SOUTHERN CALIFORNIA
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January 12, 2005

Docket Clerk
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, California 94102

RE: R.02-06-001 – Advanced Metering, Demand Response and Dynamic Pricing OIR

Dear Docket Clerk:

Enclosed for filing with the Commission are the original and five copies of the **SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) REVISED PRELIMINARY ANALYSIS OF ADVANCED METERING INFRASTRUCTURE BUSINESS CASE** 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,

J Hasbrouck

Jennifer R. Hasbrouck

JRH:LW050120013.doc
Enclosures

cc: All Parties of Record in R.02-06-001
(U 338-E)

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking on Policies and Practices for Advanced Metering, Demand Response, and Dynamic Pricing.	R.02-06-001 (Filed June 6, 2002)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) REVISED PRELIMINARY ANALYSIS OF ADVANCED METERING INFRASTRUCTURE BUSINESS CASE

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Dated: January 12, 2005

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on Policies and Practices for Advanced Metering, Demand Response, and Dynamic Pricing.	R.02-06-001 (Filed June 6, 2002)

<u>SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) REVISED PRELIMINARY ANALYSIS OF ADVANCED METERING INFRASTRUCTURE BUSINESS CASE</u>

In accordance with the directives of the Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure issued on July 21, 2004 (Ruling) and 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, Southern California Edison Company (SCE) hereby submits its Revised Preliminary Analysis of Advanced Metering Infrastructure (AMI) Business Case for review by the California Public Utilities Commission (Commission).

SCE has organized its revised preliminary analysis into four volumes. Volume 1 focuses on SCE's business vision and management philosophy, preliminary results, and overarching policy considerations. In Volume 2, SCE discusses its approach, including SCE's Business As Usual case, as well as its general assumptions on technology, demand response, rate design and bill impact, and financial implications. SCE further provides in Volume 2 its general risk assessment concerning existing uncertainties. Volume 3 sets forth SCE's revised preliminary analysis of all of the full deployment business case scenarios on a scenario-by-scenario basis and a preliminary analysis of the revenue requirement. Similarly, in Volume 4, SCE presents its revised preliminary analysis for the partial deployment scenarios, as well as a preliminary revenue requirement.

SCE's revised preliminary analysis attempts to address each of the requirements of the Ruling's analytical framework, including performing the analysis for the numerous required scenarios. SCE anticipates that there could be a number of changes and refinements to this analysis when the final application is submitted. As such, SCE submits this revised preliminary analysis for the Commission's preliminary review.

Respectfully submitted,

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January 12, 2005

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) REVISED PRELIMINARY ANALYSIS OF ADVANCED METERING INFRASTRUCTURE BUSINESS CASE** on all parties identified on the attached service list(s). Service was effected by one or more means indicated below:

- ☐ Placing the copies in properly addressed sealed envelopes and depositing such envelopes in the United States mail with first-class postage prepaid (Via First Class Mail):
  - ☐ To all parties, or
  - ☑ To those parties without e-mail addresses or whose e-mails are returned as undeliverable;
- ☐ 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 the other addressee(s);
- ☑ Transmitting the copies via e-mail to all parties who have provided an address.

Executed this **12th January, 2005**, at Rosemead, California.

MRizvi

Meraj Rizvi
Project Analyst
SOUTHERN CALIFORNIA EDISON COMPANY

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Proceeding No.: R.02-06-001
Document No.: SCE-1

SOUTHERN CALIFORNIA
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(U 338-E)

Advanced Metering Infrastructure Revised Preliminary Business Case Analysis

Volume 1 – Vision Statement, Summary of Revised Preliminary Business Case Analysis, and Policy Considerations

Before the
Public Utilities Commission of the State of California

Rosemead, California
January 12, 2005

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) REVISED PRELIMINARY ANALYSIS OF ADVANCED METERING INFRASTRUCTURE BUSINESS CASE

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I.

INTRODUCTION

This filing revises Southern California Edison Company's "Advanced Metering Infrastructure Business Case Preliminary Analysis" filed on October 22, 2004. This filing complies with Ordering Paragraph 1 of 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. In accordance with that Ruling, we have revised our October 22, 2004 filing analysis based on updated information. Due to time constraints and the fact that many of the required scenarios will be eliminated for the formal application in March 2005, our primary focus in preparing this revised preliminary analysis was to update and correct cost and benefit data in our October 22, 2004 filing. As such, SCE has not undertaken radical modifications to its original preliminary analysis submitted in October 2004, but rather targeted completing and updating the original preliminary analysis through this revision.

The purpose of Volume 1 is to describe our underlying management philosophy and business vision, plus overarching policy considerations that will guide any deployment of Advanced Metering Infrastructure (AMI), 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 (Ruling). In Section II of this volume, we describe the business vision that helped shape our analysis of the costs and benefits associated with a full or partial deployment of AMI. Consistent with the Ruling, we also address our view of expected regulatory decisions and expectations of the future business and financial environment, as well as the potential large scale deployment risks that will have a fundamental bearing on the costs and benefits of AMI. Equally important as those items identified in the Ruling, we discuss in our business vision the expected operational and financial impacts that a wide-scale deployment of AMI will have on our customers during the Ruling's sixteen-year analysis period.

In Section III of Volume 1, we set forth the results of our analysis to date. In this section, we summarize the total costs, total benefits, and net present value of each of the seventeen unique business case scenarios that we have analyzed and described in detail in Volumes 3 (full deployment) and 4 (partial deployment). Section III of Volume 1 also provides our observations on the results of the cost-benefit analysis as related to the potential deployment of AMI.

Section IV of this volume sets forth our overarching policy considerations regarding the deployment of AMI. Specifically, Section IV discusses what events need to occur for AMI to be successful, including necessary policies to ensure that reliable demand response benefits materialize and that significant constraints and uncertainties are resolved.

II.

SCE'S MANAGEMENT PHILOSOPHY AND BUSINESS VISION CONCERNING THE ROLE OF ADVANCED METERING INFRASTRUCTURE

In the Ruling, the Commission ordered each utility to describe its underlying management philosophy or 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.[1]

The underlying management philosophy that has helped shape our analysis of AMI is consistent with the management philosophy and vision that guide 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 and vision 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 and business vision has shaped our business

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[1] 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.").

case analysis of AMI to date and will continue to influence the development of our AMI strategy and proposal.

In concert with this management philosophy, there are three important fundamental principles that should help guide the evaluation of whether AMI and price-induced demand response make sense for our customers: (1) the program must be cost effective and deliver benefits to customers, (2) the dynamic pricing rate structures must be based on actual costs or prices prevailing in a functioning and appropriate market, and (3) the program should ideally allow for customers to make choices among tariffs. Consistent with these principles, we are exploring alternative AMI technologies and capabilities similar to those in the Enel deployment in Italy.

A. <u>SCE Pursues Investments When They Are Cost Effective and Deliver Benefits To Our Customers</u>

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 adopt immediately every technical improvement that comes along. The question of upgrading technology must look beyond the current or even next generation of technology, and anticipate even further improvements. By applying this principle, we have and continue to make cost-effective technology improvements and upgrades in many areas, including metering.

AMI couples 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[2] to serve an important role in meeting our customers' capacity needs. We are confident that in time, cost-effective and reliable dynamic pricing[3] and market/economic-triggered demand response programs[4] will also play an important role in balancing California's electricity supply/demand equation. We believe that cost-effective demand response to time-differentiated rates will be a vital element in an optimal procurement portfolio.

We have evaluated this AMI business case as we have other ratepayer investments of a similar magnitude. We have taken great care in evaluating both the cost and benefit side of the equation and applied a net present value of cash flow method as we do for other types of 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 preliminary stage.

1. **<u>SCE Pursues New Technology and Processes that Provide Increased Operational Efficiency</u>**

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 a leader 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

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[2] By "reliability-based demand response," SCE refers to demand curtailment programs that do not have a price-responsive element and instead are activated upon system emergency, such as the interruptible programs.

[3] By "dynamic pricing," SCE refers 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.

[4] By "market/economic-triggered demand response," SCE refers to direct load control and load curtailment programs that can be activated in response to market prices, such as the demand bidding program.

Meter Reading (AMR) program, which targets those meters that are hardest 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 response.[5] 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 the "energy orb" to provide pricing information to our customers.[6]

In addition, we have invested (and continue to invest) 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 and identifies potential problems and allows a quick response to reliability events.[7] We have already invested in highly effective outage management and transformer load management systems that are 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

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[5] We previously proposed a major expansion of our successful air conditioner cycling load control program in the Long-Term Procurement Plan submitted in R.04-04-003 and in SCE's Demand Response Program Proposals for 2005-2008, submitted in R.02-06-001 on October 15, 2004.

[6] *See* SCE's Demand Response Program Proposals for 2005-2008, submitted in R.02-06-001 on October 15, 2004.

[7] 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.

investments in these successful operational systems, we are already reaping the benefits that these systems deliver and thus, additional investment in AMI may not provide significant value resulting from these types of operational benefits.

We recognize, as does the Commission and other parties to this proceeding, 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, an essential question in this proceeding is whether a large-scale investment in the AMI technology of today will maximize ratepayer benefit or would such investment now end up costing ratepayers more due to today's less certain technology and the lost opportunity to capitalize on improved or less expensive technology in the future. We understand that there are promising technological advancements on the horizon. As such, we are exploring alternative AMI technologies, similar to the Enel experience, that may lower price points.

2. <u>Demand Response Resources Must Be Cost Effective in Relation to Other Resources</u>

The Commission has endorsed the multi-agency "Vision of Demand Response,"[8] which, in several important respects, mirrors SCE's own business vision and philosophy concerning the proper role of AMI. The preamble to the Vision states:

> "[t]his vision … 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."[9]

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[8] D.03-06-036, Attachment A, "California Demand Response: A Vision of the Future."

[9] *Id.,* p. 1.

This initial statement is essential to developing an overall policy concerning demand response in California, as the focus is on attaining the optimal mix of resources, not simply promoting one resource over another. The Vision importantly recognizes that the highest attainable level of demand response may not be the most desirable if it results in the inefficient use of resources, harms the state's economy, and/or adversely impacts the comfort and well-being of customers. We agree that demand response should not come at the cost of unreasonable decreases in customer comfort and well-being or a disproportionate impact on certain customer segments. We also agree with the Vision's notion that "cost-effective" may not equal "least cost" and that ultimately, the goal should be the most efficient use of resources.

The Vision's preamble further states:

> "demand response is one resource among many that may be procured by utilities on behalf of their electric customers. We also seek to make the most cost-effective investments from an overall societal perspective."[10]

Again, this is a key recognition that although demand response shows great promise, it is just one piece of the puzzle in solving California's electricity supply and demand problems. It is important that policy-makers recognize this fact and balance the appropriate level of price-induced demand response with parallel efforts (including, for example, demand reductions from energy efficiency measures, advanced load control, *etc.* and supply-side resources such as new generation, including distributed generation, renewables, *etc.*) so that the most efficient mix of these resources is attained.

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[10] *Id.*

SCE's own management philosophy is allied with these elements of the multi-agency Vision, in that we believe that cost-effective demand response does have an important role among the resource options, and that the costs and benefits of demand response and AMI must be evaluated in comparison to the other resources. However, the Commission, State Agencies, and the utilities will need to address a number of important policy considerations, as discussed below in Section IV.

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 programs such as advanced load control. Simply put, these other resources are generally 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.[11]

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

[11] 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.

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 will be subject to the generation pricing of their city or energy supplier which 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.[12]

B. Dynamic Pricing Rates Must Be Cost or Market-Based

The success of AMI relies on benefits from demand response achieved through dynamic time-differentiated rates. Assessing the value of these benefits requires the consideration of whether this type of resource will lower the peak market prices and avoid the cost of additional generation capacity and energy. 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 rates being cost-based, dynamic pricing rates should provide a sufficient bill reduction when customers reduce or shift electricity usage to low-cost

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[12] The development of a functional energy market is an important unknown that must be resolved before AMI can be successful. *See* Volume 2, Section IV.D.

hours. Many customers could "lose" on dynamic rates, with higher bills despite the same or even reduced demand levels.[13] 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.[14]

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, for AMI to become successful, it will be imperative that a functional wholesale market is operating from which we can develop appropriate cost-based retail rates.

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[13] For example, our preliminary 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* Volume 2, Section III.C.

[14] 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.

C. Customers Should Be Informed and Allowed To Make Choices Among Tariffs

Our revised preliminary business case analysis discussed below establishes that an AMI deployment at any level will ultimately depend on significant and reliable demand response benefits to justify the cost. 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. Achieving significant and persistent demand response would likely require that all customers take service on a tariff involving time-differentiated rate structures.

We have long supported the underlying principle of providing customers with several rate options from which they can choose. SCE's success in its long history of reliability-based programs has focused on voluntary customer participation. We continue to believe that, ideally, customers should have the choice of rate options. However, to the extent that an AMI deployment depends on demand response benefits, the choice of alternatives may have to be narrowed to more dynamic rate structures. This is a difficult and contentious policy issue for regulators. In order to obtain the demand response that will make AMI cost effective, policy makers must be willing to take an aggressive approach to make time-differentiated rates the default rate, which may be very unpopular with certain customer groups. For example, low-income customers on the CARE or FERA rate may have little discretionary electrical usage and may experience increased bills from the imposition of default time-differentiated rates. Further, regulators cannot waiver from this path over the long term, even when prices fluctuate or increase due to market conditions.

