004, 74 percent of SCE's residential customers' usage was billed at or below 130 percent of baseline (Tiers 1 and Tier 2). In fact, about 34 percent of residential customers never exceeded their Tier 2 usage levels, meaning a significant portion of customers would be exempt from participating in CPP rates in an AB1X compliant case.

For both sets of rates, the existing D-TOU-2 rate option[73] is used as a basis for TOU rate design. The CPP Event rate was based on the D-TOU-2 summer, on-peak energy rate, plus an approximate $1.1333 per kWh ($85 prescribed avoided peak demand cost divided by 75 hours) adder. Because this CPP peak rate is significantly above the CPP Pilot rate, it established the cap on the CPP rate (even though the reduced number of CPP hours assumed in the CPP-V rate would demand an even higher CPP rate using the same methodology).

The D-TOU-CPP-F rate was modeled after the existing experimental TOU-D-CPP-F rate and assumes 12 Summer Peak days and 3 Winter Peak days at five hours per CPP Event day, for a total of 75 CPP hours annually. The D-TOU-CPP-V rate was also modeled after the existing experimental TOU-D-CPP-F rate

[73] D-TOU-2 is a modified form of TOU-D-1 to account for variations of seasonal and peak period designations.

using 12 Summer Peak days and three Winter Peak days with only 3 hours per CPP Event between the hours of 2:00 p.m. to 5:00 p.m., for a total of 45 CPP hours annually. The D-TOU-CPP-P rate used the basic tiered residential rate with a CPP adder based on 12 Summer Peak days and 3 Winter Peak days at 5 hours per CPP Event, for a total of 75 CPP hours annually. In all scenarios, the added revenue resulting from high priced CPP events reduces the remaining non-CPP rate levels to maintain revenue neutrality.

2. GS-1 Rate Design Process

All Small Commercial customers' rates for the AMI business case scenarios were developed revenue neutral to the Schedule GS-1 energy charges. No changes were made to customer charges. These rates are based on a four-month summer, and eight-month winter season, consistent with the existing CPP experimental rate structures.

A default two-part GS-1-TOU-2 rate was developed with an on-peak period of noon to 6:00 p.m., summer and winter weekdays, and all other hours as off-peak. This structure is consistent with existing experimental CPP time periods. This default rate was constructed revenue neutral to the existing GS-1 rate, and used the existing GS-1-TOU option as a basis for TOU rate design.

The CPP Event rate was based on the summer on-peak energy rate, plus a $0.9444 per kWh ($85 divided by 90 hours) adder. Similar to the residential rate structures, this CPP event rate is used for GS-1-CPP-F and GS-1-CPP-V, and GS-1-CPP-P rate schedules. GS-1-CPP-F was modeled after the existing experimental GS-1-CPPV rate using 12 Summer Peak days and 3 Winter Peak days at 6 hours per CPP Event, for a total of 90 CPP hours annually.

GS-1-CPP-V was modeled after the existing experimental GS-1-CPPV rate, based on 12 Summer Peak days and 3 Winter Peak days with 3 hours per CPP

Event between the hours of 2:00 p.m. to 5:00 p.m., for a total of 45 CPP hours annually.

GS-1-CPP-P was based on 12 Summer Peak days and three Winter Peak days at 6 hours per CPP Event, for a total of 90 CPP event hours annually. To preserve revenue neutrality, the added revenue resulting from CPP events resulted in a reduction to the otherwise application tariff (OAT) energy charges.

3. GS-2 Rate Design Process

All Medium Commercial customers' rates for the AMI business case scenarios were developed revenue neutral to schedule GS-2 energy charges. No changes were made to the demand or fixed charges. These rates are based on a four-month summer and eight-month winter season, consistent with existing GS-2-CPP rate structure but with the additional allowance of CPP events occurring in the winter season.

The existing (revenue neutral) GS-2-TOU rate option is used as the TOU default, thus no default two-period TOU rate structure was developed for this rate class. The CPP Event rate is based on the GS-2-TOU summer on-peak energy rate, plus a $0.9444 per kWh ($85 divided by 90 hours) adder. The resulting CPP event rate is used for GS-2-CPP-F, GS-2-CPP-V, and GS-2-CPP-P rate schedules.

GS-2-CPP-F is modeled after the existing GS-2-CPP rate, with the exception of adding winter CPP events, and includes 12 Summer Peak days and three Winter Peak days at 6 hours per CPP Event, for a total of 90 CPP hours annually. GS-2-CPP-V is modeled after the existing GS-2-CPP rate using 12 Summer Peak days and 3 Winter Peak days at 3 hours per CPP Event between the hours of 2:00 p.m. to 5:00 p.m., for a total of 45 CPP hours annually. GS-2-CPP-P is based on 12 Summer Peak days and 3 Winter Peak days at 6 hours per CPP Event, for a total of 90 CPP hours annually. The added revenue resulting from CPP events at the CPP rate was offset by a fixed percentage reduction to the other GS-2-TOU energy charges.

Rates used in the business case analysis are:

Table K-1
Rates Structure for Preliminary Analysis

DOMESTIC			
D-TOU-2-Basis		Rate	
Summer	On	0.28026	<<= 6 Month, 2pm-7pm On-Peak
	Off	0.11566	
Winter	On	0.13133	<<= 6 Month, 2pm-7pm On-Peak
	Off	0.1099	
CPP-F		Rate	
CPP Event			
Summer	On	1.41359	<< = 12 Summer Top Peak Days @ 5 hours/Day, 2 pm-7 pm
Winter	On	1.41359	<< = 3 Winter Top Peak Days @ 5 hours/Day, 2 pm-7 pm
Non-CPP Event			
Summer	On	0.22816	
	Off	0.09416	
Winter	On	0.11864	
	Off	0.09928	
CPP-Pure			
CPP Event		Rate	
Summer	On	1.41359	
Winter	On	1.41359	
CPP-V			
CPP Event		Rate	
Summer	On	1.41359	<< = 12 Summer Top Peak Days @ 3 hours/Day, 2 pm-5 pm
Winter	On	1.41359	<< = 3 Winter Top Peak Days @ 3 hours/Day, 2 pm- 5 pm
Non-CPP Event			
Summer	On	0.24991	
	Off	0.10313	
Winter	On	0.12413	
	Off	0.10388	
GS-1			

GS-1-TOU-2-Default		Rate	
Summer	On	0.34731	<<= 4 Month, Noon-6pm On-Peak
	Off	0.10982	
Winter	On	0.11614	<<=8 Month, Noon-6pm On-Peak
	Off	0.10706	
CPP-F			
CPP Event		Rate	
Summer	On	1.28731	<< = 12 Summer Top Peak Days @ 6 hours/Day
Winter	On	1.28731	<< = 3 Winter Top Peak Days @ 6 hours/Day
Non-CPP Event			
Summer	On	0.28254	
	Off	0.08934	
Winter	On	0.10478	
	Off	0.09658	
CPP-Pure			
CPP Event		Rate	
Summer	On	1.28731	
Winter	On	1.28731	
CPP-V			
CPP Event		Rate	
Summer	On	1.28731	<< = 12 Summer Top Peak Days @ 3 hours/Day, 2 pm-5 pm
Winter	On	1.28731	<< = 3 Winter Top Peak Days @ 3 hours/Day, 2 pm - 5pm
Non-CPP Event			
Summer	On	0.31511	
	Off	0.09964	
Winter	On	0.11069	
	Off	0.10203	
GS-2			
GS-2-TOU-2-Option/OAT		Rate	
Summer	On	0.12796	
	Mid	0.09435	
	Off	0.08484	
Winter	Mid	0.09921	
	Off	0.08484	
CPP-F		Rate	
CPP Event			
Summer	Noon-6pm	1.06796	<< = 12 Summer Top Peak Days @ 6 hours/Day

Winter	Noon-6pm	1.06796	<< = 3 Winter Top Peak Days @ 6 hours/Day
Non-CPP Event			
Summer	On	0.10463	
	Mid	0.07715	
	Off	0.06937	
Winter	Mid	0.08285	
	Off	0.07085	
CPP-Pure			
CPP Event		Rate	
Summer	On	1.06796	
Winter	On	1.06796	
CPP-V		Rate	
CPP Event			
Summer	Noon-6pm	1.06796	<< = 12 Summer Top Peak Days @ 3 hours/Day
Winter	Noon-6pm	1.06796	<< = 3 Winter Top Peak Days @ 3 hours/Day
Non-CPP Event			
Summer	On	0.11646	
	Mid	0.08587	
	Off	0.07722	
Winter	Mid	0.09127	
	Off	0.07805	

B. Bill Impact Analysis in a Longer-Term Non-AB1X Environment

1. Residential Bill Impacts

Residential bill impacts, which are incorporated into the MMI simulation tool, provided the basis for estimating customer adoption rates for TDRs in certain AMI opt-in scenarios.[74] Additionally, an understanding of bill impacts is necessary to gauge future program success.

As part of the revenue neutrality component in the rate design process, SCE computed average bills for each of the nearly 3,300 customers in its load

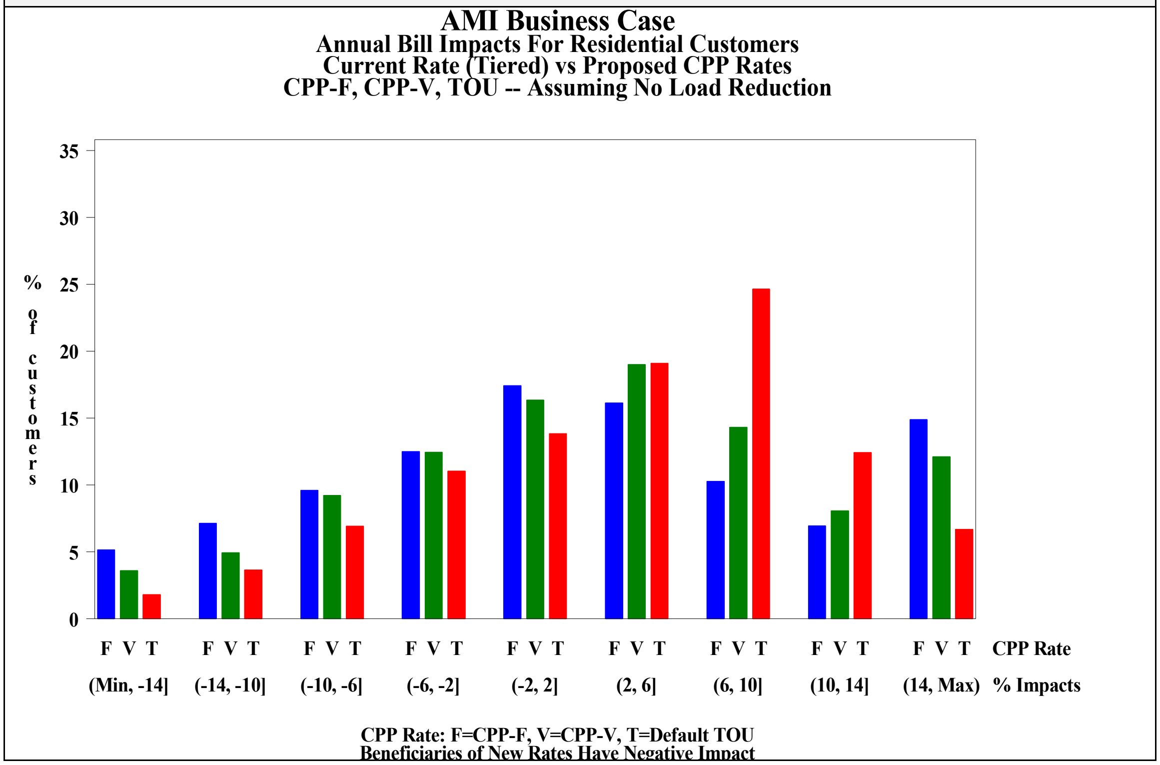
[74] These do not include Scenarios 4 and 17, which were opt-out scenarios.

research residential rate group sample. After applying the relevant sampling weights, rates were scaled to insure that the total bills recovered the same revenue for each customer class. The larger load research sample was used instead of the SPP sample data to gauge these impacts through the use of a larger sample size and to eliminate any impact of participation bias.

Figure K-1 below displays the distribution of bill impacts for the CPP-F, CPP-V, and TOU rates versus the current tiered Domestic rate for the residential customer class assuming no price-induced demand response. Although the revenue-neutral rate design arithmetically centers the distribution around zero, the relatively wide distribution of bill impacts is brought about by a more equitable cost allocation by the CPP rate structures in two ways. First, the elimination of AB1X price cap results in low usage customers experiencing the largest percentage bill increases. Most of the nearly 15 percent of customers experiencing an annual bill increase of at least 14 percent are lower usage customers (see Table K-2). Second, those customers residing in the hotter weather zones using higher amounts of high cost summer on-peak energy also see bills commensurate with their (higher) cost (see Table K-3).