To realize economic benefit from demand response, two components are essential. First, customers must change behaviors to reduce peak usage and second, the utility must be able to rely on that behavior to avoid the cost of capacity and energy supplies. Just placing customers on time-differentiated rates will not necessarily create the desired demand response nor will it necessarily fully equate to avoided utility procurement costs.[15]

There are two essential elements to achieve and sustain behavioral change. The first is customer education and awareness: If customers are not aware of the mechanics of the rate they have been placed on – and what they can do to save money – they obviously will not change behaviors. The second element is an economic incentive: Customers must be able to see results from their actions in the form of reduced bills in order to sustain their new behavior. Without substantial education and the economic incentive, even default time-differentiated rates will not produce the requisite level and persistence of demand response to justify an AMI investment.

We prefer that customers be offered a choice of rates, including time-differentiated, flat and tiered, as well as load control options. Customers should be empowered to understand their options and make the right choices. However, in order to obtain sufficient demand response to justify an AMI investment, customers may need to be defaulted to time-differentiated rates, with opt-out alternatives to other time-variant rates.

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[15] Because electric energy cannot be stored in large amounts cost-effectively, utilities must procure in advance sufficient capacity and energy to meet anticipated loads. Decisions on supply procurement are therefore time-dependent and must rely on forecasted requirements. Demand response, by nature, is less predictable as a resource than turning on a combustion turbine and therefore reasonable operations require that a probability adjustment be made to equilibrate demand response with a supply resource. Moreover, tariffs such as critical peak pricing can reduce the value of demand response to the utility's procurement function by limiting the availability of the resource to a fixed number of events per season or by requiring day-ahead notice of events in a way that prevents adjustment for unexpected intra-day changes in weather.

III.

SUMMARY OF AMI BUSINESS CASE REVISED PRELIMINARY ANALYSIS

A. Summary of Revised Preliminary Results of Business Case Scenarios

The Ruling required that we perform at least seventeen unique business case analyses for various operational and demand response scenarios. Eight of these required scenarios involved full deployment of AMI to customers with demand below 200kW[16] and nine involved partial deployment. Four of these required scenarios assume no implementation of demand response programs using the advanced meters, so the only benefits are associated with operational savings, such as reduced meter reading expenses. Two of these four operational-only scenarios involve outsourcing of AMI to a third-party supplier. Other scenarios investigate different types of time-differentiated rates enabled by AMI that might be implemented, including various forms of critical peak pricing (CPP) and time-of-use (TOU) rates. Among those scenarios are those that assess the impact of demand response from time-differentiated rates and reliability programs such as load control. Finally, to comply with the Ruling's requirement to assess the cost and benefit of real-time pricing (RTP) for large customers (>200kW in demand) that already have, or will have, RTEM meters, we prepared two additional business case scenarios so that this effect could be evaluated separately or in combination with

[16] SCE has already installed communicating interval meters for most customers with demand above 200kW. As such, there are no associated costs of AMI for these customers and these customers are not included in the actual AMI deployment plans, even though, per the Ruling, the increased demand response benefits from these customers are included in the cost effectiveness analysis. We have already requested that the Commission address the ongoing "clean up" issue of interval meter deployment to large customers as part of our 2005-2008 Demand Response Proposal and thus, any costs associated with any new interval meters to customers with demand greater than 200 kW is considered to be part of "Business As Usual" outside of the incremental AMI analysis.

any of the required scenarios. One scenario evaluates the effect of RTP applied to all large customers. To provide a "reliability" component of the large-customers, we include another scenario that assumes our Schedule I-6 interruptible program is maintained and all other large customers are place on an RTP rate.

The Ruling's Analysis Parameters included the assessment of uncertainty and risk in both a quantitative (such as with Monte Carlo simulation techniques) and qualitative manner.[17] 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.[18] The methodology employed is described in Volume 2 and the quantitative results are presented in Volumes 3 and 4. We also prepared a qualitative assessment of risk factors that is described in Volume 2.

In our October 22, 2004 filing, we included five alternative AMI business case scenarios for consideration.[19] Those analyses did not provide better net present value (NPV) results than the required cases, although they did offer an alternative view of customer enrollment effects and avoided cost value assumptions. For this revised preliminary analysis, we have not pursued these alternative scenarios, although we may incorporate assumptions used in them in our March 15, 2005 application.

In all, we have completed a revised preliminary analysis of seventeen separate business case scenarios. 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 these scenarios is presented below. The summary of the revised

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[17] Ruling, pp. 12-13.

[18] Monte Carlo simulations were performed on costs for all scenarios. A Monte Carlo simulation for demand response benefits was prepared for only Scenario 4. The results of these simulations are presented in Volumes 3 and 4.

[19] SCE's alternative scenarios in the October 22, 2004 submittal were Scenarios 9, 10, 11, 22, and 23.

preliminary business case analysis of our full deployment scenarios is set forth in Table 1-1 and the revised preliminary business case analysis of our partial deployment scenarios is set forth in Table 1-2 below.

Table 1-1
Summary of Revised Preliminary Results – Full Deployment Scenarios
(in millions 2004 Present Value dollars)

No.	Scenario Description	Details	Total Costs	Total Benefits	After-Tax NPV	Rev. Req. NPV
1	Operational Only	Utility Implementation – Current Tariff	$(901.9)	$430.6	$(376.3)	$(918.4)
2*	Operational Only	Outsourced Implementation – Current Tariff	N/A	N/A	N/A	N/A
3	Operational + Demand Response	TOU Default with 20% opt-out	$(1,212.3)	$571.3	$(481.1)	(1,094.1)
4	Operational + Demand Response	CPP-F/CPP-V Default with 20% opt-out	$(1,233.9)	$805.0	$(355.0)	$ (882.2)
5	Operational + Demand Response	Current Tariff with opt-in to CPP-Pure	$(1,150.2)	$605.8	$(423.6)	$(996.7)
6	Operational + Demand Response	Current Tariff with opt-in to CPP-F/CPP-V	$(1,150.2)	$603.1	$(425.2)	$(999.4)
7	Operational + Demand Response + Reliability	CPP-F/CPP-V Default with 20% opt-out plus load control	$(1,340.6)	$963.4	$(324.3)	$(831.8)
8	Operational + Demand Response + Reliability	Current Tariff with opt-in to CPP-Pure plus load control	$(1,411.1)	$995.3	$(347.2)	$(871.2)

* The outsourcing analysis cannot be represented in terms of the same cost, benefit, and NPV figures due to the nature of the cost information provided by vendors. The details of the Scenario 2 analysis are set forth in Volume 3, Section III.B.

As indicated above, none of the scenarios establish that a full deployment of AMI is currently cost effective using the required assumptions. The most favorable cases are Scenarios 7 and 8, which include dynamic pricing on a default enrollment basis with SCE's proposed reliability program.[20] Yet, even the most favorable scenario, Scenario 7, has a negative revenue requirement present value of $(324) million, and a negative revenue requirement impact of more than $800 million (2004 present value).

For full deployment to have a positive NPV, either costs must decrease or benefits must increase substantially. It is more likely at the present time, however, that costs and benefits will go in the other direction. On the cost side, it is more likely that costs will be higher rather than lower because the technology envisioned by the Ruling is unproven and not commercially available at this time. In time, costs could decline as the technology matures. On the benefit side, absent mandatory participation, it is hard to envision more demand response benefits than assumed in Scenario 4, for example, where eighty percent of customers default to CPP rates for the duration of the study. Moreover, the demand response benefits assume avoided cost values prescribed by the Ruling that we believe are inappropriately high for a limited resource. We performed a Monte Carlo simulation for this scenario with what we believe are more proper avoided cost values which is described in Volume 3. Our Monte Carlo analysis found that the demand response benefit declined by more than 40 percent from the benefit computed using the Ruling's assumption for avoided costs. Scenario 7 has the highest demand response benefits, but many of those benefits accrue from Advanced Load Control, which could be implemented without AMI.

As required by the Ruling, we also developed revised preliminary business case analyses for partial deployment scenarios. We have developed two separate, but potentially complementary partial deployment strategies, with various

[20] Although Scenarios 7 and 8 have the best overall results of those analyzed, these demand response savings are due, in part, to the Advanced Load Control program benefits, which could be obtained on a stand-alone basis. Moreover, absent the "crowding out" effect of AMI, the potential demand savings from Advanced Load Control could be even greater.

scenarios for each strategy. The first strategy would be to modify the default rate for RTEM customers with demands greater than 200kW from the current TOU default to an RTP rate in order to maximize demand response benefits from customers that already have interval metering. This approach, however, is not strictly an "AMI deployment" because it relies on meters already installed. The second strategy is a scaled-down version of the full deployment limited to SCE's Climate Zone 4.[21] The summary of the various partial scenarios for each strategy is presented below in Table 1-2.

[21] Climate Zone 4 was developed as part of the Statewide Pricing Pilot's climate zones and is the very hot, desert areas of SCE's service territory, with approximately 450,000 SCE customers.

Table 1-2 Summary of Revised Preliminary Results – Partial Deployment Scenarios (in millions of 2004 Present Value dollars)						
No.	**Scenario Description**	**Details**	**Total Costs**	**Total Benefits**	**After-Tax NPV**	**Rev. Req. NPV**
12	Demand Response	RTP Default Tariff for all RTEM >200kW	$(17.9)	$255.3	$141.0	$237.1
13	Demand Response + Reliability	RTP Default Tariff for all RTEM >200kW plus load control	$(373.3)	$504.0	$77.6	$ 126.2
14	Operational Only	Zone 4 - Utility Implementation – Current Tariff	$(157.9)	$41.8	$(80.2)	$ (173.2)
15*	Operational Only	Zone 4 - Outsourced Implementation – Current Tariff	N/A	N/A	N/A	N/A
16	Operational + Demand Response	Zone 4 - TOU Default with 20% opt-out	$(242.2)	$64.4	$(117.9)	$ (236.4)
17	Operational + Demand Response	Zone 4 - CPP-F/CPP-V Default with 20% opt-out	$(245.9)	$90.0	$(104.9)	$ (214.6)
18	Operational + Demand Response	Zone 4 - Current Tariff with opt-in to CPP-Pure	$(239.4)	$68.8	$(113.6)	$ (229.2)
19	Operational + Demand Response	Zone 4 - Current Tariff with opt-in to CPP-F/CPP-V	$(239.4)	$70.8	$(112.5)	$ (227.2)
20	Operational + Demand Response + Reliability	Zone 4 - Current Tariff with opt-in to CPP-Pure plus load control	$(549.2)	$518.3	$(45.1)	$ (117.8)
21	Operational + Demand Response + Reliability	Zone 4 - Current Tariff with opt-in to CPP-F/CPP-V plus load control	$(549.2)	$520.3	$(43.9)	$ (115.8)

* The outsourcing analysis cannot be represented in terms of the same cost, benefit, and NPV figures due to the nature of the cost information provided by vendors. The details of the Scenario 15 analysis are set forth in Volume 4 Section IV.B.

Most of the partial deployment scenarios also prove not to be cost effective. As indicated above, the NPV is positive for Scenarios 12 and 13 concerning increased demand response benefits for existing RTEM customers. For the partial AMI deployment scenarios, we selected Zone 4 as the appropriate area of our service territory to perform the partial deployment analysis because the 2003 SPP results indicated that it was the climate zone that would result in higher demand response levels. In addition, a concentrated deployment in a specific geographic region has potentially higher deployment efficiency when compared to a less concentrated deployment throughout our entire service territory (*e.g.*, targeting higher-usage customers across the service territory). Our NPV analysis, however, indicates that the Zone 4 partial deployment scenarios are not cost effective today given the current cost and benefit estimates.

For demand response benefits of both full and partial deployment scenarios, 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 those results in the tables above.[22]

B. Summary of SCE's Preliminary Position on AMI

As the tables above establish, the revised preliminary analysis for each of the seventeen business case scenarios indicates that none of the scenarios requiring AMI meter deployment has a positive NPV, meaning that none of the Ruling's required AMI deployment scenarios appears to be cost effective for our customers at this time. Only the two scenarios involving dynamic rate changes for the RTEM customers with demands greater than 200 kW proved to be cost effective. The details of this revised preliminary business case analysis, including the specific costs, benefits, and uncertainties on a scenario-by-scenario basis are presented in Volumes 3 (full deployment) and 4 (partial deployment).

Our revised preliminary analysis demonstrates that all of the Ruling's required AMI business case scenarios have extremely negative outcomes on a net

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[22] *See* Volume 2, Appendix B.

present value basis. From these preliminary findings, it is clear that "tweaks" to the analysis or to underlying assumptions will not make a substantial difference in the outcome. In fact, even in the best full deployment case (Scenario 7), meter costs for residential customers would have to decrease significantly to even come close to breakeven range. This is because the operational savings plus expected demand response benefits simply do not offset the net operational costs of full deployment as assumed in the framework. A complete redesign or rethinking of AMI or waiting until AMI technology matures and costs decrease significantly is required before an investment in a widescale AMI deployment will be cost effective. To this point, we have not identified a viable AMI deployment strategy that will provide quantifiable benefits, but we are exploring alternative AMI technologies and capabilities that may lower price points.

Ultimately, this proceeding may conclude that the high level of risk and uncertainty of AMI warrants a more cautious approach, such as a delay in the deployment schedule until policy, legislative and technology uncertainties are resolved.[23] In order to open up the possibility of a cost-effective AMI deployment in the future, we hope that this proceeding will focus on resolving the uncertainties and challenges currently facing AMI. We realize that price-responsive demand response has an important role to play in the utilities' procurement portfolios and we believe that AMI, in time, may be able to facilitate this important demand response resource. However, the timing and scale of an AMI investment will be important factors in determining whether AMI is the right investment for our customers.

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[23] *See* Volume 2, Section IV.

IV.