Table K-2
Residential Bill Impacts - Tiered vs. CPP-F -Percentage Distribution of Accounts by Average Monthly Usage and Percent of Bill Impact

Figure K-1
Annual Bill Impacts for Residential Customers – Assuming No Load Reductions



Average Monthly Usage	(Min, -14]	(-14, -10]	(-10, -6]	(-6, -2]	(-2, 2]	(2, 6]	(6, 10]	(10, 14]	(14, Max)	Total
0 - 400 kWh	0.5	1.2	1.	4.	10.1	10.9	6.1	3.0	6.3	44.9
401 - 800 kWh	1.6	4.0	5.	5.	5.	3.	3.2	3.1	7.6	39.1
> 800 kWh	3.1	2.0	2.	2.	2.	1.	1.0	0.8	1.0	16.1

Note: Positive bill impacts indicate a higher CPP-F bill relative to the tiered OAT.

Table K-3
Residential Bill Impacts Tiered vs. CPP-F
Percentage Distribution of Accounts by Climate Zone and Percent of Bill Impact

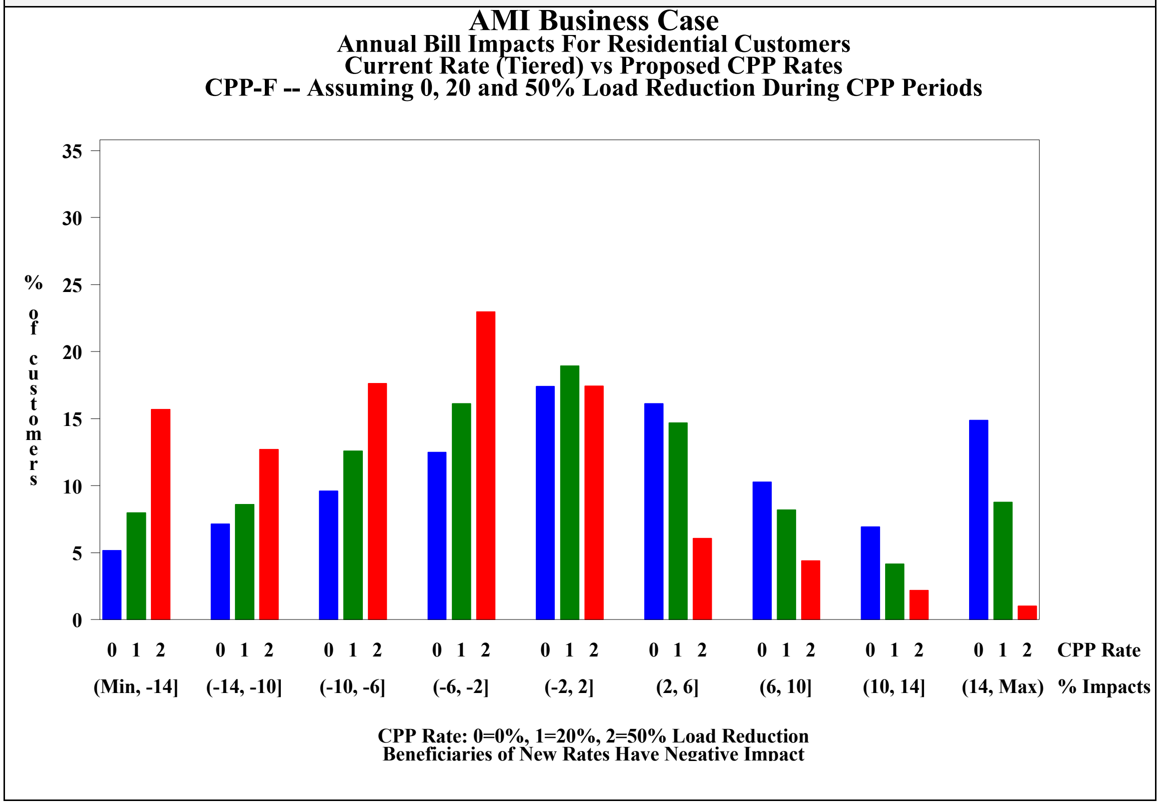
Climate Zone	(Min, -14)	(-14, -10]	(-10, -6]	(-6, -2]	(-2, 2]	(2, 6]	(6, 10]	(10, 14]	(14, Max)	Total
2	3.5	4.7	4.9	6.9	9.1	8.5	4.1	1.4	1.5	44.7
3	1.2	2.2	3.8	4.7	7.1	6.4	5.0	4.8	11.3	46.5
4	0.4	0.2	0.9	0.9	1.2	1.2	1.2	0.7	2.0	8.8
Total	5.2	7.1	9.6	12.5	17.4	16.1	10.3	6.9	14.9	100.0

Note: Positive bill impacts indicate a higher CPP-F bill relative to the tiered OAT.

Overall, the TOU and CPP-F rates shift about six to eight percent of the overall revenue burden from the winter season into the summer season, respectively. This type of revenue/cost shift can be accomplished with the existing metering via seasonal energy charges though the peak demand impact of such a seasonal revenue allocation shift would need to be explored. The cost/benefit associated with this option would prove valuable as incremental cost would be negligible and there would almost surely be some demand response benefits.

Figure K-2 below displays three annual bill impact distributions (CPP-F non AB1X compliant versus their tiered OAT rate) for the residential population assuming three different levels of load reduction (0%, 20%, and 50%) for all customers billed on a CPP-F rate. For simplicity, no load shifting was assumed nor were rates re-calibrated to preserve revenue neutrality. Without any load reduction during CPP events, the number of customers experiencing at least a 10 percent annual bill increase is above 22 percent. The most striking component of the bill impact analysis is that the lowest usage customers whose bills would otherwise be frozen by the provisions of AB1-X would see significant bill increases. At the 20 percent load reduction level, typical of the maximum load reductions seen in the SPP pilot, about 13 percent of residential customers still see bill increases of more than 10 percent, while only about 16 percent of our customers would see an annual bill decrease of at least 10 percent.

Figure K-2
Annual Bill Impacts for Residential Customers – Assuming Load Reductions During CPP-F Periods

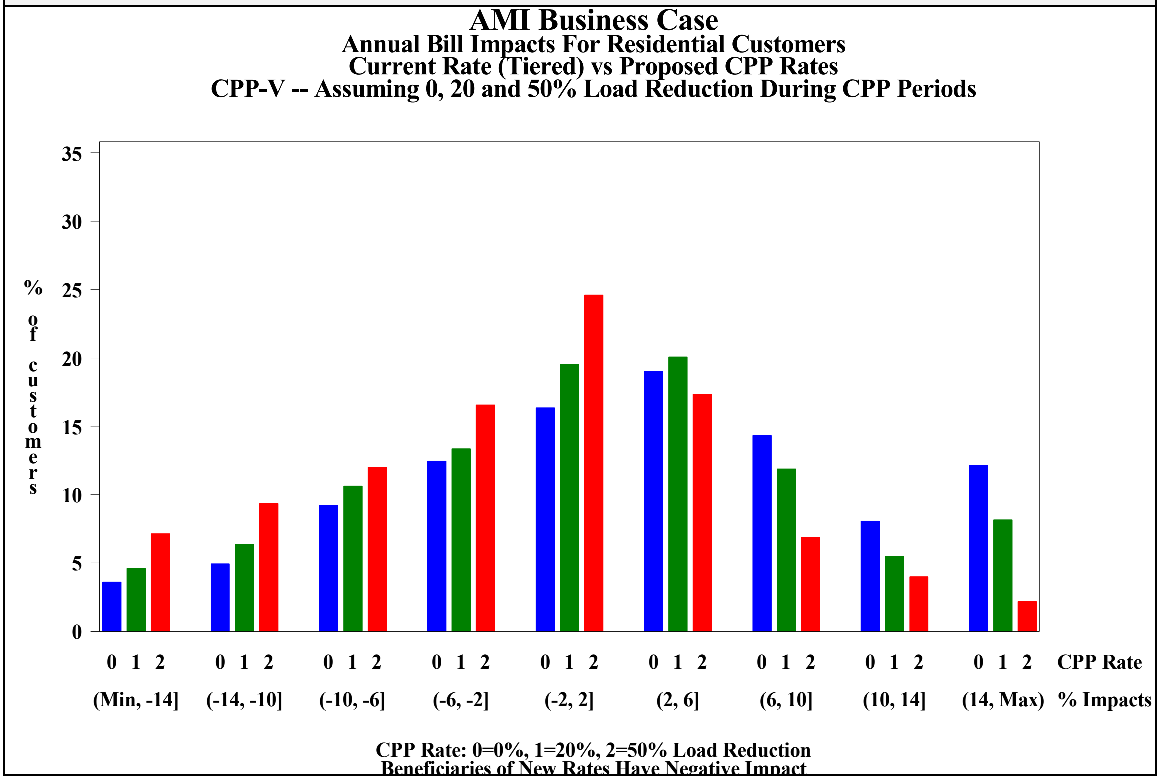


The risk associated with such distributions is that if customers save such small amounts or even see bill increases, while making significant efforts to alter their behavior, they could likely become disillusioned with the program. The cause of this low bill impact despite rather large demand response is that the number of hours designated as CPP periods represents less than one percent of the total hours of energy consumption in the year (75 CPP hours versus 8760 total hours/year). While the CPP rates designed for this application have even a higher ratio to otherwise applicable on-peak rates (at a 6:1 ratio) versus the CPP-Pilot rates, customer bill reductions remain relatively small in spite of significant customer response. It is exactly this type of minimal billing impact despite significant load shifting/reduction that led to the demise of Puget Sound Electric's system-wide TOU deployment. Despite customer response, low bill reductions to those who responded and bill increases associated with the TOU meter cost (at a relatively modest $1/month) led to overall bill *increases* that caused such customer backlash that Puget Sound Energy cancelled the program after less than two years.[75]

Exit interviews of SPP participants will prove valuable at the end of the SPP pilot to gauge ongoing interest and cost savings relative to the effort required to achieve those savings. It is only when customers shed 50 percent of their load during the CPP periods (an extremely unlikely case especially for low usage customers) do significant cost reductions occur (though still not in all cases). In general, the most significant discretionary load capable of providing such a large reduction in load is air-conditioning equipment. It is this overlap that makes us believe that focus on the ALC program is the best alternative for providing cost effective price-induced demand response. Figure K-3 displays similar information using the CPP-V rate design.

[75] Williamson, Craig, "Primen Perspective: Puget Sound Energy and Residential Time-of-Use Rates – What Happened?" Energy Use Series, Volume 1, Issue 10, December 2002.

Figure K-3
Annual Bill Impacts For Residential Customers – Assuming Load Reductions During CPP-V Periods

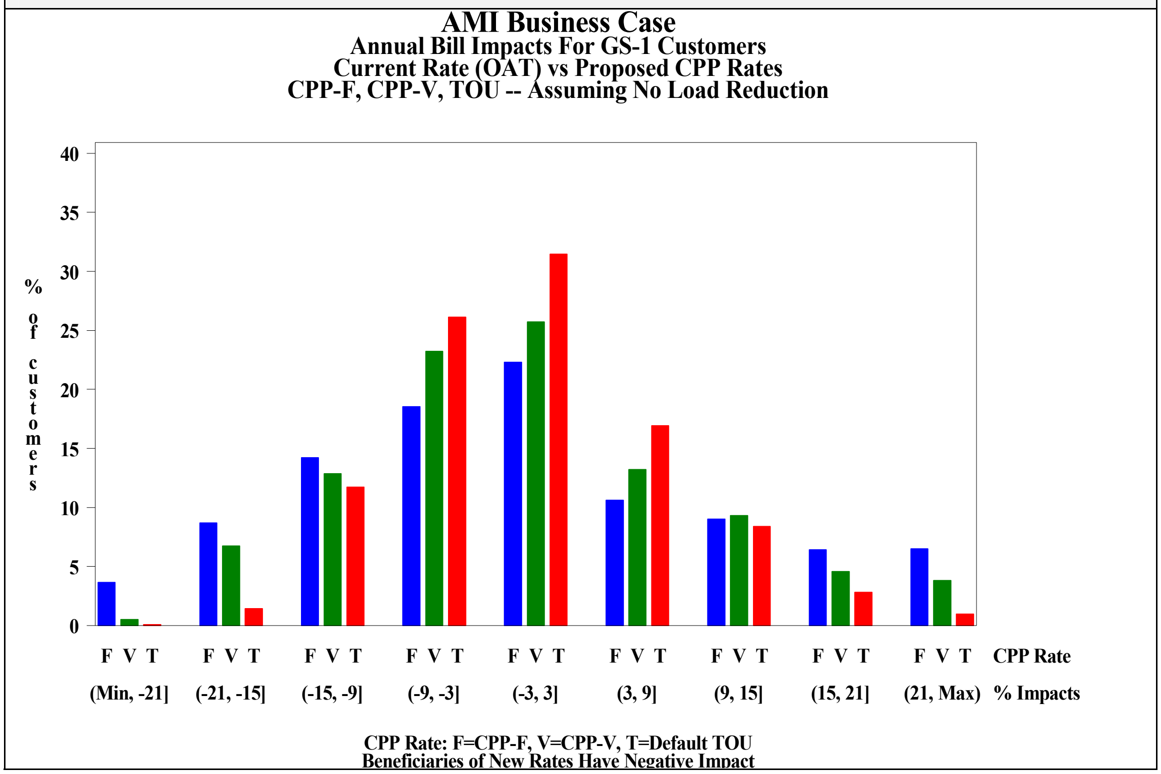


2. Commercial Bill Impacts

As part of the revenue neutrality component in the rate design process, SCE computed average bills for each of the 3,100 and 3,500 customers in its GS-1 and GS-2 load research rate group samples. After applying the relevant sampling weights, rates were scaled to insure that the total bills recovered the same revenue for each customer class. The large load research samples were used instead of the SPP sample data to gauge these impacts due to their larger sample sizes and to eliminate any impacts of participation bias.

Figure K-4 displays bill impact distributions for the small commercial (GS-1) population for the CPP-F, CPP-V, and TOU rate schedules relative to the current GS-1 rate. Again, no load shifting as a result of price response was assumed here. While all three distributions center around zero, under the CPP-F program, about 25 percent of GS-1 customers will experience an annual bill increase of at least nine percent, while about 20 percent of the GS-1 population will experience a bill decrease of at least nine percent due to the more precise cost allocation nature of these rates versus a rate with only seasonal energy charges. The CPP-V and TOU bill impacts have narrower dispersions.

Figure K-4
Annual Bill Impacts for GS-1 Customers –
Assuming No Load Reduction



Figures K-5 and K-6 display bill impact distributions (CPP-F and CPP-V versus their OAT) for the GS-1 populations assuming three different levels of load reduction (0%, 20%, and 50%) for all customers during CPP periods. Load reductions associated with businesses are generally less than residential customers, making the 20 percent and 50 percent cases that much more unlikely (except perhaps in such instances where the utility directly controls the customer's load).

The GS-1 and GS-2 bill impact distributions display similar results to the residential population.

Figure K-5
Annual Bill Impacts for GS-1 Customers –
Assuming Load Reductions During CPP-F Periods

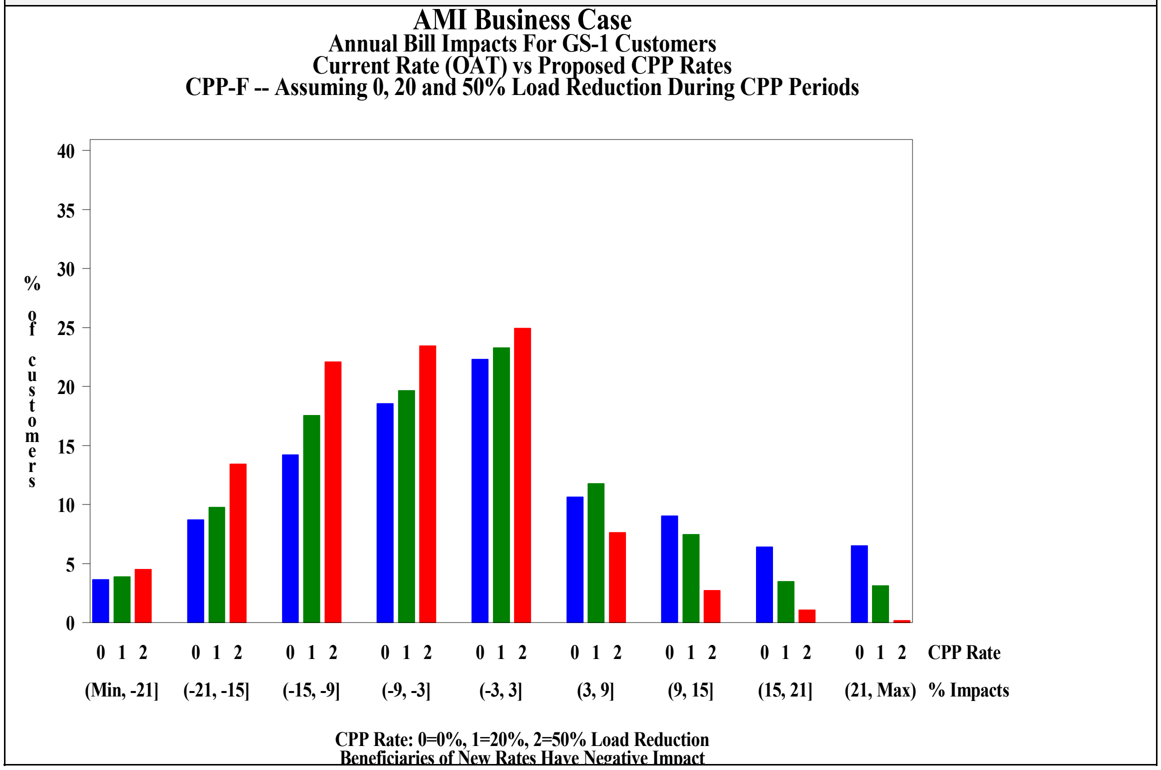


Figure K-6
Annual Bill Impacts for GS-1 Customers – Assuming Load Reductions During CPP-V Periods

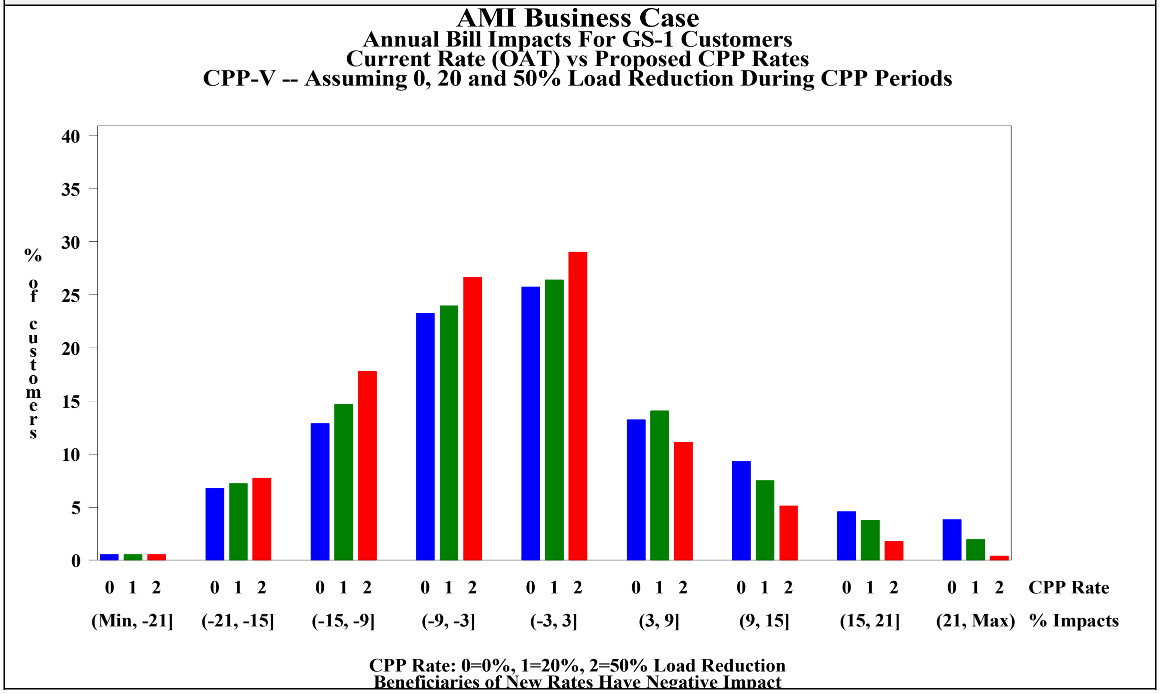


Figure K-7 displays bill impact distributions for the medium commercial (GS-2) population for the CPP-F, CPP-V, CPP-P and TOU rate schedules relative to the current GS-2 rate. Again, no load shifting as a result of price response was assumed here. Compared to the GS-1 bill impact distributions, the GS-2 distributions are somewhat less dispersed as a significant portion of the rate group's total revenue is recovered via demand charges. For these rates, all demand charges were set to equal the existing GS-2 rate constraining the differences between the rates to energy charges. Figures K-8 and K-9 show that the largest bill impacts occur when customers shift 50 percent of their energy consumption out of CPP-F and CPP-V periods. The magnitude of the bill impacts, under the 20 percent reduction scenarios is somewhat subdued as only about 11 percent of these customers realize an annual bill reduction of nine percent or more.

Figure K-7
Annual Bill Impacts for GS-2 Customers – Assuming No Load Reduction

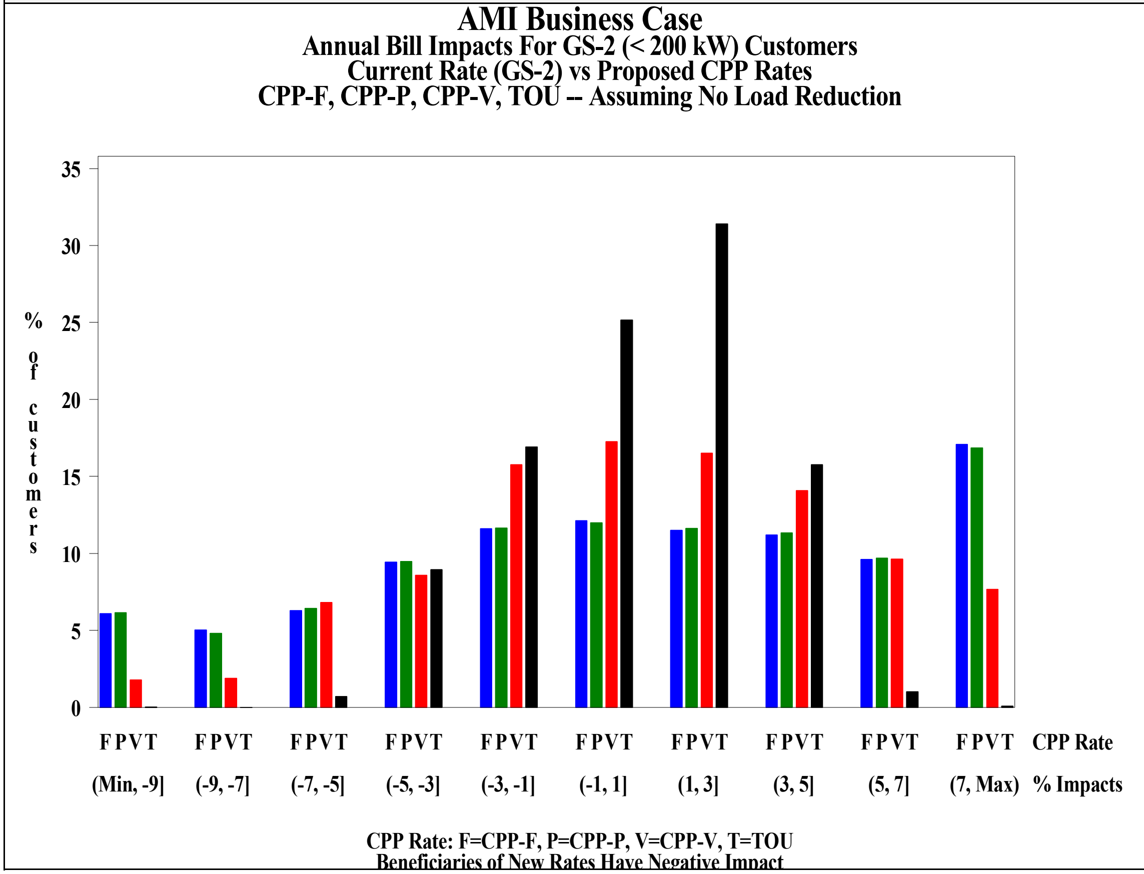
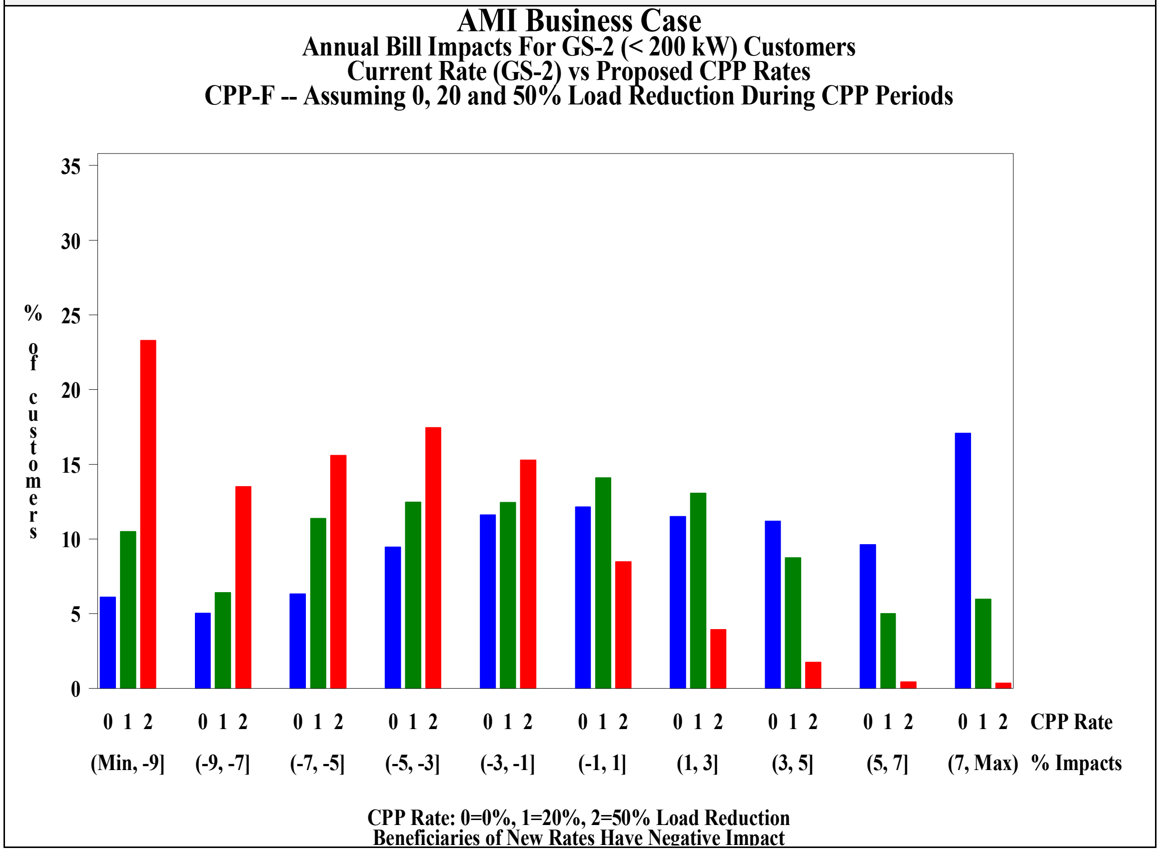
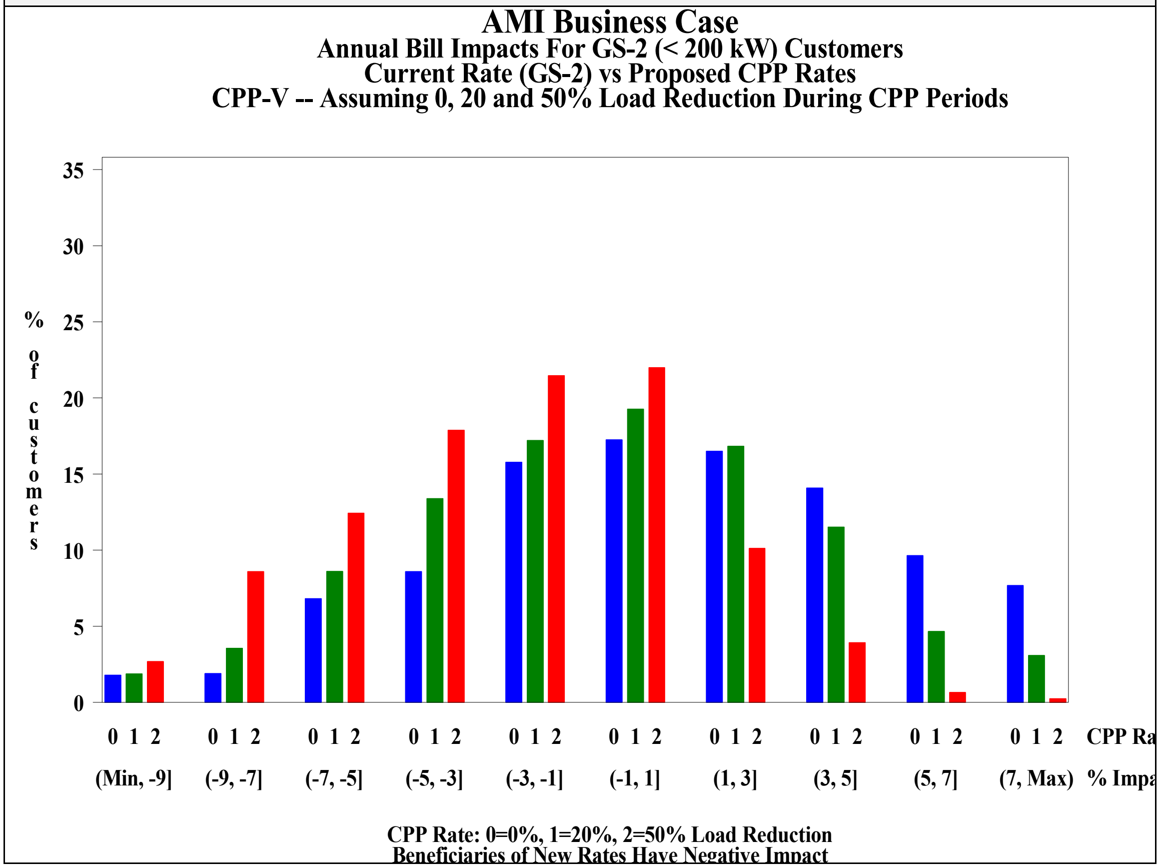