OVERARCHING POLICY CONSIDERATIONS

As noted above, our revised preliminary analysis using the Ruling's required assumptions for AMI demonstrates that it is not yet cost effective. It is essential and prudent to use realistic assumptions. Under realistic assumptions, the negative outcomes of the business case analysis are, in a word, insurmountable at this time without radical changes to the underlying assumptions and cost structures of today's AMI technology. However, even with the most favorable assumptions and the best net present values from our projected range of results, there are a number of underlying policy considerations that must be addressed, as discussed below.

A. Appropriate Rates Must Be Mandated for AMI to Be Successful

For an AMI business case to work at any level, the Commission must establish the appropriate policies to justify the investment. For SCE, AMI is not even near cost effective without significant demand response benefits. A commitment to optimize the level of demand response from an interval metering investment must be in place before the investment is made, otherwise, there will be significant risk that necessary benefits will not materialize. If California goes down the path of building the infrastructure to support dynamic pricing tariffs, the Commission must be prepared to make the hard decisions so that the requisite levels of demand response will materialize and can be sustained. Without appropriate policies in place to allow reliable demand response savings to occur, AMI will likely not be the right investment choice for ratepayers. With a commitment, the likelihood of sustained demand response benefits improves, along with the chances of success of AMI. We commit to continuing to work with the

Commission in this proceeding to develop a workable and sustainable policy that achieves reliable demand response reductions without harming California's businesses and residents.

B. The Legislative Constraints Imposed by AB1-X Must Be Removed for AMI to Be Successful

As alluded to in the Ruling, in the near term, legislative constraints on rate design modifications may have a considerable impact on the benefits derived from the full deployment of AMI.[24] The legislative constraints are the result of Section 80110 of the California Water Code enacted by AB1-X as a result of the 2000-2001 energy crisis. Section 80110 prohibits the Commission from increasing any electricity charge for residential customers' usage of up to 130 percent of the existing baseline allowance. This prohibition is in place until the California Department of Water Resources (CDWR) power contracts expire, which is currently expected to occur in 2013.[25]

As the Ruling recognizes, the rate design restrictions required by Section 80110 will impede the ability to derive substantial demand response benefits under the full deployment scenarios in the years prior to expiration of this constraint. This is because under the statute, rates cannot be designed to respond to critical peak or time-of-use price signals for a residential customer's entire usage, given that 130 percent of customers' baseline usage would not be subject to dynamic pricing. 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

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24 Ruling, p. 3.

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

existing residential customer bills. If Section 80110 remains in place, residential dynamic pricing schedules under a default or mandatory tariff enrollment would not be allowed until 2014, drastically reducing the potential demand response benefits.[26]

As noted above, without substantial demand response benefits, the AMI business case is not cost effective and does not make sense for our ratepayers at this time. Successful AMI deployment will require the elimination of Section 80110, either through legislative repeal of the restriction against mandatory dynamic pricing tariffs for residential customers or through the expiration of the statute under its own terms. Because the potential for success of AMI hinges on the ability to require residential customers to take service under a time-differentiated rate, if the restrictions of Section 80110 cannot be repealed for reasons unrelated to AMI, then the Commission should consider delaying the ultimate decision on whether to move forward with AMI until the elimination of the statutory restrictions is guaranteed.

C. Challenges and Uncertainties Regarding AMI and Dynamic Pricing Demand Response Must Be Resolved for AMI to Be Successful

As discussed more thoroughly in Volume 2, there are a number of substantial challenges surrounding AMI, including technological/vendor risks, customer acceptance, 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 component (the avoided cost benefits from demand reductions) of the preliminary business case analysis. For the various business case scenarios, we

[26] In accordance with Agency Staff direction, the demand response benefit calculations in this preliminary analysis have not taken these statutory restrictions into account.

have performed statistical analyses to attempt to quantify the value of the uncertainty. On a general level, our preliminary analysis indicates that the high degree of uncertainty with the main cost and benefit drivers makes AMI investment more speculative and risky at this time than alternative investments. An important focus of this proceeding will be to define the challenges of AMI and investigate measures that may resolve these uncertainties. We are confident that this proceeding will help resolve some of these uncertainties and provide answers to the ultimate question of when will be the right time to invest in AMI technology and what is the proper technological scope for an AMI deployment.

V.

CONCLUSION

Our revised preliminary business case analysis illustrates that without modification, all of the AMI deployment scenarios under the Ruling's required assumptions are far from being cost effective. The results establish that AMI, as envisioned in the Ruling's framework, is ahead of its time from a ratepayer benefit perspective under reasonable and prudent assumptions. SCE will work with the Commission to further evaluate other approaches and emerging AMI technologies and capabilities, such as the Enel deployment.

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SOUTHERN CALIFORNIA
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(U 338-E)

Advanced Metering Infrastructure Revised Preliminary Business Case Analysis

Volume 2 – Approach and Business as Usual Case Analysis, General Assumptions and Risk Assessment

Before the
Public Utilities Commission of the State of California

Rosemead, California
January 12, 2005

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) REVISED PRELIMINARY ANALYSIS OF ADVANCED METERING INFRASTRUCTURE BUSINESS CASE

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I.

INTRODUCTION

The purpose of Volume 2 is to describe our analytical approach to addressing the requirements of the Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure issued on July 21, 2004, (Ruling) and identify the key assumptions and risk areas that affect the results of this preliminary analysis.

As noted in Volume 1 of this filing, this revised document replaces the Volume 2 document submitted as part of our October 22, 2004 filing. While our overall conclusions have not changed, this document revises our preliminary analysis with corrections to known errors or omissions as indicated in our October 22, 2004 filing and is based on summer 2003 demand response data. The revision also takes into consideration the approaches used by the other utilities as well as comments on the utilities' October 2004 filings by the CEC, CUE and TURN at the November 8, 2004 Working Group 2 meeting. We have maintained a similar general approach as detailed in our October filing, but included a more robust analysis of demand response benefits in the required cases. We also have eliminated the optional cases from our October 22, 2004 filing. The optional cases examined the effect on demand response benefits of different customer adoption rates of TDRs and a different valuation approach for demand response benefits. As discussed later in this volume, we have incorporated these aspects of those optional scenarios within the Monte Carlo simulations of the affected business cases herein.

In Section II of this volume, we describe our overarching approach in conducting the revised preliminary business case analysis and how it addresses the requirements of the Ruling. We have complied with all of the requirements of the Ruling by gathering and compiling cost and benefit information for the seventeen required business scenarios. In addition, as required by the Ruling, the costs and benefits of each scenario were allocated, as appropriate, among five cost categories, eight Start-Up cost codes, forty Installation cost codes, thirty-one Operations and Maintenance (O&M) cost codes, and forty Benefit codes. Consistent with the Ruling, a key part of our analytical approach is the development of our Business As Usual base case, which is also described in Section II.

Section III of this volume includes a discussion of the key assumptions that have shaped this revised preliminary analysis, such as our selected Advanced Metering Infrastructure (AMI) technology solution, key deployment operating parameters, assumptions used in computing demand response benefits, rate design and bill impacts, financial assumptions and cost effectiveness. These fundamental assumptions are common throughout the revised preliminary business case analysis and are reflected in the scenario-by-scenario analyses presented in Volumes 3 and 4. In Section III of this volume, we also provide our view that customer value of service should also be considered in the cost effectiveness analysis. Further, this section provides a high-level description of the revenue requirement necessary to support AMI based on the financial analysis of direct costs and benefits, as well as recovery of stranded costs as a result of replacing existing used and useful assets by the AMI meters and other related systems. The revenue requirement analysis is described in detail in Volumes 3 and 4.

Finally, in Section IV, we describe our assessment of key uncertainties and risks regarding the AMI business case deployment scenarios required by the Ruling. There are a number of substantial uncertainties concerning the primary cost and benefit drivers of the business case that must be resolved for AMI to be successful. In this section, we set forth strategies that could be implemented to mitigate some of the risk associated with these uncertainties.

II.

SCE'S ANALYTICAL APPROACH IN PREPARING THE REVISED AMI BUSINESS CASE PRELIMINARY ANALYSIS

The Ruling's business case framework was designed to address a high degree of uncertainty associated with a substantial investment in AMI deployment including customer response to time-differentiated rates (TDRs). As demonstrated by the sheer size of this revised preliminary filing, we have taken the requirements of the Ruling very seriously by preparing a thorough and comprehensive approach to our revised preliminary analysis, given the unprecedented nature of the AMI deployment contemplated in the Ruling. AMI, as envisioned by the Ruling, includes the capability of supporting widespread customer participation in critical peak pricing (CPP) tariffs, which require hourly usage measurement, daily reporting, and customer event notification. Such an effort has never been implemented to the mass market of a large utility. In addition, a number of TDRs required by the Ruling to be analyzed were not explicitly tested by the Statewide Pricing Pilot (SPP), nor have they been widely implemented elsewhere.[1] Accordingly, the business case framework required by the Ruling was structured to address a variation in key components in the analysis including full and partial deployments, internally financed or outsourced implementation and various combinations of benefits calculations including operational, TDR types and TDR enrollment policies.

In this section, we describe our general analytical approach in preparing the revised preliminary analysis of the business case, as well as our approach to the required Business As Usual base case. Our general approach discussion also

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[1] Real time pricing (RTP), CPP Pure and CPP-Variable (CPP-V) without load control tariff offerings were not explicitly tested by the SPP. Although time-of-use (TOU) was tested in the SPP, the results were not statistically significant for summer 2003.

provides an overview of how we completed the specific scenario-by-scenario analyses presented in Volumes 3 and 4. The description of the Business As Usual scenario is fundamental to understanding our approach because each of the scenarios presented in Volumes 3 and 4 are described as "incremental" to this base case.

A. General Approach

We followed the analytical framework outlined in Attachment A of the Ruling by completing a Business As Usual base case, full and partial AMI deployment business cases, and scenarios involving various tariff and demand benefit assumptions. As specified by the Ruling, the business case analysis was broken down into separate scenarios which build upon earlier scenarios to isolate their differences. The Business As Usual base case is a common reference point for all scenarios, upon which the operational-only scenarios are layered, followed by the various demand response scenarios, and finally the reliability scenarios. Our scenario parameters and assumptions were designed to allow for this building block approach, to the extent possible. Moreover, the commonality of the assumptions between scenarios helps highlight the differences between the various tariff options. The layout and key parameters of each of the scenarios studied in this preliminary analysis are provided in Table 2-1 below:

Table 2-1 Scenario Definitions		
No.	**Benefits**	**Key Parameters**
BAU		Existing advanced metering and communications, existing and planned load control, existing and planned outage management, major exceptions and expected investments. Base case to which other cases are compared to identify if any major investments and other costs/benefits are avoided if AMI is implemented.
1	OP	Full AMI – Operational Only – utility implemented
2	OP	Full AMI – Operational Only – outsourced
3	OP+DR	Full AMI – TOU tariff is default
4	OP+DR	Full AMI – CPP-Fixed (CPP-F) tariff is default for residential, CPP-V default for small Commercial and Industrial (C&I) (Exception: RTP for large customers covered in Scenario 12)
5	OP+DR	Full AMI – Current tariff with opt-in to CPP-Pure tariff (residential and small C&I)
6	OP+DR	Full AMI – Current tariff with Opt-in to CPP-F residential/CPP-V small C&I
7	OP+DR+ REL	Full AMI – CPP-F tariff is default for residential, CPP-V default for small C&I, includes load control for residential customers (Exception: RTP plus load control for large customers covered in Scenario13).
8	OP+DR+ REL	Full AMI – Current tariff with opt-in to CPP-Pure tariff (residential and small C&I) plus Advanced Load Control for residential
9*	OP+DR	Omitted*
10*	OP+DR	Omitted*
11*	OP+DR+ REL	Omitted*
12	OP+DR	Partial AMI: RTP mandatory for C&I customers 200kW or greater
13	OP+DR+ REL	Partial AMI: Same as Scenario 12 except Schedule I-6 interruptible program maintained
14	OP	Partial AMI: Climate Zone (Zone 4) – Operational Only – utility implemented
15	OP	Partial AMI: Operational-Only – outsourced
16	OP+DR	Partial AMI: Zone 4 – TOU tariff is default
17	OP+DR	Partial AMI: Zone 4 – CPP-F tariff is default for residential, CPP-V default for small C&I, no large C&I customers included
18	OP+DR	Partial AMI: Zone 4 – Current tariff with opt-in to CPP-Pure tariff (residential and small C&I)
19	OP+DR	Partial AMI: Zone 4 – Current tariff with Opt-in to CPP-F residential/CPP-V small C&I
20	OP+DR+ REL	Partial AMI: Zone 4 – Current tariff with opt-in to CPP Pure
21	OP+DR+ REL	Partial AMI: Zone 4 – Current tariff with opt-in to CPP-F residential/CPP-V small C&I
22*	OP+DR+ REL	Omitted*
23*	OP+DR	Omitted*
Benefits: OP=Operational, OP+DR=Operational + Demand Response, OP+DR+REL= Operational + Demand Response + Reliability		

* We have not pursued these business case scenarios presented in our October 22, 2004 filing which contained SCE's alternate analysis beyond the requirements of the Ruling.

Our revised preliminary analysis of the required business case scenarios followed the Ruling's prescribed requirements to the fullest extent possible. Scenarios 1 through 8 are full AMI deployment scenarios and Scenarios 12 through 21 are partial deployment scenarios. Scenarios 12 and 13 focus only on large customers (greater than 200kW in demand) who are already equipped with advanced metering.