Figure K-8
Annual Bill Impacts for GS-2 Customers – Assuming Load Reductions During CPP-F Periods



1

Figure K-9
Annual Bill Impacts for GS-2 Customers –
Assuming Load Reductions During CPP-V Periods



C. Rate Design and Bill Impact Analysis in a Short-Term AB1X Environment

This section presents illustrative revenue allocation and rate design proposals for recovery of SCE's annual AMI revenue requirements under an "operations-only" business case assumption (*i.e.* no change in customer usage patterns) and an AB1X compliant rate design. SCE forecasts positive net-AMI revenue requirements for both the full-deployment and partial deployment cases. AMI infrastructure and O&M related costs authorized for recovery would be credited to the appropriate distribution balancing account for ultimate recovery through distribution rates. SCE presents system and rate group average impacts for both the full- and partial deployment scenarios (Scenarios 4 and 17, respectively) in an AB1X compliant rate design. Analyses provided earlier in this Appendix presented the range of billing impacts in a non-AB1X compliant structure under a wide variety of demand responses. Unlike the bill impacts presented previously in this Appendix, the short-term AB1X environment discussed below assumes no demand response under a purely operational scenario and simply includes the rate effects of capital recovery and net operational impacts as part of a distribution rate adder.

1. Allocation of Net-AMI Revenue Requirement

Excluding any benefits from energy procurement due to assumed unchanging customer usage patterns, the cumulative net AMI-related revenue requirements for the full- and partial deployment Scenarios 4 and 17 without procurement benefits are forecasted at $1.329 billion and $173 million, respectively. For illustrative purposes, SCE proposes to allocate a levelized annual revenue requirement for both scenarios to rate groups based on distribution revenues as determined in SCE's 2003 GRC. The allocated net-AMI revenue requirement for Scenarios 4 and 17 of $174.0 million and $22.7 million, on a levelized annual basis, represents about 1.7 percent and 0.2 percent of SCE's total revenue requirement. However, because distribution revenue requirement is allocated to rate groups based on distribution marginal cost, the percentage impact to individual rate groups will vary. In addition, the impact of distribution rate increases on residential customers will fall disproportionately to higher usage customers as a result of restrictions under AB1X. Monthly customer charges and Tier 1 and Tier 2 energy charges for up to 130 percent of baseline consumption are capped at levels in effect as of February 2001.

2. Distribution Rate Design and Average Bill Impacts

SCE proposes to adjust the distribution component of retail Delivery charges based on the system average percentage change (SAPC) basis in Distribution revenue resulting under each of the scenarios being analyzed. This approach is consistent with SCE's methodology for incorporating Distribution revenue changes in recent Commission decisions in phase 1 of SCE's 2003 GRC and 2004-2005 ERRA. Because current distribution rates reflect the revenue allocations included in the Settlement Agreement in phase 2 of SCE's 2003 GRC, adopted by the Commission in Decision (D.) 05-03-022, scaling distribution rates on a SAPC basis maintains the authorized level of distribution revenue allocation. Tables K-4 through K-7 show the illustrative rate group total revenue requirement and average rate percentage impacts of the distribution revenue requirement increases under SCE's full- and partial AMI deployment scenarios, for bundled service and Direct Access (DA) customers. Although bundled service and DA customers pay the same charges for Delivery service, the percentage impact to class average DA rates is greater, because distribution makes up a larger percentage of the DA customer bill.

Table K-4
Illustrative Bill Impact Analysis
Domestic Service – AB1X Restrictions

	Monthly Usage Level - Summer kWh					
	200	500	750	1000	1500	2000
Current Rate	$ 24.62	$ 64.48	$ 108.15	$ 154.94	$ 248.44	$ 342.12
Scenario #4	$ 24.62	$ 64.91	$ 110.97	$ 160.16	$ 258.42	$ 356.90
Scenario #17	$ 24.62	$ 64.53	$ 108.52	$ 155.62	$ 249.74	$ 344.06
Total Summer Bill Impact						
Scenario #4	$ -	$ 1.72	$ 11.29	$ 20.86	$ 39.94	$ 59.12
Scenario #17	$ -	$ 0.23	$ 1.48	$ 2.73	$ 5.23	$ 7.74
# Monthly Bills	14.6%	39.1%	18.7%	10.6%	10.6%	6.4%

	Monthly Usage Level - Winter kWh					
	200	500	750	1000	1500	2000
Current Rate	$ 24.62	$ 67.66	$ 112.90	$ 159.69	$ 253.28	$ 346.87
Scenario #4	$ 24.62	$ 68.71	$ 116.34	$ 165.53	$ 263.90	$ 362.27
Scenario #17	$ 24.62	$ 67.80	$ 113.35	$ 160.45	$ 254.67	$ 348.89
Total Winter Bill Impact						
Scenario #4	$ -	$ 8.42	$ 27.55	$ 46.69	$ 84.95	$ 123.22
Scenario #17	$ -	$ 1.10	$ 3.61	$ 6.11	$ 11.12	$ 16.13
# Monthly Bills	17.2%	47.4%	20.7%	8.3%	5.0%	1.4%
Total Annual Bill Impact						
Scenario #4	$ -	$ 10.14	$ 38.84	$ 67.54	$ 124.89	$ 182.34
Scenario #17	$ -	$ 1.33	$ 5.09	$ 8.84	$ 16.35	$ 23.88

Note:
Current rates based on proposed D.05-03-022 rates adjusted for authorized 2005 ERRA and DWR revenue requirement changes.

Scenario #4 AMI net revenue requirement rate equals $0.00275 per kWh if applied to all Domestic sales, adjusted to $0.00957 per kWh to reflect upper tier sales only.

Scenario #17 AMI net revenue requirement rate equals $0.00036 per kWh if applied to all Domestic sales, adjusted to $0.00125 per kWh to reflect upper tier sales only.

Table K-5
2005 Revenue Requirement–Settlement (Adjusted for 2005 ERRA and DWR)
Estimates of Sales and Proposed Rate Revenue

		Scenario 4											
Line No.	Rate Schedule By Customer Group	Bundled MWh (M)	Bundled Delivery ($M)	Net AMI Rev Req ($M)	Bundled Generation ($M)	Bundled Total ($M)	Bundled Impact	DA MWh (M)	DA Delivery ($M)	Net AMI Rev Req ($M)	DA Generation ($M)	DA Total ($M)	DA Impact
1	Domestic												
2	D	20,135,434.6	1,451,218.2	55,779.8	1,382,582.0	2,889,580.1	1.968%	169,869.8	11,934.6	470.6	3,806.7	16,211.8	2.989%
3	D-CARE	4,768,928.4	154,403.3	13,290.9	292,355.4	460,049.6	2.975%	25,889.3	774.4	72.2	0.0	846.5	9.317%
4	D-APS	1,003,886.0	54,375.9	2,532.9	75,140.0	132,048.8	1.956%	17,007.9	946.9	42.9	381.1	1,371.0	3.231%
5	DE	98,588.6	3,519.9	74.0	6,910.5	10,504.4	0.709%	40.9	1.9	0.0	0.9	2.8	1.090%
6	DM	128,705.6	9,186.8	351.3	8,752.4	18,290.4	1.958%	4,411.8	307.8	12.0	98.9	418.7	2.961%
7	DMS-1	33,007.4	2,389.9	92.0	2,176.0	4,658.0	2.015%	305.1	21.3	0.9	6.8	29.0	3.025%
8	DMS-2	450,209.4	26,582.8	1,180.0	31,749.9	59,512.7	2.023%	10,875.4	640.7	28.5	243.7	913.0	3.223%
9		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
10	Group Total	26,618,760.1	1,701,676.9	73,300.9	1,799,666.2	3,574,644.0	2.094%	228,400.1	14,627.6	627.1	4,538.2	19,792.9	3.272%
11													
12	Lighting-SM Med Power												
13	GS-1	4,711,671.5	304,861.6	10,666.7	407,516.8	723,045.1	1.497%	68,342.3	4,386.7	154.7	1,531.6	6,073.0	2.614%
14	GS-2	20,815,376.6	1,122,008.3	42,480.7	1,742,809.3	2,907,298.3	1.483%	3,195,515.9	126,757.3	6,521.5	71,611.5	204,890.3	3.288%
15	GS-2-S	0.0	776.6	40.8	253.6	1,071.0	3.957%	0.0	1.0	0.0	0.0	1.0	0.000%
16	TC-1	83,701.5	3,791.2	152.1	5,434.6	9,377.8	1.648%	1,428.5	71.2	2.6	32.0	105.8	2.515%
17	TOU-GS-2	698,972.9	25,207.9	868.7	43,255.6	69,332.1	1.269%	90,170.7	2,823.7	112.1	2,020.7	4,956.5	2.313%
18		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
19	Group Total	26,309,722.6	1,456,645.6	54,208.9	2,199,269.9	3,710,124.4	1.483%	3,355,457.4	134,039.9	6,790.9	75,195.8	216,026.6	3.246%
20													
21	Large Power												
22	TOU-8-SEC	7,350,487.5	298,025.8	11,323.0	526,712.6	836,061.4	1.373%	2,033,165.9	77,681.2	3,132.0	45,563.2	126,376.4	2.541%
23	TOU-8-PRI	4,793,763.8	163,454.8	6,028.6	324,062.4	493,545.8	1.237%	1,675,413.6	52,660.0	2,107.0	37,546.0	92,313.1	2.336%
24	TOU-8-SUB	3,011,507.2	30,870.0	901.5	175,193.7	206,965.3	0.438%	4,155,215.8	58,491.6	1,243.9	93,118.4	152,853.9	0.820%
25	TOU-8-S-SEC	0.0	784.5	41.2	256.2	1,081.8	3.957%	0.0	0.0	0.0	0.0	0.0	0.000%
26	TOU-8-S-PRI	0.0	4,996.9	266.1	1,699.0	6,962.0	3.974%	0.0	0.2	0.0	0.0	0.2	0.000%
27	TOU-8-S-SUB	0.0	4,402.7	164.7	1,439.4	6,006.8	2.819%	0.0	0.1	0.0	0.0	0.1	0.000%
28		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
29	Group Total	15,155,758.4	502,534.7	18,725.2	1,029,363.2	1,550,623.1	1.222%	7,863,795.3	188,833.1	6,482.9	176,227.7	371,543.7	1.776%
30													
31	Agricultural & Pumping												
32	PA-1	414,290.5	24,491.5	1,044.1	37,680.9	63,216.5	1.679%	3,687.6	151.5	9.3	82.6	243.4	3.970%
33	PA-2	351,018.8	13,826.8	544.1	23,989.4	38,360.3	1.439%	8,830.7	283.6	13.7	197.9	495.1	2.843%
34	TOU-AG	1,192,100.3	45,425.4	1,681.5	45,943.7	93,050.6	1.840%	69,156.9	2,504.2	97.6	1,549.8	4,151.5	2.406%
35	TOU-PA-5	934,617.8	29,913.6	1,055.5	40,140.4	71,109.5	1.507%	6,914.7	227.8	7.8	155.0	390.6	2.040%
36		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
37	Group Total	2,892,027.4	113,657.3	4,325.2	147,754.4	265,736.9	1.655%	88,589.8	3,167.0	128.3	1,985.3	5,280.6	2.491%
38													
39	Street & Area Lighting												
40	LS-1	434,868.8	51,478.8	159.3	18,802.8	70,440.9	0.227%	4,448.7	146.7	1.6	99.7	248.0	0.661%
41	LS-2	97,687.3	4,175.6	35.8	4,223.8	8,435.2	0.426%	1,648.9	155.7	0.6	37.0	193.2	0.314%
42	LS-3	78,977.1	1,890.8	55.5	3,414.8	5,361.1	1.046%	9,106.2	208.9	6.4	204.1	419.4	1.550%
43	DWL	2,395.5	407.5	0.9	103.6	511.9	0.172%	15.7	2.9	0.0	0.4	3.3	0.175%
44	OL-1	13,383.7	1,558.2	4.9	578.7	2,141.8	0.229%	77.9	7.3	0.0	1.7	9.1	0.315%
45		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
46	Group Total	627,312.5	59,510.8	256.4	27,123.7	86,890.9	0.296%	15,297.4	521.5	8.7	342.8	873.0	1.003%
47													
48													
49	Total 5 Cust Gps.	71,603,580.9	3,834,025.3	150,816.6	5,203,177.3	9,188,019.2	1.669%	11,551,540.0	341,189.2	14,037.9	258,289.7	613,516.8	2.342%
50		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
51	CPUC Juris. Other												
52													
53	Spec. Con. Sub.	808,414.0	6,160.1	41.3	54,163.7	60,365.2	0.069%	0.0	0.0	0.0	0.0	0.0	0.000%
54		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
55	Group Total	808,414.0	6,160.1	41.3	54,163.7	60,365.2	0.069%	0.0	0.0	0.0	0.0	0.0	0.000%
56													
57		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
58	Grand Total	72,411,994.9	3,840,185.4	150,858.0	5,257,341.1	9,248,384.4	1.658%	11,551,540.0	341,189.2	14,037.9	258,289.7	613,516.8	2.342%

Table K-6
2005 Revenue Requirement-Settlement (Adjusted for 2005 ERRA and DWR)
Estimates of Sales and Proposed Rate Revenue

		Scenario 4											
Line No.	Rate Schedule By Customer Group	Bundled MWh (M)	Bundled Delivery ($M)	Net AMI Rev Req ($M)	Bundled Generation ($M)	Bundled Total ($M)	Bundled Impact	DA MWh (M)	DA Delivery ($M)	Net AMI Rev Req ($M)	DA Generation ($M)	DA Total ($M)	DA Impact
1	Domestic												
2	D	20,135,434.6	0.07207	0.00277	0.06866	0.14351	1.968%	169,869.8	0.07026	0.00277	0.02241	0.09544	2.989%
3	D-CARE	4,768,928.4	0.03238	0.00279	0.06130	0.09647	2.975%	25,889.3	0.02991	0.00279	0.00000	0.03270	9.317%
4	D-APS	1,003,886.0	0.05417	0.00252	0.07485	0.13154	1.956%	17,007.9	0.05568	0.00252	0.02241	0.08061	3.231%
5	DE	98,588.6	0.03570	0.00075	0.07009	0.10655	0.709%	40.9	0.04642	0.00075	0.02241	0.06958	1.090%
6	DM	128,705.6	0.07138	0.00273	0.06800	0.14211	1.958%	4,411.8	0.06977	0.00273	0.02241	0.09491	2.961%
7	DMS-1	33,007.4	0.07241	0.00279	0.06592	0.14112	2.015%	305.1	0.06975	0.00279	0.02241	0.09495	3.025%
8	DMS-2	450,209.4	0.05905	0.00262	0.07052	0.13219	2.023%	10,875.4	0.05892	0.00262	0.02241	0.08395	3.223%
9		----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
10	Group Total	26,618,760.1	0.06393	0.00275	0.06761	0.13429	2.094%	228,400.1	0.06404	0.00275	0.01987	0.08666	3.272%
11													
12	Lighting-SM Med Power												
13	GS-1	4,711,671.5	0.06470	0.00226	0.08649	0.15346	1.497%	68,342.3	0.06419	0.00226	0.02241	0.08886	2.614%
14	GS-2	20,815,376.6	0.05390	0.00204	0.08373	0.13967	1.483%	3,195,515.9	0.03967	0.00204	0.02241	0.06412	3.288%
15	GS-2-S	0.0						0.0					
16	TC-1	83,701.5	0.04529	0.00182	0.06493	0.11204	1.648%	1,428.5	0.04984	0.00182	0.02241	0.07407	2.515%
17	TOU-GS-2	698,972.9	0.03606	0.00124	0.06188	0.09919	1.269%	90,170.7	0.03132	0.00124	0.02241	0.05497	2.313%
18		----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
19	Group Total	26,309,722.6	0.05537	0.00206	0.08359	0.14102	1.483%	3,355,457.4	0.03995	0.00202	0.02241	0.06438	3.246%
20													
21	Large Power												
22	TOU-8-SEC	7,350,487.5	0.04055	0.00154	0.07166	0.11374	1.373%	2,033,165.9	0.03821	0.00154	0.02241	0.06216	2.541%
23	TOU-8-PRI	4,793,763.8	0.03410	0.00126	0.06760	0.10296	1.237%	1,675,413.6	0.03143	0.00126	0.02241	0.05510	2.336%
24	TOU-8-SUB	3,011,507.2	0.01025	0.00030	0.05817	0.06872	0.438%	4,155,215.8	0.01408	0.00030	0.02241	0.03679	0.820%
25	TOU-8-S-SEC	0.0						0.0					
26	TOU-8-S-PRI	0.0						0.0					
27	TOU-8-S-SUB	0.0						0.0					
28		----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
29	Group Total	15,155,758.4	0.03316	0.00124	0.06792	0.10231	1.222%	7,863,795.3	0.02401	0.00082	0.02241	0.04725	1.776%
30													
31	Agricultural & Pumping												
32	PA-1	414,290.5	0.05912	0.00252	0.09095	0.15259	1.679%	3,687.6	0.04107	0.00252	0.02241	0.06600	3.970%
33	PA-2	351,018.8	0.03939	0.00155	0.06834	0.10928	1.439%	8,830.7	0.03211	0.00155	0.02241	0.05607	2.843%
34	TOU-AG	1,192,100.3	0.03811	0.00141	0.03854	0.07806	1.840%	69,156.9	0.03621	0.00141	0.02241	0.06003	2.406%
35	TOU-PA-5	934,617.8	0.03201	0.00113	0.04295	0.07608	1.507%	6,914.7	0.03295	0.00113	0.02241	0.05649	2.040%
36		----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
37	Group Total	2,892,027.4	0.03930	0.00150	0.05109	0.09189	1.655%	88,589.8	0.03575	0.00145	0.02241	0.05961	2.491%
38													
39	Street & Area Lighting												
40	LS-1	434,868.8	0.11838	0.00037	0.04324	0.16198	0.227%	4,448.7	0.03297	0.00037	0.02241	0.05575	0.661%
41	LS-2	97,687.3	0.04274	0.00037	0.04324	0.08635	0.426%	1,648.9	0.09441	0.00037	0.02241	0.11718	0.314%
42	LS-3	78,977.1	0.02394	0.00070	0.04324	0.06788	1.046%	9,106.2	0.02295	0.00070	0.02241	0.04606	1.550%
43	DWL	2,395.5	0.17010	0.00037	0.04324	0.21370	0.172%	15.7	0.18660	0.00037	0.02241	0.20937	0.175%
44	OL-1	13,383.7	0.11642	0.00037	0.04324	0.16003	0.229%	77.9	0.09380	0.00037	0.02241	0.11658	0.315%
45		----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
46	Group Total	627,312.5	0.09487	0.00041	0.04324	0.13851	0.296%	15,297.4	0.03409	0.00057	0.02241	0.05707	1.003%
47													
48													
49	Total 5 Cust Gps.	71,603,580.9	0.05355	0.00211	0.07267	0.12832	1.669%	11,551,540.0	0.02954	0.00122	0.02236	0.05311	2.342%
50		----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
51	CPUC Juris. Other												
52													
53	Spec. Con. Sub.	808,414.0	0.00762	0.00005	0.06700	0.07467	0.069%	0.0					
54		----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
55	Group Total	808,414.0	0.00762	0.00005	0.06700	0.07467	0.069%	0.0					
56													
57		----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
58	Grand Total	72,411,994.9	0.05303	0.00208	0.07260	0.12772	1.658%	11,551,540.0	0.02954	0.00122	0.02236	0.05311	2.342%

Table K-7
2005 Revenue Requirement-Settlement (Adjusted for 2005 ERRA and DWR)
Estimates of Sales and Proposed Rate Revenue