SCE performed a "bottoms up" analysis of the incremental costs and benefits in the categories delineated by the Ruling. To the extent possible, we estimated individual cost and benefit components in detail. Costs were "rolled up" into the major categories of: (1) Start-Up and Design Costs, (2) Installation Costs, and (3) O&M Costs for each scenario, as required. Total costs for each business case scenario were compiled by year and entered into our financial model along with any operational and demand response benefits. The exceptions to this "bottoms up" analysis are the two outsourcing scenarios (*i.e.*, Scenarios 2 and 14). We engaged an outside consultant to analyze these scenarios based on inputs from various integrated solutions providers with broad outsourcing experience in this area. The estimates provided by the service providers were conducted from a "top-down" perspective and they did not use the detailed costs and benefits categories used in the other scenarios.

Additional information about how we addressed our proposed residential air conditioning load control program in the AMI business case scenarios, how we performed the outsourcing scenario analyses and how we quantified risks and uncertainties are provided below.

1. Approach Concerning SCE's Existing and Proposed Load Control Program

Implementing the Ruling's analysis framework required certain adjustments to account for our existing Air Conditioning Cycling Program (ACCP) and our proposed residential Advanced Load Control (ALC) program. ALC is considered a Business As Usual case since it is in our long-term procurement plan and our 2005 plan for demand response program proposals filed on October 15, 2004 (R.02-06-001). ALC can be implemented independent of, or in tandem with, AMI. However, the Ruling specifies that the utilities are to model Operational-Only cases, a series of Demand Response cases that exclude Reliability, and finally a series of Demand Response Plus Reliability cases. We therefore considered ALC and other load control programs to be "out of scope" for the Operational-Only and Demand Response cases, and thus did not include any costs or benefits from such programs in those scenarios. This is not to imply that we would not propose to move forward with ALC under those business case scenarios. Rather, in light of the Ruling's required "building block" approach to the various scenarios, the joint implementation of ALC and AMI is considered in the Demand Response Plus Reliability scenarios.

For the Demand Response Plus Reliability cases, we added ALC where economically cost effective in the residential class. For small C&I customers we assumed that the existing ACCP and Smart Thermostat program would continue to provide the reliability component for that class. For the large customer class, we assumed that the Schedule I-6 interruptible program would continue and all other customers would be placed on RTP rates, (Scenario 13).

We did not analyze the combination of a single residential customer enrolled in both ALC and CPP rates nor did we examine the effect of a small C&I customer enrolled in the Smart Thermostat program combined with CPP-V rates.

There were two key reasons for this. First, the business case economics for the combination of a CPP rate and a load control program would be seriously degraded because most of the load reduction at peak times from CPP is due to a reduction in air conditioning use. That would essentially "steal away" the expected load reduction obtained from a load control program that uses thermostats or air conditioning switches. Although the response to a CPP rate could be enhanced by enabling technologies, the demand response benefit increment provided by the enabling equipment plus customer incentives required do not offset the marginal benefit. Alternatively, we assumed that all residential customers not on CPP rates would be eligible for the ALC program and in those scenarios, the net present value result is improved over the comparable demand response-only case. Second, the SPP experiment sample of customers with both CPP-V and Smart Thermostats (both residential and small commercial) were not representative and therefore the load reduction results are not applicable to broad application.[2]

We also assume that our partial business case scenarios involving residential deployment for Zone 4[3] are not materially affected by the ALC costs and benefits. We could implement the full ALC program under any of the partial scenarios. However, to remain consistent with the Rulings "building block" approach, we assume that we will fully deploy ALC in all zones under the Zone 4 partial AMI scenarios in the Demand Response Plus Reliability cases (Scenarios 20 and 21).

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2 Charles River Associates, Statewide Pricing Pilot Summer 2003 Impact Analysis, p. 103.
3 Zone 4 is one of the designated climate zones from the SPP representing very hot, desert areas.

2. Approach Concerning Outsourcing Scenarios

Our approach to the outsourcing Operational-Only scenarios is set forth in detail in Volumes 3 and 4.[4] Generally, this approach was to gather high level data through a modified Request for Information (RFI) process, with iterative steps for data gathering/clarification or refinement. This process was completed over approximately eight weeks. This process began with an evaluation of existing full service integrated solution providers that could potentially deliver the services that would be required in the outsourcing of AMI.

The integrated solution providers were asked to prepare a preliminary solution adequate to meet the requirements of the full deployment and partial deployment scenarios. Their solutions were to be reasonably consistent with available technologies, and executable under the specified parameters. They were to include a price estimate, including a financial (pricing) model delineating when (or how) the charges would actually be incurred.

A baseline was created of the current meter organizations Field Service Meter Reading Organization (FSMRO), Meter Service Organization (MSO), and Transmission and Distribution Business Unit (TDBU) using 2004 budget information and recorded costs through July 2004. This baseline was used to assess the in-scope labor component and to determine our retained functions. For the sake of expediency, the financial data provided by the integrated solution providers was normalized through a series of communications with each of the service providers. This process also identified retained costs for SCE that would be considered as part of the end-to-end AMI solution and used in the comparison.

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[4] *See* Volume 3, Section III-B and Volume 4, Section IV.B.

3. Approach Concerning Quantifying Risks and Uncertainties

The quantitative risks regarding costs for each scenario were assessed by developing range estimates for most likely high and low sensitivities for each cost and operational benefit category with estimates greater than $5 million. We then used these values in statistical analyses using Monte Carlo simulation to identify the confidence levels of our estimates and potential contingency values. In each of the business case scenarios, our original estimates had very low confidence levels. A ninety percent confidence level, or the chance of not overrunning the cost, is reasonable for this type of project. The results of this analysis suggest that we should include contingency values for this project. Accordingly, we have calculated contingency amounts at the ninety percent confidence level for each scenario, although the contingency is not yet included in Tables 1-1 and 1-2 or other cash flow analysis summaries. The results are found in Volumes 3 and 4.

We employed a Monte Carlo simulation analysis to our estimate of demand response benefits for selected scenarios as well. The results are presented in Volumes 3 and 4 by business case scenario.

B. Business As Usual Base Case Analysis

1. Overarching Approach

The Business As Usual case, as described in the Ruling, is expected to serve as the "base case," or reference point from which to compare the relative costs and benefits of the various 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 purposes of this preliminary 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 full and partial AMI deployment scenarios described in Volumes 3 and 4 respectively, the Business As Usual case is based on actual costs as recorded, and forecast in our 2006 General Rate Case (GRC) proceeding.[5] For the 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 sixteen years will likely change today's cost and benefit structure, to facilitate this preliminary analysis, our base case assumes that the current operating environment and cost and benefit structure will remain static over the sixteen-year study period.[6] 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. Similarly, the demand response scenarios with widespread enrollment in CPP rates would offset a portion of the anticipated costs and load reduction resulting from the ALC programs. These modifications are

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[5] *See* SCE's 2006 GRC Application (A.04-12-014) filed on December 21, 2004.

[6] 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 other deployment scenarios can be compared.

described in more detail in the scenario-by-scenario analysis set forth in Volumes 3 and 4.

Table 2-2 shows the recent history and our forecast of "business as usual" metering capital and O&M expenditures.

Table 2-2
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

2. Existing Advanced Metering and Communications Infrastructure

In the normal course of doing business, we are constantly assessing 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.

a) Real Time Energy Metering (RTEM)

We currently have approximately 13,000 RTEM installations which measure fifteen-minute interval usage data for customers with monthly demands of 200 kW and greater.[7] We also have approximately 700 RTEM units in place for our residential and small commercial customers who participated in the

[7] 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.

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 (ISO) 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.

b) <u>Automated Meter Reading</u>

As discussed in Volume 1, 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 150,000 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 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 the full-deployment scenarios, we have assumed that the entire AMR infrastructure is replaced by AMI. This replacement, on the 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.

c) <u>Advanced Load Control</u>

ALC systems can and do function effectively, independent of the proposed AMI infrastructure. This is the case with over 124,000 currently-active air conditioning load control 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.

Although load control devices can be a complement to AMI and dynamic pricing programs, enrollment in the ALC program would likely be affected under a full AMI deployment scenario with a default CPP tariff. Though the base case costs associated with the ALC programs proposed in the LTPP would be substantially reduced, up to eighty percent of the load reduction anticipated from expected direct load control programs would be usurped by an eighty percent adoption of CPP. We assume that our proposed ALC program will go forward in all Demand Response Plus Reliability scenarios, except that in the business case scenarios for full deployment that contain CPP participation, we adjust the ALC deployment to preclude simultaneous CPP and ALC enrollment. In those cases, we adjust ALC tariff enrollment to reach an eventual twenty-five percent market penetration of residential service accounts with air conditioning that are not on a CPP tariff.

d) 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, 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.[8] This 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

[8] *See* SCE's 2006 GRC Application (A.04-12-014) filed on December 21, 2004, Ex. No. SCE-3, Vol. 3, Part IV.

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 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% of customer calls into our phone center that are currently mapped through OMS.

Because we already have adequately functioning OMS, TLM, and SCADA systems,[9] we already obtain associated benefits in our T&D activities.[10] 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

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9 *Id.*

10 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.

costs or benefits of AMI relative to these systems in our full and partial deployment scenarios.

3. 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 associated with the partial and full AMI deployment scenarios 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.

a) IT Infrastructure Supporting Billing

Although much of the existing IT infrastructure that currently exists to support 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.

b) 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.[11] For the full deployment scenarios, the overall costs were reduced by $2.9 million (in 2004 PV dollars), to reflect this avoided cost of replacing these devices. For the partial deployment scenarios, the overall costs were reduced by $785,000 (in 2004 PV dollars).

c) 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 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 any of the full or partial scenarios as new costs. Material costs on the other hand will be significantly different for the various 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.

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[11] *See* SCE's GRC Application (A.04-012-014) submitted on December 21, 2004, Exhibit No. SCE-4, Vol. 2, Chapter V.

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.

III.

SCE'S KEY ASSUMPTIONS AND APPROACH FOR THE REVISED AMI BUSINESS CASE PRELIMINARY ANALYSIS

Results of the revised preliminary business case scenario analysis are driven by many key assumptions. Some assumptions were provided in the Ruling while additional assumptions had to be made to develop costs and benefits for our revised preliminary analysis. This section provides an overview of the overarching assumptions in the areas of AMI technology, demand response benefit approach and assumptions, economic perspective for analysis, and financial analysis and assumptions.

A. AMI Technology Selection Assumptions

In Attachment A to the 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 various scenarios is included in the revised preliminary business case analyses in Volumes 3 and 4.

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 principle 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 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 twenty-three 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 2-3 below:

Table 2-3 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 fifteen 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 eighteen vendors. Once the proposals were received, we used criteria identified in the RFI to evaluate the responses, as set forth below in Table 2-4. 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 eighteen 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 Ruling's required functional specifications.

Table 2-4
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) Standards	The ability of the AMI technology solution to reduce project complexity, costs, and risks.	20%

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.[12]

Our selected RF technology 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 ninety percent of our customers. It also appears to reduce project costs and complexity in comparison to other solutions.

Our selected 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

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[12] 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 18-24 months away from delivery for testing purposes.

real cost advantage. Based on our experience in attempting to retrofit existing meters for the AMR program, we learned that retrofitting adds 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 selected AMI technology solution 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.[13] 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 2-1.

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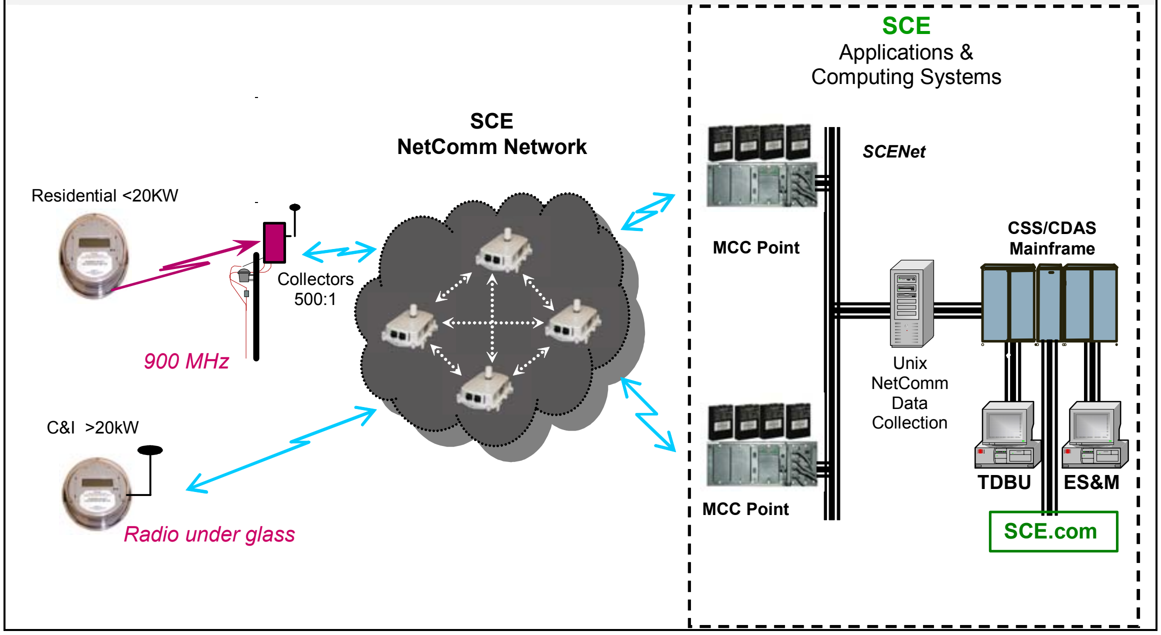
[13] Where a utility pole or streetlight is unavailable, such as in communities with extensive undergrounding of utility equipment, the collectors would have to be placed elsewhere, such as on an easement or leased site.

Figure 2-1
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[14] 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 4.

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

[14] Peer-to-peer involves data transmission from house to house or premise to premise.

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 (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 meter 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 forty-eight percent of the 16,000 meter population has been returned for warranty repair. Meter recalls due to design or material defects accounted for sixty-six percent of these failures. The remaining thirty-four 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 sixteen percent for our RTEM meters throughout this time period.

For the AMI revised preliminary business case analysis, 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 but not limited to the Customer Communications, Billing, FSMRO, and Electrical Metering Services organizations.

d) Staging and Development of Applications

The Ruling's required five-year meter deployment schedule is quite 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 ninety percent coverage.

2. Data Collection

Data collection requirements vary by customer type and will depend on the different business case scenario in question. For the purposes of the revised preliminary analysis, we are recommending fifteen-minute data collection for all customers above 20 kW and one hour data collection for all customers below 20 kW. This approach is consistent with Commission guidance in the Ruling. In an Operational-Only scenario for which there are no tariff requirements for more frequent polling, we would plan to collect aggregated, non-interval data much less frequently. In scenarios supporting demand response tariffs and the required provision of customer information, we plan to poll the meters daily for the energy consumed the previous day. As discussed throughout Volumes 3 and 4, the frequency of collecting data and the granularity of interval data that must be stored affects operational costs of various scenarios.

B. Demand Response Approach and Key Assumptions

In this section, we describe our approach and key assumptions for estimating demand response benefits from TDRs enabled by AMI. We attempted to follow the guidelines provided by the Ruling including framework for demand response scenarios, prescribed assumptions and demand response benefit categories. This section is divided into four subsections. First, we describe the key factors that drive the estimation of demand response benefits enabled by AMI. In the second subsection, we explain our approach to Monte Carlo analyses used to compute a range and expected value of results under a random simultaneous change of key assumptions for each demand response scenario. In the third section, we describe our approach to estimating the demand response benefit of placing large customers on a Real Time Pricing (RTP) rate. In the fourth section, we explain how our analysis addresses the four demand response benefit categories covered by the Ruling (DR-1 through DR-4).

1. **Key Factors and Assumptions in Estimating Demand Response Benefits**

Demand response benefits are driven by five key factors:

- TDR design and bill impacts;
- Customer adoption of dynamic rates;
- Customer response to dynamic rates;
- Load forecast adjustment to SPP load impacts; and
- The value of resources avoided.

Each of these factors is addressed in turn below.

a) **Rate Design and Bill Impact Assumptions**

Consistent with the Ruling, all rates (various CPP and TOU) used in the AMI business case scenarios for residential, small commercial, and medium commercial customers were designed to be revenue neutral to their respective otherwise applicable tariff (OAT). For each rate class, rates were designed with TOU periods being consistent with existing or experimental CPP rate structures). The design structures are summarized in Table 2-5 below and the process we used to analyze our proposed rate design and bill impact analysis is discussed in detail in Appendix C.

Table 2-5 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, customers are subjected to a fixed number of hours per daily CPP event (Residential: five hours, Commercial: six hours). Under CPP-V, customers are subjected to three hours per CPP event day. CPP-Pure (CPP-P) is designed as an overlay of existing rates, with the added revenue during CPP hours being offset by a percent reduction in the charges of the OAT. 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 adjustments in rates to account for this level of uncertainty would be difficult. Uncertainties of this type are more appropriately included as a de-rating factor associated with the value of the demand response.

CPP "adders" were constructed as the avoided $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 (6.1:1 in the case of non-AB1-X compliant CPP-F residential rates).

No customer cost differences that may occur due to this rate design were considered. For example, no additional meter costs or avoided meter reading costs were included. Estimated bill impacts were produced from our load research samples used in rate design not only to insure correct revenue neutral rate designs to class averages, but to assess the degree to which the customers might be impacted by these cost-based rates. Observing the level of bill impacts under a variety of customer response assumptions helps us to gauge customer acceptance of these rate designs. Other distinct advantages in using the rate design load research sample data include larger sample sizes and insurance against any participation bias as these accounts had their meters installed several years ago.

The results of our CPP-F rate design and bill impact analysis shows that without any load reduction during CPP events under the CPP-F scenario, the number of residential customers experiencing at least a ten percent annual bill increase is above twenty percent. Further, at the twenty percent load reduction level, about thirteen percent of residential customers still see bill increases of more than ten percent, while only about sixteen percent of our residential customers would see an annual bill decrease of at least ten percent.

Similar CPP-F bill impact analysis shows that for smaller GS-1 commercial customers, about twenty-two percent will experience annual bill increases of at least nine percent, while about twenty-six percent will experience a bill decrease of at least nine percent, assuming no load response. Assuming a twenty percent response, about thirty-one percent of GS-1 customers would see an annual bill reduction of at least nine percent, while fourteen percent would still see an annual increase of nine percent.

b) Approach to Estimating Customer Adoption of TDRs

Sustained customer adoption of TDRs is unknown since no utility has implemented such rates over a long period of time. For analysis purposes, we used sustained adoption rates required by the ruling for Opt-out (default tariff) enrollments of 80 percent. For the customers who opted-out of the default rate, we assumed that they chose an alternative rate in equal proportions. For example, in Scenario 3, we assumed that 80 percent of eligible customers default to a TOU rate and we assumed that 10 percent opt-into a CPP-F rate and 10 percent opt-into their current rate. In this filing, compared to our October 22, 2004 filing, we omitted optional scenarios 9, 10, 11, 22 and 23 where we assumed 50 percent adoption rates on an opt-out enrollment basis for TDRs as alternative analyses. The results of those cases were substantially unfavorable and, thus there was no need to pursue them again in this filing.

For opt-in enrollments, the Ruling did not provide assigned assumptions. We therefore relied on the Momentum Market Intelligence (MMI) customer adoption model to determine customer adoption rates. We assumed that those enrollment rates would be sustained over the full study period. For certain business case assumptions, SCE used the MMI simulation model developed in the SPP to predict initial customer enrollment on tariffs based upon customer awareness and potential bill savings. Although the model provided a point estimate, the margin for error in this approach is significant.[15]

For large customers (>200kW) we assumed that all customers are placed on an RTP rate on a mandatory basis. In Scenario 12, we assumed that all large customers are placed on a RTP rate. In Scenario 13, we assumed that

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[15] Momentum Market Intelligence, "Customer Preferences Market Research, A Market Assessment of Time-Differentiated Rates among Residential Customers in California," December 2003, p. 6.

customers currently on Schedule I-6 would stay on that program and all others are placed on a RTP rate.

Our assumptions by scenario are shown in Tables 2-6, 2-7 and 2-8 below.

Table 2-6
Residential Customer Tariff Adoption Rates by Business Case Scenario

Scenario	Default Tariff	Other Tariffs	Full or Partial Deploy-ment	TOU	CPP-F	CPP-V	CPP-P	Current	ALC
3	TOU	CPP-F or Current	Full	**80%**	10%	N/A	N/A	10%	
4	CPP-F/V	TOU or Current	Full	10%	**80%**		N/A	10%	
5	Current	CPP-P	Full				22%	78%	
6	Current	CPP-F	Full		11%*	8%*		81%*	
7	CPP-F/V	TOU or Current	Full	10%	**80%**			8%	2%
8	Current	CPP-P	Full				23%	69%	8%
9	Omitted								
10	Omitted								
11	Omitted								
16	TOU	CPP-F or Current	Partial	**80%**	10%			10%	
17	CPP-F	TOU or Current	Partial	10%	**80%**			10%	
18	Current	CPP-P	Partial				25%	75%	
19	Current	CPP-F	Partial		18%	6%		76%	
20	Current	CPP-P	Partial				25%	66%	9%
21	Current	CPP-F	Partial		18%	6%		67%	9%
22	Omitted								
23	Omitted								

The percentages in **bold** indicate assumptions required by the Ruling. Percentages are of the total of C&I customers meters. * Indicates calculated assumption using MMI model.

Table 2-7
GS-1 C&I Customer Tariff Adoption Rates by Business Case Scenario

Scenario	**Default Tariff**	**Other Tariffs**	**Full or Partial Deploy-ment**	**TOU**	**CPP-F**	**CPP-V**	**CPP-P**	**Current**
3	TOU	CPP-V or Current	Full	**80%**	10%			10%
4	CPP-V	TOU or Current	Full	10%		**80%**		10%
5	Current	CPP-P	Full				34%	66%
6	Current	CPP-V	Full		22%	12%		66%
7	CPP-V	TOU or Current	Full	10%		**80%**		10%
8	Current	CPP-P	Full				34%	66%
9	Omitted							
10	Omitted							
11	Omitted							
16	TOU	CPP-V or Current	Partial	**80%**	10%			10%
17	CPP-V	TOU or Current	Partial	10%		**80%**		10%
18	Current	CPP-P	Partial				31%	69%
19	Current	CPP-V	Partial		29%	9%		62%
20	Current	CPP-P	Partial				31%	69%
21	Current	CPP-V	Partial		29%	9%		62%
22	Omitted							
23	Omitted							

The percentages in **bold** indicate assumptions required by the Ruling. Percentages are of the total of C&I customers meters. * Indicates calculated assumption using MMI model.

Table 2-8 GS-2 C&I Customer Tariff Adoption Rates by Business Case Scenario								
Scenario	**Default Tariff**	**Other Tariffs**	**Full or Partial Deploy-ment**	**TOU**	**CPP-F**	**CPP-V**	**CPP-P**	**Current**
3	TOU	CPP-V or Current	Full	**80%**	10%			10%
4	CPP-V	TOU or Current	Full	10%		**80%**		10%
5	Current	CPP-P	Full				34%	66%
6	Current	CPP-V	Full		22%	12%		66%
7	CPP-V	TOU or Current	Full	10%		**80%**		10%
8	Current	CPP-P	Full				34%	66%
9	Omitted							
10	Omitted							
11	Omitted							
16	TOU	CPP-F or Current	Partial	**80%**	10%			10%
17	CPP-V	TOU or Current	Partial	10%		**80%**		10%
18	Current	CPP-P	Partial				31%	69%
19	Current	CPP-V	Partial		29%	9%		62%
20	Current	CPP-P	Partial				31%	69%
21	Current	CPP-V	Partial		29%	9%		62%
22	Omitted							
23	Omitted							

The percentages in **bold** indicate assumptions required by the Ruling. Percentages are of the total of C&I customers meters. * Indicates calculated assumption using MMI model.

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 unfamiliar with such rates.[16]

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[16] Customers are generally familiar with peak/off peak time-of-use rates in the communications industry. However, CPP rates differ in that only certain sporadic 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.

Second, more than forty percent of customers surveyed preferred a tiered or flat rate over a variety of time-differentiated rates.[17] While about thirty percent of customers' initial preference was a time-of-use rate, the initial preference for CPP rates was less than ten percent.[18] 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. Less than five percent of the customers initially contacted actually enrolled in the program, despite offering an incentive payment. 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.

The assumption that eighty percent of customers will indefinitely remain on CPP rates required by the Ruling has never been demonstrated and is highly unlikely given the research completed to date. No utility has tested residential customer adoption of CPP rates on a default (opt-out) enrollment basis. Even the CPP treatment group in the SPP had an attrition rate of four to six percent, despite the offering of financial incentives to continue to participate in 2004.[19] Moreover, sustained enrollment is not addressed in the MMI model and there is no experience elsewhere with residential CPP rates. Over time, customers who default onto a rate will become more aware of their options and will gravitate toward the one that is most beneficial. Market research shows that there is always inertia caused by perceived risk of a change in rates. One factor that could reduce inertia against change from a default rate is that on average,

[17] Flexo Hiner & Partners, Inc., Final Report, February 11, 2003.

[18] *Id.*

[19] Monthly Report on Statewide Pricing Pilot to California Public Utilities Commission and California Energy Commission, Exhibit B, January 15, 2004.

customers tend to move residences every five to seven years[20] and doing so would provide the customer an opportunity to reconsider his or her rate choices.

Only very few large SCE customers have signed up for the CPP tariff since it was offered in December 2003. The primary barriers to large customer participation are: 1) the effect on products or productivity; 2) the level of on-peak prices or non-performance penalties; 3) the amount of potential bill savings; and 4) the inability to reduce peak loads.[21]

On a voluntary affirmative opt-in enrollment basis, our market research shows that less than ten percent of residential customers would adopt a CPP rate.[22] Only nine percent preferred CPP rates and twenty-nine percent of customers preferred TOU rates in a SCE market research study.[23] The SPP market research found that the CPP-F pilot rate would yield an opt-in market share of ten percent of customers that had thirty percent awareness of their rate options, seventeen percent enrollment with fifty percent awareness, and thirty-four percent enrollment with one-hundred percent awareness.[24]

Because the market research indicates that the vast majority of customers do not want 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 evidence of what can happen when customers become dissatisfied with TDRs. When PSE provided quarterly report

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[20] Service turn off orders for SCE in 2003 were about 740,000 or one-sixth of the customer base indicating a one-in-six year customer move rate on average.

[21] WG2 Evaluation Update – Market Survey Results, Quantum Consulting, Inc. and Summit Blue Consulting Inc., July 13, 2004, p. 16.

[22] Customer Preference Market Research Core Product Discrete Choice Simulator Residential Version 2.3 (with extrapolations) and Customer Preference Market Research Core Product Discrete Choice Simulator for Business Version 1.4 prepared by MMI.

[23] Flexo Hiner & Partners, Inc., Final Report, February 11, 2003.