		Scenario 17											
Line No.	Rate Schedule By Customer Group	Bundled MWh (M)	Bundled Delivery ($M)	Net AMI Rev Req ($M)	Bundled Generation ($M)	Bundled Total ($M)	Bundled Impact	DA MWh (M)	DA Delivery ($M)	Net AMI Rev Req ($M)	DA Generation ($M)	DA Total ($M)	DA Impact
1	Domestic												
2	D	20,135,434.6	1,451,218.2	7,303.9	1,382,582.0	2,841,104.2	0.258%	169,869.8	11,934.6	61.6	3,806.7	15,802.9	0.391%
3	D-CARE	4,768,928.4	154,403.3	1,740.3	292,355.4	448,499.0	0.390%	25,889.3	774.4	9.4	0.0	783.8	1.220%
4	D-APS	1,003,886.0	54,375.9	331.7	75,140.0	129,847.6	0.256%	17,007.9	946.9	5.6	381.1	1,333.7	0.423%
5	DE	98,588.6	3,519.9	9.7	6,910.5	10,440.1	0.093%	40.9	1.9	0.0	0.9	2.8	0.143%
6	DM	128,705.6	9,186.8	46.0	8,752.4	17,985.2	0.256%	4,411.8	307.8	1.6	98.9	408.3	0.388%
7	DMS-1	33,007.4	2,389.9	12.0	2,176.0	4,578.0	0.264%	305.1	21.3	0.1	6.8	28.2	0.396%
8	DMS-2	450,209.4	26,582.8	154.5	31,749.9	58,487.2	0.265%	10,875.4	640.7	3.7	243.7	888.2	0.422%
9													
10	Group Total	26,618,760.1	1,701,676.9	9,598.2	1,799,666.2	3,510,941.2	0.274%	228,400.1	14,627.6	82.1	4,538.2	19,247.9	0.428%
11													
12	Lighting-SM Med Power												
13	GS-1	4,711,671.5	304,861.6	1,396.7	407,516.8	713,775.2	0.196%	68,342.3	4,386.7	20.3	1,531.6	5,938.5	0.342%
14	GS-2	20,815,376.6	1,122,008.3	5,562.5	1,742,809.3	2,870,380.1	0.194%	3,195,515.9	126,757.3	853.9	71,611.5	199,222.7	0.430%
15	GS-2-S	0.0	776.6	5.3	253.6	1,035.6	0.518%	0.0	1.0	0.0	0.0	1.0	0.000%
16	TC-1	83,701.5	3,791.2	19.9	5,434.6	9,245.7	0.216%	1,428.5	71.2	0.3	32.0	103.6	0.329%
17	TOU-GS-2	698,972.9	25,207.9	113.7	43,255.6	68,577.2	0.166%	90,170.7	2,823.7	14.7	2,020.7	4,859.1	0.303%
18													
19	Group Total	26,309,722.6	1,456,645.6	7,098.2	2,199,269.9	3,663,013.7	0.194%	3,355,457.4	134,039.9	889.2	75,195.8	210,124.9	0.425%
20													
21	Large Power												
22	TOU-8-SEC	7,350,487.5	298,025.8	1,482.7	526,712.6	826,221.1	0.180%	2,033,165.9	77,681.2	410.1	45,563.2	123,654.5	0.333%
23	TOU-8-PRI	4,793,763.8	163,454.8	789.4	324,062.4	488,306.5	0.162%	1,675,413.6	52,660.0	275.9	37,546.0	90,481.9	0.306%
24	TOU-8-SUB	3,011,507.2	30,870.0	118.0	175,193.7	206,181.8	0.057%	4,155,215.8	58,491.6	162.9	93,118.4	151,772.8	0.107%
25	TOU-8-S-SEC	0.0	784.5	5.4	256.2	1,046.1	0.518%	0.0	0.0	0.0	0.0	0.0	0.000%
26	TOU-8-S-PRI	0.0	4,996.9	34.8	1,699.0	6,730.7	0.520%	0.0	0.2	0.0	0.0	0.2	0.000%
27	TOU-8-S-SUB	0.0	4,402.7	21.6	1,439.4	5,863.6	0.369%	0.0	0.1	0.0	0.0	0.1	0.000%
28													
29	Group Total	15,155,758.4	502,534.7	2,451.9	1,029,363.2	1,534,349.8	0.160%	7,863,795.3	188,833.1	848.9	176,227.7	365,909.6	0.233%
30													
31	Agricultural & Pumping												
32	PA-1	414,290.5	24,491.5	136.7	37,680.9	62,309.1	0.220%	3,687.6	151.5	1.2	82.6	235.3	0.520%
33	PA-2	351,018.8	13,826.8	71.2	23,989.4	37,887.5	0.188%	8,830.7	283.6	1.8	197.9	483.2	0.372%
34	TOU-AG	1,192,100.3	45,425.4	220.2	45,943.7	91,589.2	0.241%	69,156.9	2,504.2	12.8	1,549.8	4,066.8	0.315%
35	TOU-PA-5	934,617.8	29,913.6	138.2	40,140.4	70,192.2	0.197%	6,914.7	227.8	1.0	155.0	383.8	0.267%
36													
37	Group Total	2,892,027.4	113,657.3	566.4	147,754.4	261,978.0	0.217%	88,589.8	3,167.0	16.8	1,985.3	5,169.1	0.326%
38													
39	Street & Area Lighting												
40	LS-1	434,868.8	51,478.8	20.9	18,802.8	70,302.4	0.030%	4,448.7	146.7	0.2	99.7	246.6	0.087%
41	LS-2	97,687.3	4,175.6	4.7	4,223.8	8,404.1	0.056%	1,648.9	155.7	0.1	37.0	192.7	0.041%
42	LS-3	78,977.1	1,890.8	7.3	3,414.8	5,312.9	0.137%	9,106.2	208.9	0.8	204.1	413.9	0.203%
43	DWL	2,395.5	407.5	0.1	103.6	511.2	0.022%	15.7	2.9	0.0	0.4	3.3	0.023%
44	OL-1	13,383.7	1,558.2	0.6	578.7	2,137.5	0.030%	77.9	7.3	0.0	1.7	9.1	0.041%
45													
46	Group Total	627,312.5	59,510.8	33.6	27,123.7	86,668.1	0.039%	15,297.4	521.5	1.1	342.8	865.5	0.131%
47													
48													
49	Total 5 Cust Gps.	71,603,580.9	3,834,025.3	19,748.2	5,203,177.3	9,056,950.8	0.219%	11,551,540.0	341,189.2	1,838.1	258,289.7	601,317.1	0.307%
50													
51	CPUC Juris. Other												
52													
53	Spec. Con. Sub.	808,414.0	6,160.1	5.4	54,163.7	60,329.3	0.009%	0.0	0.0	0.0	0.0	0.0	0.000%
54													
55	Group Total	808,414.0	6,160.1	5.4	54,163.7	60,329.3	0.009%	0.0	0.0	0.0	0.0	0.0	0.000%
56													
57													
58	Grand Total	72,411,994.9	3,840,185.4	19,753.6	5,257,341.1	9,117,280.1	0.217%	11,551,540.0	341,189.2	1,838.1	258,289.7	601,317.1	0.307%
				21,591.8									

Scaling distribution rates for the entire Domestic rate group would result in violation of rate level restrictions imposed by AB1X, because increases in the distribution component would result in an overall increase in total rates for usage up to 130 percent of baseline allowances. In order to avoid this result, SCE proposes to maintain current monthly customer charges and to reduce the SCE Generation component of Tier 1 and 2 energy charges to offset increases in the distribution component. Based on the most recently authorized sales forecast for the Domestic rate group, SCE then determines the resulting generation revenue under-collection. The SCE Generation component of Tier 3 and 4 energy charges are then adjusted upward (by an equal percentage) to offset the revenue under-collection. This methodology for domestic tiered rate design in the presence of AB1X restrictions was first proposed by SCE in Advice 1808-E, in implementing Commission authorized revenue requirements in Phase 1 of the 2003 GRC. The Commission subsequently approved SCE's methodology on an interim basis and ordered SCE to file an application to formally propose this rate design methodology. SCE filed its application for approval of its generic proposal for allocating AB1X generation revenue shortfalls on March 28, 2005.

Scaling distribution rate components on a SAPC basis results in rate group average impacts which vary between classes, based on the ratio of class distribution revenue to the total revenue requirement. In addition, the rate adjustments necessitated by AB1X restrictions result in a disproportionate impact of revenue increases on domestic customers served in the higher usage tiers. Nearly 40 percent of domestic service customers are insulated from bill impacts, because Tier 1 and Tier 2 energy charges are not increased. Table K-8 includes illustrative percentage monthly bill impacts for domestic service customers by usage level. As discussed above, the highest absolute and percentage impacts are expected to occur for customers with the largest portion of their total consumption in the upper tiers while customers whose usage is concentrated in the lower tiers enjoy the protection offered by AB1X.

Table K-8
2005 Revenue Requirement-Settlement (Adjusted for 2005 ERRA and DWR) Estimates of Sales and Proposed Rate Revenue

		Scenario 17											
Line No.	Rate Schedule By Customer Group	Bundled MWh (M)	Bundled Delivery ($M)	Net AMI Rev Req ($M)	Bundled Generation ($M)	Bundled Total ($M)	Bundled Impact	DA MWh (M)	DA Delivery ($M)	Net AMI Rev Req ($M)	DA Generation ($M)	DA Total ($M)	DA Impact
1	Domestic												
2	D	20,135,434.6	0.07207	0.00036	0.06866	0.14110	0.258%	169,869.8	0.07026	0.00036	0.02241	0.09303	0.391%
3	D-CARE	4,768,928.4	0.03238	0.00036	0.06130	0.09405	0.390%	25,889.3	0.02991	0.00036	0.00000	0.03028	1.220%
4	D-APS	1,003,886.0	0.05417	0.00033	0.07485	0.12934	0.256%	17,007.9	0.05568	0.00033	0.02241	0.07842	0.423%
5	DE	98,588.6	0.03570	0.00010	0.07009	0.10590	0.093%	40.9	0.04642	0.00010	0.02241	0.06893	0.143%
6	DM	128,705.6	0.07138	0.00036	0.06800	0.13974	0.256%	4,411.8	0.06977	0.00036	0.02241	0.09254	0.388%
7	DMS-1	33,007.4	0.07241	0.00037	0.06592	0.13870	0.264%	305.1	0.06975	0.00037	0.02241	0.09252	0.396%
8	DMS-2	450,209.4	0.05905	0.00034	0.07052	0.12991	0.265%	10,875.4	0.05892	0.00034	0.02241	0.08167	0.422%
9		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
10	Group Total	26,618,760.1	0.06393	0.00036	0.06761	0.13190	0.274%	228,400.1	0.06404	0.00036	0.01987	0.08427	0.428%
11													
12	Lighting-SM Med Power												
13	GS-1	4,711,671.5	0.06470	0.00030	0.08649	0.15149	0.196%	68,342.3	0.06419	0.00030	0.02241	0.08689	0.342%
14	GS-2	20,815,376.6	0.05390	0.00027	0.08373	0.13790	0.194%	3,195,515.9	0.03967	0.00027	0.02241	0.06234	0.430%
15	GS-2-S	0.0						0.0					
16	TC-1	83,701.5	0.04529	0.00024	0.06493	0.11046	0.216%	1,428.5	0.04984	0.00024	0.02241	0.07249	0.329%
17	TOU-GS-2	698,972.9	0.03606	0.00016	0.06188	0.09811	0.166%	90,170.7	0.03132	0.00016	0.02241	0.05389	0.303%
18		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
19	Group Total	26,309,722.6	0.05537	0.00027	0.08359	0.13923	0.194%	3,355,457.4	0.03995	0.00027	0.02241	0.06262	0.425%
20													
21	Large Power												
22	TOU-8-SEC	7,350,487.5	0.04055	0.00020	0.07166	0.11240	0.180%	2,033,165.9	0.03821	0.00020	0.02241	0.06082	0.333%
23	TOU-8-PRI	4,793,763.8	0.03410	0.00016	0.06760	0.10186	0.162%	1,675,413.6	0.03143	0.00016	0.02241	0.05401	0.306%
24	TOU-8-SUB	3,011,507.2	0.01025	0.00004	0.05817	0.06846	0.057%	4,155,215.8	0.01408	0.00004	0.02241	0.03653	0.107%
25	TOU-8-S-SEC	0.0						0.0					
26	TOU-8-S-PRI	0.0						0.0					
27	TOU-8-S-SUB	0.0						0.0					
28		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
29	Group Total	15,155,758.4	0.03316	0.00016	0.06792	0.10124	0.160%	7,863,795.3	0.02401	0.00011	0.02241	0.04653	0.233%
30													
31	Agricultural & Pumping												
32	PA-1	414,290.5	0.05912	0.00033	0.09095	0.15040	0.220%	3,687.6	0.04107	0.00033	0.02241	0.06381	0.520%
33	PA-2	351,018.8	0.03939	0.00020	0.06834	0.10794	0.188%	8,830.7	0.03211	0.00020	0.02241	0.05472	0.372%
34	TOU-AG	1,192,100.3	0.03811	0.00018	0.03854	0.07683	0.241%	69,156.9	0.03621	0.00018	0.02241	0.05880	0.315%
35	TOU-PA-5	934,617.8	0.03201	0.00015	0.04295	0.07510	0.197%	6,914.7	0.03295	0.00015	0.02241	0.05550	0.267%
36		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
37	Group Total	2,892,027.4	0.03930	0.00020	0.05109	0.09059	0.217%	88,589.8	0.03575	0.00019	0.02241	0.05835	0.326%
38													
39	Street & Area Lighting												
40	LS-1	434,868.8	0.11838	0.00005	0.04324	0.16166	0.030%	4,448.7	0.03297	0.00005	0.02241	0.05543	0.087%
41	LS-2	97,687.3	0.04274	0.00005	0.04324	0.08603	0.056%	1,648.9	0.09441	0.00005	0.02241	0.11687	0.041%
42	LS-3	78,977.1	0.02394	0.00009	0.04324	0.06727	0.137%	9,106.2	0.02295	0.00009	0.02241	0.04545	0.203%
43	DWL	2,395.5	0.17010	0.00005	0.04324	0.21339	0.022%	15.7	0.18660	0.00005	0.02241	0.20906	0.023%
44	OL-1	13,383.7	0.11642	0.00005	0.04324	0.15971	0.030%	77.9	0.09380	0.00005	0.02241	0.11626	0.041%
45		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
46	Group Total	627,312.5	0.09487	0.00005	0.04324	0.13816	0.039%	15,297.4	0.03409	0.00007	0.02241	0.05658	0.131%
47													
48													
49	Total 5 Cust Gps.	71,603,580.9	0.05355	0.00028	0.07267	0.12649	0.219%	11,551,540.0	0.02954	0.00016	0.02236	0.05206	0.307%
50		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
51	CPUC Juris. Other												
52													
53	Spec. Con. Sub.	808,414.0	0.00762	0.00001	0.06700	0.07463	0.009%	0.0					
54		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
55	Group Total	808,414.0	0.00762	0.00001	0.06700	0.07463	0.009%	0.0					
56													
57		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
58	Grand Total	72,411,994.9	0.05303	0.00027	0.07260	0.12591	0.217%	11,551,540.0	0.02954	0.00016	0.02236	0.05206	0.307%

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Southern California Edison Company's (U 338-E) Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism	A.05-03-____ (Filed March 30, 2005)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) APPLICATION FOR APPROVAL OF ADVANCED METERING INFRASTRUCTURE DEPLOYMENT STRATEGY AND COST RECOVERY MECHANISM

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Dated: March 30, 2005

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Southern California Edison Company's (U 338-E) Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism	A.05-03-____ (Filed March 31, 2005)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) APPLICATION FOR APPROVAL OF ADVANCED METERING INFRASTRUCTURE DEPLOYMENT STRATEGY AND COST RECOVERY MECHANISMS

I.
INTRODUCTION

In accordance with the California Public Utilities Commission's ("Commission") directives set forth in the Assigned Commissioner and Administrative Law Judge's Ruling Calling for a Technical Conference to Begin Development of a Reference Design and Delaying Filing Date of Utility Advanced Metering Infrastructure Applications issued on November 24, 2004 ("Ruling") and as modified by the ruling of Administrative Law Judge Michelle Cooke on March 2, 2005, granting SCE's request for an extension of this application until April 1, 2005, Southern California Edison Company ("SCE" or "Company") hereby files this Application seeking approval of its deployment strategy for advanced metering infrastructure ("AMI"). The testimony in support of this Application discusses SCE's vision and deployment strategy for AMI, as well as an analysis of the two best business case scenarios for a full and partial deployment of AMI, including the methodologies and assumptions used in performing that analysis. The testimony also includes SCE's proposed cost recovery mechanism for the $31 million costs estimated for the proposed deployment strategy.