[24] Momentum Market Intelligence, "Customer Preferences Market Research, A Market Assessment of Time-Differentiated Rates Among Residential Customers in California," December 2003, p. 98.

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 very upset. This initially resulted in a public relations problem and ultimately in PSE's decision to cancel the program.[25]

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 AB1-X, as directed by Agency Staff in WG3.[26]

For Demand Response Plus Reliability cases, we assumed that customers on TOU rates would be eligible for ALC participation, but customers on CPP-F or CPP-Pure rates would not. For commercial customers adopting CPP-V, we did not include an additional load control option. We assumed that the current Smart-Thermostat program covered that option.

Business case scenarios with high CPP customer adoption include significant marketing and customer education costs to sustain customer enrollment levels over time and to enhance customer responsiveness. The marketing/customer education efforts are discussed in Volumes 3 and 4.

c) <u>Approach to Estimating Customer Response to TDRs</u>

Our approach to estimating the amount of customer response to TDRs is based on: (1) statistically significant results of the SPP for summer 2003,[27] (2) adjustment of the SPP-measured load impact to SCE's territory, and (3) differences in customer response behavior between the TDR enrollment approach in

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[25] 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.

[26] *See*, Volume 2, §IV.E, *infra.*

[27] Final SPP results for summer 2004 are not yet available. We will incorporate 2004 SPP results in our March 15, 2005 filing, if available.

the SPP and the required enrollment assumptions for the business cases. On the first point, we relied on certain the results from the SPP for summer 2003 recognizing the limitations of the study including statistical significance and the fact that not all TDRs in the business cases were tested in the SPP. On the second point, we used a method and analytical tool to apply the SPP results to SCE's territory. For the last point, we made demand response behavior adjustments for opt-out enrollment scenarios because the SPP experiment did not test customers placed on TDRs on a default basis. We describe this approach to each of these points further below.

(1) Use of SPP Results in the Business Case Scenarios

For summer 2003, the SPP examined the load impact of different TDRs by residential and small C&I classes on a statewide basis. Some of the results from the summer 2003 statistical analysis of elasticity (and therefore load impacts) were at a level of less than 95 percent statistical confidence and therefore deemed "statistically not significant." Also, only CPP-F and CPP-V rates were included in the experiment. The CPP-Pure rate structure was not. Where the SPP results for a specific tariff were inconclusive or not examined, we relied on reasonable proxies. The SPP consultant, Charles River Associates (CRA) determined statistically significant findings for residential customers' response to CPP-F and CPP-V rates and small C&I customers' response to the CPP-V rate with enabling technology. Only the CPP-F results were directly applicable to the business cases. For other tariffs we used the following proxies as described below:

a) TOU rates: SPP results were inconclusive for customers on TOU rates for Summer 2003. However, CPP-F customers had a TOU rate on non-CPP days and the observed customer behavior on these days, as represented by a price elasticity, was used as a proxy for residential customers' demand response. For C&I customers, the TOU price elasticity was assumed to be twenty-five percent of that for residential customers. This estimate is supported by CRA and the literature.

b) CPP-F for commercial customers: SPP results were inconclusive. As a proxy, we used a price elasticity for C&I that is twenty-five percent of the residential price elasticity found in the SPP. This estimate is supported by CRA and by current literature.

c) CPP-V for residential and commercial customers: CPP-V results in the SPP were for a select group of customers who also had enabling response technologies and were therefore not representative. SCE used price elasticity for CPP-F as a proxy for CPP-V. CRA supports this proxy assumption.

d) CPP-Pure for residential and commercial customers: This rate was not tested in the SPP. We used the price elasticity for CPP-F as a proxy. CRA supports this proxy assumption.

e) 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 single-part RTP. This approach is described below.

(2) Application of SPP Statewide Results to SCE Territory

There are two key components of estimating the demand response from TDRs: (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 each of these components is described below.

(a) Existing Energy Use

We estimated the existing average energy use by climate zone and rate period for residential, GS-1 and GS-2 customers from our load research data. Our average energy use assumptions are shown in Table 2-9 below.

Table 2-9
Existing Average Energy Use by Class and SCE Climate Zone

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 derived from statewide observations in the SPP. 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 largely based on the SPP analysis. The SPP elasticity data for all of California are found in Table 5 of the CRA August 9, 2004 report and are summarized in Table 2-10 for SCE climate zones.

Table 2-10 Summary Measures for Price Responsiveness for CPP-F Rates CES Model Specifications						
Climate Zone	**Elasticity of Substitution (Weekday Peak to Off-Peak Electricity Use)**			**Price Elasticity for Daily Weekday Electricity Use**		
	CPP Days	Non-CPP Days	All Week-Days	CPP Days	Non-CPP Days	All Week-Days
2	-.061	-.053	-.054	-.029	-.026	-.027
3	-.099	-.091	-.092	-.014	-.010	-.011
4	-.121	-.109	-.111	-.032	-.024	-.025

To determine price elasticities for SCE, we made adjustments based on the weather conditions (*see* Table 2-11) and the central air conditioning (CAC) saturations representative of SCE populations in our Climate Zones 2, 3, and 4 (*see* Table 2-12).

Table 2-11 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 2-12 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 a load reduction simulation tool, we derived load reductions for customers in our territory by making adjustments for air conditioning saturation and cooling degree hours. The impact estimates for residential CPP-F and TOU TDRs are shown in Table 2-13 below. We used the impact estimates on peak for CPP-F as the proxy for CPP-V and CPP-Pure.

Table 2-13 Impact Estimates for SCE Specific Residential Tariffs CES Model Specification					
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)**	-.12	-.01	-.02	-.02
	% Change	-17.92	-1.54	-3.23	-3.23
Zone 3	**Change (kWh/hr)**	-.40	-.06	-.07	-.07
	% Change	-24.82	-4.38	-5.28	-5.28
Zone 4	**Change (kWh/hr)**	-.45	-.09	-.10	-.10
	% Change	-26.00	-5.91	-6.60	-6.60

(3) Customer Behavior Adjustment for Opt-out Default Enrollment Scenarios

The SPP provided measurements of participant response to TDRs in the Summer 2003 Impact Analysis by CRA.[28] CRA measured the response of the customers that participated in the experiment. While the participants who chose enrollment in a TDR may have demographic characteristics and average energy usage that are generally representative of the statewide population, 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. Only about five percent of those customers initially contacted agreed to participate in the experiment. Because demographics and average energy usage alone do not determine customer behavior, we believe that it is inappropriate to assume that all customers who default onto a tariff through an opt-out enrollment would behave in the same way on average as customers who affirmatively opt-in to a tariff.

As such, we made a customer behavior adjustment to demand response for business case scenarios involving an Opt-out enrollment process. In an Opt-out enrollment scenario that assumes eighty percent of customers are on the TDR, a portion of them would have opted-in to the rate, if an affirmative response was required (as in the SPP experiment) and another portion of customers simply end up on the rate because of lack of information, lack of interest or inertia against taking affirmative action. For the purposes of the AMI business case revised preliminary analysis, we assumed that the CRA summer 2003 rate impact results are representative of affirmative/opt-in customer enrollments.

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[28] Statewide Pilot Project, Summer 2003 Impact Analysis, Charles River Associates, August 9, 2004.

We apply those results to the portion of customers in a business case scenario who are assumed to affirmatively opt-in to a TDR. (The CRA rate impact results were refined for SCE territory and customer-specific characteristics, which are described further below.) For the portion of customers assumed to default to the CPP rate, we used the same CRA rate impact results but adjusted the total impact for them because (1) a large portion of customers would be completely unaware of their rate and would therefore not respond at all to CPP events and (2) another large portion of customers who are assumed to default to the rate (but would not otherwise affirmatively opt in to the rate) would be on the default because of inertia or lack of interest. The response of this group of customers is unknown but likely to be much less than the portion of customers who would have affirmatively wanted the rate (*i.e.,* opted in).

As an example, Scenario 4 assumes that eighty percent of eligible residential customers enroll on the CPP-F rate on a default basis. Using the MMI model, we determined that only 16.8 percent of SCE's residential customers would affirmatively opt-in to the CPP rate. We call this group "willing participants" on the CPP-F rate. Thus, the remaining 63.2 percent (80-16.8) must be customers who would chose not to opt-out of the CPP-F rate due to inertia, perception of risk or are unaware or would not understand their rate options. In essence, the 63.2 percent group are, to some degree, "unwilling participants" in the CPP-F rate. The load impact from the "unwilling participants" was not tested in the SPP or any other experiment and is unknown. However, it is reasonable to assume that some portion of that group would respond in a similar way to the opt-in group on average (the CRA analysis includes customers who respond and do not respond), some will respond less than the opt-in group on average and those who are completely unaware of their rate and the choices available to them will not respond at all. The MMI work in the SPP project demonstrates that an eighty percent enrollment is reached at only a fifty percent level of customer awareness. Thus, to be consistent with the eighty percent default assumption of opt-out enrollment it is fair to assume that half of the customers are unaware of their rate and are not likely to respond to it.

In this example, we assume that the load impact results from the SPP experiment can be factored into the estimate of SCE customers who default on a CPP-F rate. If all customers that default onto the CPP-F rate were to reduce load in the same way as the SPP participants, the load impact would be a full 100 percent of the SPP load reduction. As we just described above, that is not likely to be the case. For those who would have otherwise opted-in to the rate (willing participants) we assume 100 percent of the SPP load impact for the CPP-F rate. For the portion of customers who essentially default to the rate (unwilling participants) we assume only fifty percent of the load impact from the SPP experiment for CPP-F. Thus, on a weighted basis, we apply a 60.5% factor to the full SPP load impact for CPP-F for the entire population assumed to be on the CPP-F rate in Scenario 4, as shown in the table below:

Table 2-14
Load Impact Adjustment for Scenario 4 Using SPP Results for Summer 2003

	Percent of Eligible Customers Enrolled of Total Population	Percent of Customers on CPP-F	Factor of SPP Load Impact	Weighted Factor of SPP Load Impact Applied to CPP Customers
Willing (Opt-in) Participants	16.8	21	100 %	0.21
Unwilling Participants	63.2	79	50 %	0.395
Total	80	100		0.605

Therefore, as shown in Table 2-14 above, the adjusted the SPP load impacts for summer 2003 on a per customer basis by a factor of 0.605 (or 60.5

percent). We applied the approach in the above example to each of the opt-out enrollment business scenarios.

d) <u>Load Forecast Adjustment to SPP Load Impacts</u>

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. An additional statistical analysis is required to determine what load impact result from the SPP for SCE customers can be reasonably relied upon in the same way that we can rely on a combustion turbine (CT) operating.

The approximate forced outage rate of a CT is about five percent. As shown in Table 2-15, to treat the load response consistently, we used the lower end of the one-sided ninety-five percent confidence interval peak kW reduction to determine capacity savings. This is the value that will be available with ninety-five percent certainty when called upon, taking into account statistical modeling variability.

The results of our Monte Carlo analysis for each zone are shown in the table below. Our methodology for this computation is explained in Appendix D.

Table 2-15
Peak Load Impact at 95th Percentile

Zone	PRISM Peak kW Impact	95th Percentile Peak kW Impact
2	-.1201	-.1046
3	-.4046	-.3581
4	-.4498	-.3699

To reiterate, the analysis described here quantifies the uncertainty due to model estimation. The distribution indicates the variability that we can expect to see in the load impact resulting from model uncertainty. There are other factors with uncertainty that impact the value of the peak reduction, but they are dealt with in a separate analysis that looks at the resource availability (the number of times an event can be called, the likelihood of calling an event on the "right" day, *etc.*) in the Avoided Resource Values subsection below. In addition, using both one-in-ten and one-in-two weather scenarios would capture some of the variability due to weather uncertainty.

To calculate energy savings, we used the entire distribution of the load impact estimate, as developed using the Monte Carlo simulation. This is appropriate because energy is expected to be more variable, while the capacity value needs more certainty.

With this adjustment the estimated load impact is more suitable as a modifier to our peak load forecast. In other words, the adjusted load impact is what is "countable" towards a peak load reduction. This quantity is what was used to determine the DR-1 avoided capacity benefit and DR-2, the avoided reserve requirement.

e) <u>**Avoided Resource Values**</u>

For all the required scenarios, the 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 Ruling. However, we do not believe that $85/kW-yr is the correct value to use in this business case and we performed an alternative analysis in a Monte Carlo simulation study of Scenario 4, as described in the subsection below. For our March 15, 2005 application, we intend to fully analyze the value of demand reductions from TDR tariffs to account for differences between this resource that has serious limitations compared to a combustion turbine, which is available all year at a highly predictable level of reliability.

2. Approach to Monte Carlo Analysis of Demand Response Benefits

For illustrative purposes, we applied a Monte Carlo simulation approach to the demand response benefit calculation for Scenario 4. Scenario 4 is where we assume that eighty percent of customers default onto the CPP-F rate. Recall that we assume that for opt-out enrollment scenarios, we distinguish customer response between "willing participants" and "unwilling" participants on the default rate. For the Monte Carlo analysis, we varied the customer behavior characteristic of unwilling participants from a mean of fifty percent of the load impact of the SPP experiment to thirty-three percent on the low side and sixty-seven percent on the high side.

In addition, we applied a derated value to capacity resources to account for differences between TDRs as a resource and a combustion turbine. The deferral cost of a combustion-turbine traditionally has been used as a proxy for the value of peaking capacity. Combustion turbines provide capacity when called to a certainty value equal to their availability rate (1 – expected force outage rate). Time differentiated rate programs (TDRs) such as CPP may have operational constraints that may reduce their capacity value relative to combustion turbines. The operational constraints of CPP may include limitations on the number of calls per year, time restrictions on when a program can be called, limitations on hours per day and lead times to execution. For this Monte Carlo study, we assumed a distribution between fifty percent and ninety percent of the full combustion turbine value to account for the operational constraints of the TDRs. This range is based on our estimates of the distribution pattern of limited energy programs and these values may change as we continue to review this methodology.

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 2-16 below.

Table 2-16
Results of Alternative Analysis of DR-1 Benefits for Scenario 4

Assumptions	Result in Present Value ($2004)
Demand Response Benefit Assuming Commission Staff Assumptions	300.8
Alternative Analysis Monte Carlo Low	184.0
Alternative Analysis Monte Carlo Mean	205.2
Alternative Analysis Monte Carlo High	229.0

As shown above, our alternative analysis is that the demand response benefit using Commission Staff assumptions for Avoided Resource Value are overstated by almost one-third. A more reasonable result for the DR-1 benefit for Scenario 4 is the Monte Carlo Mean of $205.2 million in present value. Since DR-2 benefits and losses are a function of the DR-1 benefit, the total demand response benefit for Scenario 4 is overstated using the Ruling's avoided costs assumptions by about one-third.

3. Real Time Pricing (RTP) for Large C&I Customers (>200 kW Customers)

Our basic approach to estimating large customers' response to an RTP rate was to start with the results of the study that Christensen Associates performed for the California Energy Commission (CEC)[29] to estimate the statewide savings due to the potential implementation of RTP across the three major California investor-owned utilities. We applied those results, by Standard Industrial Classification (SIC) code, to the population of SCE customers with peak demands over 200 kW.

We also considered two scenarios, one in which all customers over 200 kW were moved to an RTP tariff, and one in which those customers currently served on an interruptible rate (Schedule I-6) remained on the interruptible rate, and those served on any of the firm service rate schedules were moved to an RTP tariff.

Using the results of the Christensen report, we were able to make a preliminary estimate of the MW savings at system peak from firm and interruptible customer groups. The estimates are shown in Table 2-17 below. The process we employed to arrive at these preliminary estimates is described more completely in Appendix A of this volume.

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[29] Potential Impact of Real-Time Pricing in California, by Steve Braithwait and David Armstrong (Christensen Associates), January 14, 2004.

Table 2-17 Estimated Demand Reductions from RTP Tariff for Customers with Demand >200 kW			
Group	**Total Group Contribution to System Peak**	**Estimated Savings at System Peak**	**Percent Savings**
Firm	4,318.5 MW	185.4 MW	4.3%
Interruptible	795.2 MW	175.9 MW	22.1%
Total	5,113.7 MW	361.3 MW	7.1%

These estimates reflect the mix of SCE customers over 200 kW and the price response from the Christensen analysis done using real-world experience of the Georgia Power RTP program. They do not reflect the actual load shapes of these particular SCE customers, or the prices that SCE customers paid during September 2003, when the system peak load data were collected. However, by using the same responses and load shapes that were used by Christensen, the results of our analysis are consistent with the statewide estimates from the Christensen analysis.

4. Demand Response Benefit Categories Approach and Assumptions

The 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. Our approach and assumptions for each Demand Response benefit category is described in the subsections that follow.

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.

As described above, 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 Ruling and adjusted avoided resource values for the capacity component of avoided procurement costs.

For the energy portion of avoided energy, we used $70/MWh ($63/MWh for peak energy plus $7/MWh for congestion) for the energy savings. We also varied the value of energy savings in the Monte Carlo analyses.

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.[30]

b) <u>DR-2: System Reliability Benefits (Capacity Buffer)</u>

We agree that for load reductions from "reliable" load response to TDRs, reserve requirements are avoided. We define "reliable" load response as the response computed at a ninety-five percent confidence interval. In applicable scenarios, we also apply a system reliability benefit of fifteen percent reserves to the "reliable" load response. We calculate a value for this benefit at the avoided capacity cost defined by the Ruling ($85/kW-year) for inclusion in the required business case scenarios.

c) <u>DR-3: Dynamic Fuel Switching/Dynamic Integration of Conventional and Distributed Supplies</u>

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

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[30] This is for losses between the end use meter and the generator. Average annual distribution loss factors in the 5% range.

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 reliable and durable load reductions to avoid transmission and distribution upgrades. We describe transmission upgrade issues separate from 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. 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, system reliability could be immediately threatened. SCE does not believe that demand reductions from TDRs can be counted on in transmission planning until there are many years of experience.

With respect to distribution additions/upgrades, we believe that there again are no quantifiable benefits from TDRs for the same reasons discussed above. 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. 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." 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.

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.

C. <u>Proper Economic Perspective For Analysis</u>

We are using the all-ratepayer or societal perspective for this revised preliminary analysis. The costs are the investment and operational costs of implementing AMI. The benefits are the operational savings and demand response benefits (*i.e.*, resource cost savings). We also believe that demand response benefits should be reduced by the value of service loss to customers and we include this analysis as an alternative to our business case results for consideration by the Commission. The implications of value of service loss on the analysis have not been extensively discussed in workshops leading up to this filing. However, value of service impacts are an essential element of a proper analysis.

If customers are forced to curtail usage to avoid higher bills, they essentially face a decline in service for the same money or incur a loss in the value of service previously provided. While usage curtailment at peak would reduce the utility's production costs, customers may be worse off to the extent that they experience less comfort or have to change usage habits. This value of service loss should be taken into account as a societal cost that offsets societal benefits of reduced production costs. This is discussed below in detail.

The traditional method the Commission has used to evaluate utility demand-side management programs is the Demand Side Management Standard Practice Manual (SPM).[31] The SPM recommends presenting results from a variety of perspectives, including those of the program participants, other ratepayers (non-participants), and all ratepayers or society. The all-ratepayer or societal perspective is a measure of overall economic efficiency, while 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.

Programs involving dynamic pricing demand response options, such as those enabled by AMI technologies, cannot be directly evaluated using the SPM equations, however, because these equations omit the impact of price-induced

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[31] California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects, Interagency Green Accounting Working Group, October 12, 2001.

changes on customer usage behavior.[32] Changes in customer usage affect the value or benefit that a customer obtains from using electricity, and this needs to be taken into consideration in program evaluation. For example, an attic insulation program allows a customer to use less electricity while maintaining the same house temperature, so there is no effect on customer value. In contrast, a dynamic pricing program which raises prices on hot summer afternoons achieves lower usage by inducing the customer to increase the thermostat setting and thus forego some level of comfort. This loss of comfort (*i.e.*, maintaining the home at a higher temperature than the customer otherwise would) has some lost value associated with it. Introducing an additional term in the SPM equations to reflect this value of service loss is thus necessary to properly value pricing demand response programs.

As set forth in Appendix B to this volume, we have developed a mechanism for determining a value for the loss of service and we have applied it to many of the business case scenarios. The approach found that the benefit of demand response declines significantly. Thus, it is imperative that in the Commission's review of the cost effectiveness of AMI and of demand response programs, the full costs, such as the loss of value from service, are included. The SPM formulas, with the inclusion of a value of service loss element, yield an appropriate measure of the economic efficiency gain from introduction of price-based demand response programs. In contrast, using just resource cost savings as a criterion does not produce appropriate results.[33]

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[32] Although the equations contained in the SPM do not reflect value of service impacts, there is some indication that the authors intended such impacts to be considered: "However, attempts should be made to quantify indirect costs customers may incur that enable them to take advantage of TOU rates and similar programs. If no customer hardware costs are expected or estimates of indirect costs and value of service are unavailable, it may not be possible to calculate the benefit-cost ratio and discounted payback period." *Id.*, p. 17

[33] *See* Acton and Bridger, *op. cit.*, p. 23 ("Despite the widespread agreement among economists that the welfare measures constitute a correct measure of the impacts on well being, the criteria are frequently ignored in evaluating rate changes" and ". . . both the fuel savings criteria and the

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D. Financial Assumptions

Our key financial assumptions to develop the cost and benefit information used in the revised preliminary business case analysis are discussed below.

1. 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 various scenarios, while some positions will be reduced solely through attrition. In some scenarios, 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.

2. 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

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fuel plus capital savings criterion are wrong in principal, and in general, will lead to substantially incorrect measures of benefits").

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.[34] 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.[35]

3. Taxes

For cash flow purposes, we used tax rates of thirty-five percent for federal and 8.84% for state. Tax benefits from early write-off of the removed meters are included in the cash flow and revenue requirement analysis.

4. Cost of External Financing

The Ruling requires the utilities to evaluate various financing options for the large capital expenditure anticipated for a full deployment of AMI. Specifically, the 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.[36]

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 fifteen years for meter

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[34] *See* Volume 2, Section IV.3, Risk Assessment

[35] Unrecovered capital costs in 2021 were estimated to be approximately $19 million and $190 million respectfully for the partial (Zone 4) and full deployment scenarios.

[36] *See* Ruling, Attachment A, pp. 4, 8.

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 will be discussed in those outsourcing business case scenarios, none of the potential AMI outsource providers demonstrated the ability to provide superior financing terms above our own notwithstanding the capital lease issue.

5. Net Present Value Analysis and Assumptions

As detailed in Volumes 3 and 4, 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% 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 Ruling.

In this revised preliminary analysis, 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,[37] 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

[37] Higher O&M costs and depreciation would provide a tax deduction, while demand response benefits and O&M savings produced higher taxes.

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.

6. 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 each of the seventeen scenarios included in our revised preliminary analysis[38] for years 2006 through 2021. These estimates, which are detailed in Volumes 3 and 4, 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 the full deployment, that the total project revenue

[38] *See* Table 1 of Section II – General Approach for Scenario Definitions

requirement PV ranges from $831 million for Scenario 7 to $1.09 billion for Scenario 3. For a partial deployment, we estimate that the total project revenue requirement ranges from $(237) million for Scenario 12 to $236 million for Scenario 16. Results are discussed in detail in Volumes 3 and 4. Revenue requirement impacts were assessed for analysis purposes only.

7. Treatment of Costs not Clearly Anticipated by the Ruling

a) Pre-2006 Start-up Costs

The Ruling mandates a "2006 to 2021 analysis period,"[39] 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.

b) Early Retirement of Meters

To implement AMI, all existing meters that do not meet the communication and interval data capabilities required by the 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 the Full Deployment scenarios. 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 $380 million for the Full Deployment scenarios. 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

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[39] Ruling, Attachment A, p. 12.

contemporaneously with the system installation through an appropriate cost recovery mechanism.

IV.

RISK ASSESSMENT

Any endeavor of the magnitude envisioned here will inevitably carry with it significant uncertainties and risks. The Ruling requires the applicants to evaluate and address the key risks of AMI deployment both quantitatively and qualitatively. The extent of variation in business case scenarios addresses certain quantitative risks by assigning values to assumptions that vary widely. Monte Carlo analysis also quantifies risks.

Qualitative, or difficult-to-quantify, risks are by nature more problematic and can be addressed as a whole by setting a high financial hurdle rate or high positive NPV threshold. We have not used an abnormally high financial hurdle rate in our analyses. This section is a qualitative discussion of key risk areas and what steps could be taken to reduce uncertainties. The Commission may be able to address certain risks directly.

As described in Volume 1, SCE supports new technology and innovation when risks can be reasonably addressed and resolved. While there are myriad risks of varying magnitudes, we focus here only on the key risk areas that must be resolved before AMI can reasonably move forward. These areas include:

- AMI technology availability, maturity and reliability;
- Scale and scope of simultaneous AMI deployment;
- Longevity of AMI compared to other resource options;
- The uncertainty of true gains in economic efficiency;
- The existence of statutory restrictions against default price responsive rates; and
- The reliability of demand response at anticipated levels.

Each of these risk areas and what is necessary to reduce or resolve them is described below.

A. The Uncertainty Concerning the Reliability of AMI Technology Must Be Resolved for AMI to Be Successful

As noted above, we are not aware of any deployments of AMI in the United States at the scale and functionality envisioned by the Ruling. While some utilities, such as Xcel Energy, Ameren and Exelon, have deployed interval data meters communicating with a fixed network, these utilities are only collecting monthly meter read data and have not yet implemented an end-to-end integrated system that can collect and process 15-minute and hourly data and bill customers on a large-scale. As such, there are a number of technological uncertainties and risks associated with a full deployment of AMI that must be resolved before an AMI deployment could be successful.

Although interval metering has been available for some time and is a fairly proven technology with which California and other utilities have experience, the communications aspect of the AMI network is more unpredictable. Because the two-way RF communications aspect of AMI is a fairly recent innovation and thus, is largely untested in real installations, there is risk of unexpected and unpredictable delays and problems. These problems will become magnified, given the size of a full scale deployment and the speed of the Ruling's contemplated roll-out period.[40] In addition, due to the sheer size

[40] In SCE's deployment of RTEMs to customers with demand of 200 kW or greater, many of the defects and ensuing delays were caused by communications problems. For example, from 2001 through 2004, we have purchased 16,158 remotely communicating interval meters for the initial RTEM deployment and for the SPP, during which 7,774 (or roughly 48%) meters were returned for warranty repair (66% due to meter recalls and 34% resulting from workmanship related or material defects). The majority of trouble reports, approximately 54%, were related to communication issues, including failures in the communications modules, wireless coverage, wired phone lines, or the meter itself. These meter defects and

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and geographic diversity of SCE's service territory, there is a chance that there may be less-than-expected coverage, which could require additional collectors and other hardware than estimated, which adds additional risk of delay and cost overruns. Moreover, some components of the infrastructure are still being developed and integrated with existing AMI network technology, so there are substantial risks that the communication hardware may not interface properly with these yet-to-be designed in-home displays (*e.g.*, for CPP notification) or load control devices.