II.

ORGANIZATION OF SCE'S TESTIMONY

The testimony submitted in support of this Application is comprised of three volumes of testimony and one volume of appendices:

Exhibit SCE-1: Business Vision, Management Philosophy, and Summary of Business Case Analysis

Executive Summary

Chapter I: Introduction

Chapter II: SCE's Business Vision for Advanced Metering Infrastructure

Chapter III: SCE's Management Philosophy for Investment in Advanced Metering Infrastructure

Chapter IV: Summary of Business Case Analysis

Chapter V: Conclusion

Exhibit SCE-2: Technology and Market Assessment, Deployment Strategy, and Cost Recovery Proposal

Chapter I: Introduction

Chapter II: Current Technology and Market Assessment

Chapter III: Proposed Deployment Strategy

Chapter IV: Cost Recovery Proposal

Exhibit SCE-3: Advanced Metering Infrastructure Business Case Analysis

Chapter I: Introduction

Chapter II: Summary of Results

Chapter III: Overview of Best Full and Partial Deployment Scenarios

Chapter IV: Best Full Deployment Business Case Analysis

Chapter V: Best Partial Deployment Business Case Analysis

Chapter VI: Revenue Requirement and Customer Impact Analysis

Exhibit SCE-4: Appendices Supporting Business Case Analysis

III.

SUMMARY OF SCE'S ADVANCED INTEGRATED METER DEVELOPMENT PROPOSAL

In compliance with the Ruling, SCE sets forth its proposal for its preferred deployment strategy for AMI in its service territory. This strategy was carefully developed based on a thorough and rigorous business case analysis of current AMI technology using the Commission's required and SCE's alternative assumptions. SCE's findings indicate that an integrated AMI solution that leverages additional commercially-available technologies has the potential to provide an effective platform for enhancing routine customer services, providing more sophisticated alternatives for load management and demand response, and increasing operational efficiencies and benefits. However, these enabling technologies have yet to be cost-effectively packaged or integrated into a streamlined meter for application in the United States. Therefore, SCE has concluded that given its operational starting point, an investment in currently-available AMI technology is not cost effective for SCE's customers. Instead, SCE proposes to achieve significant increased operational and demand response benefits through a concerted and aggressive effort to develop an "advanced integrated meter" (AIM) that integrates additional technologies into the next generation of meters.

SCE's business vision for AMI seeks to undertake a deliberate, yet fast-paced effort to design and develop a new AIM platform that will better meet SCE's and its customer needs by integrating additional proven technologies. The goal of the AIM project will be to add significantly more functionality at the same or lower cost as today's solutions, in order to significantly increase benefits over the current AMI business case.

The AIM development will take a "clean sheet" approach to design a meter that provides additional functional capabilities not available in currently-available metering solutions, including the possible integration of load control, demand limiting, two-way communications, customer information displays, data storage, and/or other proven stand-alone technologies. SCE seeks to significantly increase overall durability and versatility of AMI by using open, extensible and multifunctional meter and communications platforms. The AIM project is expected to leverage commercially-available components through an open design for both the meter device and communications, to provide a flexible and sustainable technology platform during its long lifecycle. This is essential given recent and anticipated future technology developments in home connectivity, distribution grid intelligence, distributed generation, and broadband over power lines, all of which may interface with the AIM technology.

SCE has developed a detailed strategy and aggressive timeline for the AIM development project that allows for integrated meter design, prototype development, beta production, and pilot test before a new business case would be prepared for Commission approval of full deployment. If there are no major obstacles and the AIM technology delivers its promised improvements to the business case analysis, SCE envisions completing full deployment of the new AIM system no later than one to two years after the time that full deployment of today's AMI technology could be completed. SCE's customers would nevertheless be advantaged, despite this slight delay, given the superior attributes of the proposed AIM technology, including more durability, versatility and the ability to deliver significant improvements in system reliability, customer billing and service options, outage management and operational efficiencies.

This Application seeks authorization of the first two phases of this AIM development effort: Phase I (design and development of the meter) and Phase II (beta development and pilot deployment). SCE estimates that the cost of Phase I will be approximately $12 million and Phase II will be approximately $19 million, for a total cost of $31 million for the activities that are the subject of this Application. These phases will be followed by one subsequent phase, namely Phase III, which is actual deployment of the new meters following Commission approval of a new business case application to be submitted at the end of Phase II.

IV.

SUMMARY OF SCE'S RATEMAKING PROPOSAL

SCE seeks Commission approval of its cost recovery proposal. SCE seeks to establish the Advanced Integrated Meter Balancing Account ("AIMBA") to provide for the recovery of Phase I and Phase II recorded costs effective upon a Commission decision on this application. Similar to ratemaking principles applicable to other Commission-approved balancing accounts, the proposed operation of the AIMBA will ensure that no more and no less than SCE's recorded AIM-related revenue requirements for Phase I and Phase II activities are ultimately collected from customers. In the AIMBA each month, SCE will record the difference between the actual capital-related revenue requirement and the actual O&M costs incurred for AIM Phase I and Phase II activities and the Commission-authorized AIM-related revenue requirement collected in rates. Any under- or over-collections in the AIMBA will be returned to, or collected from, customers in the following year.

SCE proposes that the AIM-related revenue requirements will be collected in rates as one component of SCE's total distribution revenue requirement through SCE distribution rate levels. Regardless of the effective date of the Commission's decision on this application, SCE proposes to begin the actual rate recovery of the AIM-related revenue requirement on January 1, 2006, when all other authorized rate changes are consolidated. SCE will present its January 1st AIM-related revenue requirements to the Commission for approval at least 60 days in advance by Advice Letter. SCE proposes to consolidate the changes to its distribution rate levels to reflect the updated annual AMI-related revenue requirements in conjunction with other rate level changes in the annual Energy Resources Recovery Account ("ERRA") applications.

Pursuant to Commission-adopted review procedures for other SCE balancing accounts, SCE proposes that the recorded operation of the AIMBA be reviewed by the Commission in SCE's annual ERRA reasonableness applications to ensure that all entries to the account are stated correctly and are consistent with Commission decisions. Due to the uncertainties surrounding a successful outcome of our AIM Project as we proceed through the Phase I and Phase II tasks, or the possibility that a future Commission may change its view about deployment of AMI, Commission reasonableness review of the AIMBA should be limited to ensuring that all recorded costs are associated with Phase I and Phase II activities as defined and adopted by the Commission in this proceeding.

V.

SUMMARY OF REQUESTS

This Application seeks Commission approval of SCE's proposed AIM Project and cost recovery for expenditures incurred therein. SCE respectfully requests that the Commission:

(1) Authorize SCE to design a customized advanced meter integrating additional functionality;

(2) Authorize SCE to develop working prototypes of the new meter design;

(3) Authorize SCE to conduct a beta test of production of the new meter design;

(4) Authorize SCE to conduct a pilot deployment of the new meter design;

(5) Authorize SCE to establish the Advanced Integrated Meter Balancing Account to provide for the recovery of Phase I and Phase II recorded costs effective upon a Commission decision on this application;

(6) Authorize rate recovery, through distribution rate levels, of our forecast AIM-related revenue requirement for Phase I and Phase II activities beginning on January 1, 2006 and continuing through the completion of Phase II; and

(7) Limit reasonableness review of the Advanced Integrated Meter Balancing Account to ensuring all recorded costs are associated with Phase I and Phase II activities as defined and adopted by the Commission in this proceeding.

VI.

STATUTORY AND PROCEDURAL REQUIREMENTS

A. Statutory and Procedural Authority

This application is made pursuant to the Commission's Rules of Practice and Procedure, the California Public Utilities Code, the Assigned Commissioner and Administrative Law Judge's Ruling Calling for a Technical Conference to Begin Development of a Reference Design and Delaying Filing of Utility Advanced Metering Infrastructure Applications issued on November 24, 2004, and the ruling of Administrative Law Judge Michelle Cooke on March 2, 2005, granting SCE's request for an extension of this application until April 1, 2005.

SCE's authority for this request is Sections 399.2, 451, 454, 491, 701, 728, and 729 of the Public Utilities Code of the State of California. SCE's request complies with Rules 2 through 2.5, which specify the procedures for the filing of documents, specifically:[1]

1. Form and size of tendered documents (Rule 2);
2. Caption, title, and docket number (Rule 2.1);
3. Signatures (Rule 2.2);
4. Service (Rule 2.3);
5. Verification (Rule 2.4); and
6. Copies (Rule 2.5).

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[1] Because this is a new application, no service list has yet been established. SCE is serving this application in accordance with the service directives on the service list established for R.02-06-001.

In addition, this request complies with Rules 6, 15, 16, 23, 24, 42, and prior decisions, orders and resolutions of this Commission.

B. SB 960 Requirements – Rule 6(a)(1)

Rule 6(a)(1) requires that applications filed after January 1, 1998 "shall state the proposed category for the proceeding, the need for hearings, the issues to be considered, and a proposed schedule." These requirements are discussed below.

C. Proposed Categorization

SCE proposes to characterize this proceeding as "ratesetting" as defined in Rule 5(c).

D. Need For Hearings and Proposed Schedule For Resolution of Issues

Given the time necessary to develop the new AIM product before SCE could file a new business case for a full deployment of AMI, SCE proposes that these issues be addressed as expeditiously as possible so that it may begin its meter design and development activities. Our proposed schedule assumes that there will be evidentiary hearings and briefing, although SCE anticipates that many of the issues addressed in this application may be resolved through settlement or stipulation or through written comments, depending on whether intervening parties dispute factual issues.

If the Commission believes evidentiary hearings are necessary, then SCE proposes the following schedule, which is extremely aggressive but provides the minimal amount of time necessary to allow SCE to begin its design and development activities by January 2006. Any delay to the following schedule would affect SCE's ability to begin these important tasks and would further delay SCE's eventual filing of a new business case and full deployment of AMI.

SCE files Application	March 30, 2005
Daily Calendar Notice Appears	April 2005
Prehearing Conference	April 15, 2005
ORA and Intervenors File Opening Testimony	May 6, 2005
SCE Reply Testimony Due	May 20, 2005
Hearings	May 30-June 3, 2005
Concurrent Opening Briefs Due	June 20, 2005
Concurrent Reply Briefs Due	July 1, 2005
Commission Issues Proposed Decision Due	August 1, 2005
Comments to Proposed Decision Due	August 21, 2005
Replies to Comments to Proposed Decision	September 1, 2005
Commission issues Final Decision	September 8, 2005

E. Issues to be Considered

The issues to be considered in this proceeding are described above and set forth in much greater detail in the attached Prepared Testimony. Major issues include:

1. Whether to adopt SCE's deployment strategy, including SCE's efforts to undertake development of a customized "Advanced Integrated Meter" through a pilot deployment; and
2. Whether to adopt SCE's proposed ratemaking treatment for the recovery of the associated costs of SCE's proposed deployment strategy.

F. Legal Name and Correspondence – Rules 15(a) and 15(b)

Southern California Edison Company is an electric public utility organized and existing under the laws of the State of California. The location of SCE's principal place of business is 2244 Walnut Grove Avenue, Post Office Box 800, Rosemead, California 91770. SCE's attorneys in this matter are Jennifer

Hasbrouck and Laura Genao. Correspondence or communications regarding this application should be addressed to:

Jennifer R. Hasbrouck
Senior Attorney
Southern California Edison Company
P.O. Box 800
2244 Walnut Grove Avenue
Rosemead, California 91770
Telephone: (626) 302-1040
Facsimile: (626) 302-7740
e-mail: jennifer.hasbrouck@sce.com

To request a copy of this application, please contact:

Meraj Rizvi
Southern California Edison Company
P.O. Box 800
2244 Walnut Grove Avenue
Rosemead, California 91770
Telephone: (626) 302-1063
Facsimile: (626) 302-1048
E-mail: caseadmin@sce.com

G. Articles Of Incorporation – Rule 16

A copy of SCE's Restated Articles of Incorporation, as amended, and as presently in effect, certified by the California Secretary of State, was filed with the Commission on June 15, 1993, in connection with Application 93-06-022[2] and is incorporated herein by reference pursuant to Rule 16 of the Commission's Rules of Practice and Procedure.

A certificate of correction to the Restated Articles of Incorporation, amending Paragraph 5 of Exhibit I to the Articles, was filed with the Commission on

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[2] A.93-06-022, filed June 15, 1993, regarding approval of a Self-Generation Deferral Agreement between Mobil Oil Corporation, Torrance Refinery, and SCE.

September 19, 1997, in connection with Application 97-09-038,[3] and is also incorporated herein by reference pursuant to Rule 16.

SCE's Articles of Incorporation were again amended on January 12, 2005, and were certified by the California Secretary of State. A copy of the certified amended Articles of Incorporation was filed with the Commission on January 20, 2005, in connection with Application 05-01-018,[4] and is also incorporated herein by reference pursuant to Rule 16.

H. Balance Sheet and Income Statement – Rule 23(a)

Appendix A to this application contains copies of SCE's balance sheet as of December 31, 2004, and income statement for the period ended September 30, 2004, the most recent period available.

I. Present and Proposed Rates – Rule 23(b) and Rule 23(c)

The cost recovery mechanism proposal and the AIMBA's projected impact on rates are addressed in Exhibit SCE-2, incorporated herein by reference.

J. Description of SCE's Service Territory and Utility System – Rule 23(d)

Because this submittal is not a general rate application, this requirement is not applicable.

K. Summary of Earnings – Rule 23(e)

Rule 23(e) requires:

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[3] A.97-09-038, filed September 19, 1997, regarding expedited and *ex parte* approval of negotiated termination of certain Interim Standard Offer No. 4 Power Purchase Contracts.

[4] A.05-01-018, filed January 20, 2005, regarding default critical peak pricing rate design for large customers.

> A summary of earnings (rate of return summary) on a depreciated rate base for the test period or periods upon which applicant bases its justification for an increase.

A Summary of Earnings was provided in SCE's General Rate Case Application, A.02-05-004, filed with the Commission on May 3, 2002, and is incorporated herein by this reference.

L. Index of the Exhibits and Appendices to This Application – Rule 23(g)

SCE's submissions in support of this application include the following, which are incorporated herein by reference:

Appendices to Application

Appendix A	Balance Sheet and Income Statement
Appendix B	List of Cities and Counties

Exhibits to Application

SCE-1	Business Vision, Management Philosophy, and Summary of Business Case Analysis
SCE-2	Technology and Market Assessment, Deployment Strategy, and Cost Recovery Proposal
SCE-3	Advanced Metering Infrastructure Business Case Analysis
SCE-4	Appendices to Testimony

M. Depreciation – Rule 23(h)

Because this submittal is not a general rate application, this requirement is not applicable.

N. Capital Stock and Proxy Statement – Rule 23(i)

Because this submittal is not a general rate application, this requirement is not applicable.

O. Statement Pursuant to Rule 23(l)

Rule 23(l) requires the applicant to state whether its request is limited to passing through to customers "only increased costs to the corporation for the services or commodities furnished by it." This application seeks only to pass through to SCE's customers the costs incurred by SCE in Phase I and II of its proposed AIM Project.

P. Service of Notice – Rule 24

A list of the cities and counties affected by the rate changes resulting from this application is attached as Appendix B. The State of California is also an SCE customer whose rates would be affected by the proposed revisions.

As provided in Rule 24, notice of filing of this application will be: (1) mailed to the appropriate officials of the state and the counties and cities listed in Appendix B; (2) published in a newspaper of general circulation in each county in SCE's service territory within which the rate changes would be effective; and (3) mailed to all customers affected by the proposed changes.

Q. Service List

SCE is serving this Application and its exhibits on all parties on the Commission's service list for proceeding R.02-06-001.

VII.

CONCLUSION

SCE has attached to this application all of the data required to support it and will provide orally or in writing any other information the Commission finds necessary to act on it. SCE respectfully requests that the Commission review this application on an expedited basis, according to the schedule proposed above.

Dated this 29th day of March, 2005, at Rosemead, California.

Respectfully submitted,

SOUTHERN CALIFORNIA EDISON COMPANY

By: Pamela A. Bass
Senior Vice President

MICHAEL D. MONTOYA
JENNIFER R. HASBROUCK
LAURA GENAO

By: Jennifer R. Hasbrouck
Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

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Rosemead, California 91770
Telephone: (626) 302-1040
Facsimile: (626) 302-7740
E-mail: jennifer.hasbrouck@SCE.com

March 29, 2005

VERIFICATION

I am an officer of the applicant corporation herein, and am authorized to make this verification on its behalf. I am informed and believe that the matters stated in the foregoing document are true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed this **29th day of March, 2005**, at Rosemead, California.

Pamela A. Bass
Senior Vice President
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770

CERTIFICATE OF SERVICE

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have this day served a true copy of **SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) APPLICATION FOR APPROVAL OF ADVANCED METERING INFRASTRUCTURE DEPLOYMENT STRATEGY AND COST RECOVERY MECHANISMS** on all parties identified on the attached service list(s). Service was effected by one or more means indicated below:

☐ Transmitting the copies via e-mail to all parties who have provided an e-mail address. First class mail will be used if electronic service cannot be effectuated.

☐ Placing the copies in sealed envelopes and causing such envelopes to be delivered by hand or by overnight courier to the offices of the Commission or other addressee(s).

☐ Placing copies in properly addressed sealed envelopes and depositing such copies in the United States mail with first-class postage prepaid to all parties.

☐ Directing Prographics to place the copies in properly addressed sealed envelopes and to deposit such envelopes in the United States mail with first-class postage prepaid to all parties.

Executed this 30th Day of March, 2005, at Rosemead, California.

____

Meraj Rizvi
Case Analyst
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770

SOUTHERN CALIFORNIA
EDISON
An *EDISON INTERNATIONAL* Company

Jennifer R. Hasbrouck
Senior Attorney
jennifer.hasbrouck@sce.com

March 30, 2005

Docket Clerk
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, California 94102

RE: A.05-03-___

Dear Docket Clerk:

Enclosed for filing with the Commission are the original and eight copies of the **SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) APPLICATION FOR APPROVAL OF ADVANCED METERING INFRASTRUCTURE DEPLOYMENT STRATEGY AND COST RECOVERY MECHANISMS** in the above-referenced proceeding.

We request that a copy of this document be file-stamped and returned for our records. A self-addressed, stamped envelope is enclosed for your convenience.

Your courtesy in this matter is appreciated.

Very truly yours,

Jennifer R. Hasbrouck

JRH:LW050680017.doc
Enclosures

cc: All Parties of Record in R.02-06-001
(U 338-E)

APPENDIX A
Southern California Edison Company's Balance Sheet and Income Statement

SOUTHERN CALIFORNIA EDISON COMPANY

BALANCE SHEET

DECEMBER 31, 2004

A S S E T S

(Millions of Dollars)

UTILITY PLANT:	
Utility plant, at original cost	$17,041
Less - Accumulated depreciation and decommissioning	(4,506)
	12,535
Construction work in progress	789
Nuclear fuel, at amortized cost	151
	13,475
OTHER PROPERTY AND INVESTMENTS:	
Nonutility property, at cost - less accumulated provision for depreciation of $34	583
Property of variable interest entities - net	377
Nuclear decommissioning trusts, at cost	2,757
Other Investments	170
	3,887
CURRENT ASSETS:	
Cash and equivalents	122
Restricted cash	61
Receivables, including unbilled revenues, less reserves of $31 for uncollectible accounts	938
Fuel inventory	8
Materials and supplies	188
Accumulated deferred income taxes - net	134
Regulatory assets	553
Prepayments and other current assets	72
	2,076
DEFERRED CHARGES:	
Regulatory assets	3,285
Other deferred charges	567
	3,852
	$23,290

SOUTHERN CALIFORNIA EDISON COMPANY

BALANCE SHEET

DECEMBER 31, 2004

CAPITALIZATION AND LIABILITIES

(Millions of Dollars)

CAPITALIZATION:	
Common stock	$2,168
Additional paid-in capital	350
Accumulated other comprehensive loss	(17)
Retained Earnings	2,020
Common shareholder's equity	4,521
Preferred stock without mandatory redemption requirements	129
Preferred stock with mandatory redemption requirements	139
Long-term debt	5,225
	10,014
CURRENT LIABILITIES:	
Preferred stock to be redeemed within one year	9
Long-term debt due within one year	246
Short-term debt	88
Accounts payable	700
Accrued taxes	357
Accrued interest	115
Customer deposits	168
Book overdrafts	232
Regulatory liabilities - net	490
Other current liabilities	643
	3,048
DEFERRED CREDITS:	
Accumulated deferred income taxes - net	2,865
Accumulated deferred investment tax credits	126
Customer advances and other deferred credits	510
Power purchase contracts	130
Accumulated provision for pensions and benefits	417
Asset retirement obligations	2,183
Regulatory liabilities	3,356
Other long-term liabilities	232
	9,819
Minority interest	409
	$23,290

SOUTHERN CALIFORNIA EDISON COMPANY

STATEMENT OF INCOME

YEAR ENDED DECEMBER 31, 2004

(Millions of Dollars)

OPERATING REVENUE	$8,448
OPERATING EXPENSES:	
Fuel	810
Purchased power	2,332
Provisions for regulatory adjustment clauses - net	(201)
Other operation and maintenance expenses	2,457
Depreciation, decommissioning and amortization	860
Property and other taxes	177
Total operating expenses	6,435
OPERATING INCOME	2,013
Interest and dividend income	20
Other nonoperating income	84
Interest expense - net of amounts capitalized	(409)
Other nonoperating deductions	(69)
INCOME BEFORE TAX AND MINORITY INTEREST	1,639
INCOME TAX	438
MINORITY INTEREST	280
NET INCOME	921
DIVIDENDS ON PREFERRED STOCK - NOT SUBJECT TO MANDATORY REDEMPTION	6
EARNINGS AVAILABLE FOR COMMON STOCK	$915

APPENDIX B
List of Cities and Counties

SOUTHERN CALIFORNIA EDISON COMPANY

Citizens or some of the citizens of the following counties and municipal corporations will or may be affected by the changes in rates proposed herein.

COUNTIES			
Fresno	Kings	Orange	Tuolumne*
Imperial	Los Angeles	Riverside	Tulare
Inyo	Madera	San Bernardino	Ventura
Kern	Mono	Santa Barbara	

MUNICIPAL CORPORATIONS				
Adelanto	Cudahy	La Habra	Ojai	Santa Monica
Agoura Hills	Culver City	La Habra Heights	Ontario	Santa Paula
Alhambra	Cypress	La Mirada	Orange	Seal Beach
Aliso Viejo	Delano	La Palma	Oxnard	Sierra Madre
Apple Valley	Desert Hot Springs	La Puente	Palm Desert	Signal Hill
Arcadia	Diamond Bar	La Verne	Palm Springs	Simi Valley
Artesia	Downey	Laguna Beach	Palmdale	South El Monte
Avalon	Duarte	Laguna Hills	Palos Verdes Estates	South Gate
Baldwin Park	El Monte	Laguna Niguel	Paramount	South Pasadena
Barstow	El Segundo	Laguna Woods	Perris	Stanton
Beaumont	Exeter	Lake Elsinore	Pico Rivera	Tehachapi
Bell	Farmersville	Lake Forest	Placentia	Temecula
Bell Gardens	Fillmore	Lakewood	Pomona	Temple City
Bellflower	Fontana	Lancaster	Port Hueneme	Thousand Oaks
Beverly Hills	Fountain Valley	Lawndale	Porterville	Torrance
Bishop	Fullerton	Lindsay	Rancho Cucamonga	Tulare
Blythe	Garden Grove	Loma Linda	Rancho Mirage	Tustin
Bradbury	Gardena	Lomita	Rancho Palos Verdes	Twentynine Palms
Brea	Glendora	Long Beach	Rancho Santa Margarita	Upland
Buena Park	Goleta	Los Alamitos	Redlands	Victorville
Calabasas	Grand Terrace	Lynwood	Redondo Beach	Villa Park
California City	Hanford	Malibu	Rialto	Visalia
Calimesa	Hawaiian Gardens	Mammoth Lakes	Ridgecrest	Walnut
Camarillo	Hawthorne	Manhattan Beach	Rolling Hills	West Covina
Canyon Lake	Hemet	Maywood	Rolling Hills Estates	West Hollywood
Carpinteria	Hermosa Beach	McFarland	Rosemead	Westlake Village
Carson	Hesperia	Mission Viejo	San Bernardino	Westminster
Cathedral City	Hidden Hills	Monrovia	San Buenaventura	Whittier
Cerritos	Highland	Montclair	San Dimas	Woodlake
Chino	Huntington Beach	Montebello	San Fernando	Yorba Linda
Chino Hills	Huntington Park	Monterey Park	San Gabriel	Yucaipa
Claremont	Indian Wells	Moorpark	San Jacinto	Yucca Valley
Commerce	Industry	Moreno Valley	San Marino	
Compton	Inglewood	Murrieta	Santa Ana	
Corona	Irvine	Newport Beach	Santa Barbara	
Costa Mesa	Irwindale	Norco	Santa Clarita	
Covina	La Canada Flintridge	Norwalk	Santa Fe Springs	

***SCE provides electric service to a small number of customer accounts in Tuolumne County and is not subject to franchise requirements.**