Because of the communication aspect of the technology, if there is a technical problem resulting in a communication failure, there is the increased risk of lost data which would then require an estimated bill, therefore increasing ongoing operating costs. The complexity of collecting, validating, billing, and storing the large volume of interval data vastly increases the magnitude of work and costs involved compared to once-monthly meter reads. This increased amount of data also increases the potential for data voids and the need for billing exceptions, which would contribute to increased ongoing operations and maintenance costs.

In addition to the risks associated with a newer technology, there is also the potential for technological obsolescence. For example, we have determined that based on today's costs and the Ruling's prescribed system requirements, the most cost-effective technological solution for AMI would be a RF hybrid mesh network. However, in a few years, one of the developing technologies, such as a power line carrier, may prove to be more reliable and cost effective, depending on technological advances and economies of scale. If eventually this or another

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recalls twice forced the RTEM deployment to stop altogether until the meter quality issues could be resolved, causing substantial delay in the deployment schedule of these 12,000 meters.

technology proves to be a superior and lower-cost alternative to today's RF solution, there is the risk that today's investment will become stranded.

Given the attention AMI is receiving around the world and given how quickly the marketplace can adapt to technological innovations (*e.g.*, advances in computers, cellular phones, television technology, *etc*.), the possibility that there is a better, faster, cheaper and more reliable technology right around the corner is very real. As such, an additional technological risk is investing in a nascent technology too soon or at too high a cost. The metering and communications equipment vendors must demonstrate that AMI technology with the functionality specified in the Ruling is commercially available and proven before any decision on AMI deployment can be made. The Commission should exercise due care before ordering a deployment of emerging rather than proven technologies.

As described above, there are several technology 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 technologies are compatible. As such, a failure for 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 a significant negative financial and schedule impact.

Another considerable risk is the availability of integrated ALC functionality within the LAN/WAN/Metering architecture. Most AMI technology solutions, including that selected by SCE as the technology of choice (given the Ruling's aggressive near-term hypothetical deployment), do not yet possess commercially available hardware with related embedded ALC functionality. Although most of the vendors providing responses to our RFI proposal 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 without providing any details whatsoever, there are inherent risks associated with near-term true commercial availability.

For AMI to be successful, the substantial uncertainty about the reliability and cost of the technology currently available must be resolved.

B. The Uncertainty Concerning the Feasibility of a Simultaneous Statewide Deployment Must Be Resolved for AMI to Be Successful

In a general sense, the full, simultaneous statewide deployment of the scale and scope envisioned in the Ruling would be a first-of-a-kind endeavor with associated uncertainties and risks. We are not aware of any other previous AMI deployment anywhere in the country of the size, scope, or complexity envisioned by the Ruling. We understand that in several states, utilities have undertaken fairly large AMR programs with a significant installation of electronically-read meters (similar to the more than 500,000 meters we currently read as part of our AMR program), but that these deployments are simple AMR programs (for which usage data is cumulative and the meters are read once per month), not AMI with interval meters and demand response (for which the usage data is divided into hourly or smaller intervals and collected at least daily with the capability of next-day customer access). In addition, we are aware of several projects around the country deploying certain demand response programs to residential customers, but certainly not on the scale and within the parameters and functionality of the required business case.[41]

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[41] In SCE's attempt to research other utilities' experience with AMR and price responsive rates, SCE was unable to find another utility that had deployed AMI to the scale and scope envisioned by the Ruling, and was collecting and billing on interval metering data. Although PPL Electric Utilities has deployed advanced meters to roughly 1 million customers, we

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A significant risk of full-scale deployment is the possibility that all three respondent utilities would simultaneously undertake their own mass deployments in their respective service territories. On a statewide basis, this deployment would encompass replacing more than 15 million electric and gas meters within the five-year deployment window, which would have definite impacts on the utilities' ability to manage a handful of vendors and compete for a limited supply of materials and skilled labor force. We are not aware of any other AMI or AMR deployment in the United States even close to this magnitude that involves the same level of complexity in system functionality and operational requirements, and thus, we question whether the vendors are or will have time to become prepared for a mass deployment starting in 2006.[42]

Specifically, simultaneous statewide full deployment by the utilities would likely stress the metering equipment vendors' ability to deliver materials on time and to handle component failures quickly. During the deployment of approximately 12,000 RTEMs during the energy crisis, we experienced a number of delays in obtaining a sufficient supply of meters to keep pace with the installation schedule and several significant delays in getting numerous technical defects corrected.[43] On a statewide basis, the five-year deployment window will require the installation of more than 12,000 meters per day.[44] Any

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understand that only a small fraction of those customers are on a price-responsive rate. Likewise, although Puget Sound Energy placed roughly 270,000 customers on a TOU rate before the program was discontinued, this program did not involve the collection, billing and storage of interval data or the complex communications infrastructure required by the Ruling.

42 The only meter deployment that is in this range is for the Italian Utility Enel where 30 million meters are being installed. This national program involved a unique meter design.

43 Our 12,000 RTEM installations were anticipated to take one year, but the actual installation period due to these meter availability problems and product defects causing meter recalls was stretched to two years.

44 Based on roughly 15 million gas and electric meters statewide, assuming a five-year deployment and a five-day work week.

delay in meter availability or quality control problems will quickly create an enormous backlog and hinder such a deployment.

The aggressive five-year full-scale deployment window also poses several challenges which could be multiplied on a statewide basis. Ideally, the installation of the communications network should precede the installation of meters so that the communications link can be verified at the time the meter is installed. To roll out the required volume of meters within the prescribed time-frame, however, meter installations will need to commence prior to the completion of the communications network and back office system interfaces. As such, when these initial meters are installed, there is no way to know until the network is operational whether the meters can communicate properly or whether additional communications hardware will be required. As a result, there will be the need for additional return visits to investigate and repair communications failures.

Given this substantial uncertainty concerning the feasibility of a simultaneous statewide deployment, it may not be prudent for California to undertake a simultaneous statewide installation because if there are problems, they would likely occur threefold. One way to mitigate these risks would be to do a staged deployment, with one utility deploying first and the other utilities deploying with the benefit of the lessons learned and experience gained from that first deployment. A simultaneous statewide deployment essentially puts "all of the eggs in one basket" by imposing the risks of AMI deployment across the entire state, instead of taking a more cautious phased-in approach, which would reduce these risks and uncertainties before full scale statewide deployment.

C. The Uncertainty of the Longevity of the AMI System Compared to Other Resource Options Must Be Considered

In moving to an AMI system, meters will have solid state technology, which is a newer technology with sensitive electronic components. The generally-accepted lifespan for solid state meters and meters with electronic components is fifteen years, compared to the industry-average lifespan of thirty years for mechanical meters (*i.e.*, those currently in use today for the majority of residential customers). This shorter lifespan of the AMI meters will require more frequent replacement of meters and network components than we currently experience.

Assuming a 2006 start date for AMI systems installation, this fifteen-year lifespan of solid state meters would mean that we would have to begin replacing meters in mass no later than 2021, which is the end of the Ruling's business case analysis period of 2006 through 2021. These start-up and installation activities would include materials procurement and the hiring and training of supplemental installation staff, plus likely installation of some actual meters, depending on the roll-out plan developed at that time.[45]

In addition, having gone down the path of AMI, there are other non-metering hardware aspects of the infrastructure, such as communication network or IT hardware that would also need to be refreshed throughout the

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[45] Given the estimated failure rate of the meters under a full scale meter deployment, a certain number of meters (estimated to be roughly 31%) will likely have already been replaced well before the fifteen-year lifespan has expired, and thus, SCE anticipates that it would only need to replace those remaining meters nearing the end of their anticipated fifteen-year life and continue this process over time. Depending on the number of failed meters actually replaced, it is possible that SCE could design its second AMI deployment plan accordingly either to (i) proactively replace 100% of the meters including meters that might only be a few years old, or (ii) replace the meters in piecemeal fashion as they actually fail, recognizing the possibility of extremely high number of failures within a shorter duration and the associated customer and billing impacts.

Ruling's sixteen-year analysis period (2006-2021) in order to maintain the AMI system. Some non-metering hardware components, such as our field data collection infrastructure,[46] also have a fifteen-year lifespan and would have to be refreshed in 2021 in order to be capable of continuing to support AMI. Other hardware components necessary for AMI, including servers and related software, have a five-year refresh cycle, and assuming installation beginning in 2006, will have a necessary refresh cost in 2011 and 2016. These hardware components would also necessarily have to be refreshed in 2021 after the next five-year refresh cycle in order to continue to support AMI going past the Ruling's analysis period.

These significant replacement costs for metering and non-metering hardware that will necessarily be incurred in 2021 have *not* been included in the current analysis even though they will be incurred during the Ruling's required analysis period (2006-2021). The estimates regarding the possible costs for these anticipated activities are highly uncertain, given that they are more than fifteen years away, and technological advances might result in deploying a different technology that is not available or cost effective today. Some costs are expected to increase over time, such as labor, but others could possibly decrease, such as the cost of technology. Thus, it is too uncertain to even begin to project the cost implications of the second wave of AMI installations beginning in 2021 with any precision. Moreover, because we are not counting the potential benefits to be derived from the future wave of AMI deployments in this analysis, we decided it is most comparable to leave these refresh costs out of the analysis, despite the fact that dealing with the post-2021 bubble of meter and related hardware replacements will cause very significant costs during the 2006-2021 business

[46] *See* Section 3(a) AMI Technology Assumptions

case analysis period. Thus, the shorter estimated lifespan of AMI meters and other hardware creates significant uncertainty regarding the true costs of AMI compared to other resources that have a longer lifespan and more predictable maintenance record. For AMI to be successful and to be a cost-effective resource among other resource options, these uncertainties must be resolved so that the full costs of AMI can be compared to other resources.

D. <u>The Uncertainty of Economic Efficiency Gains and Societal Benefits Should Be Considered</u>

Although TDRs may induce certain customer behaviors producing demand reductions, it is difficult to assess whether such behaviors directly translate to economic or societal gains. As noted in Volume 1, one of the fundamental requirements for AMI to be successful is that dynamic pricing tariffs must approximate actual market prices, rather than be designed solely to elicit demand response. 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.

Second, 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. Generally, economists want prices to be "just right" for maximum economic efficiency. This is a noble, but elusive goal in regulatory ratemaking. Only real-time retail prices that track wholesale prices in a functioning wholesale market will accomplish that goal. Rates such as CPP, TOU or tiered rates structured to track market prices must necessarily be designed to recover a utility's overall revenue requirement. This "second best" adjustment may interfere with the efficiency of these rates. In addition, there is no readily available source for market prices today. The ISO maintains a real-time market today, but there are significant questions about whether this would provide an appropriate measure due to the small volume traded, the influence of large quantities of bilateral contract obligations (principally the California Department of Water Resources (CDWR) contracts), and ongoing ISO market-redesign efforts to incorporate capacity and locational pricing.

Third, the actual avoided costs of generation from demand response will change depending on the market. Recently, the Commission has ordered load serving entities to maintain a fifteen percent reserve requirement to ensure resource adequacy. This requirement will force SCE to have sufficient capacity to meet 115 percent of its peak demand, which is intended to alleviate energy and capacity shortages. We anticipate that as a result of these resource adequacy requirements, the overall market will stabilize, therefore producing less variation in prices between peak and off-peak periods and reducing the frequency and effect of CPP days. With this market stabilization, we would expect the marginal costs of energy to also stabilize, thereby reducing the differential between on-peak and off-peak rates. Reducing the differential would also reduce expected price-induced demand response.

E. The Uncertainty of the Existence of Statutory Restrictions Against Price-Responsive Rates Must Be Resolved for AMI to Be Successful

The Ruling requires the utilities to analyze several different tariff structures in an effort to determine the costs and benefits associated with the deployment of AMI.[47] The Ruling recognizes, however, that in the near term, legislative constraints on rate design modifications may have a considerable

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[47] Ruling, Attachment A, pp. 4-5, 10.

impact on the benefits derived from the full scale deployment of AMI.[48] The legislative constraint alluded to in the Ruling is the result of Section 80110 of the California Water Code enacted by AB1-X as a result of the 2000-2001 energy crisis. Section 80110 prohibits the Commission from increasing any electricity charges for residential customers' usage of up to 130 percent of their existing baseline allowances. This prohibition is in place until the CDWR power contracts expire, which is currently expected to occur in 2013.[49]

As the Ruling recognizes, the rate design restrictions required by Section 80110 will impede the ability to derive substantial benefits from the demand response full deployment scenario in the years prior to 2014. This is because rates simply cannot be designed to reflect critical peak or time-of-use price signals for a residential customer's entire usage given that those customers' usage up to 130 percent of baseline could not be subject to a dynamic price. 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. As a result, any demand response contributions these customers could make will never be realized and thus, the AMI demand response benefits will be reduced.

We are concerned about inappropriately using analytical results based on rate structures that do not comply with the law, given that the analysis will incorrectly account for demand response that cannot occur as long as Section 80110 is in effect. If Section 80110 remains in place as well as the Commission's current interpretation thereof, dynamic pricing schedules under a default or mandatory tariff enrollment would not be allowed until 2014. Therefore, in those

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48 Ruling, p. 3.

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

cases, demand response benefits would not occur until 2014, drastically reducing the potential demand response benefits of AMI.

The CEC staff has suggested that Section 80110 could be interpreted to apply to monthly bills rather than rates. We have not analyzed how price differentiated tariffs would work nor what the effect would be on demand response under this alternative interpretation other than it would still be very problematic. About seventy percent of SCE's residential kWh sales are to customers with monthly usage at or below 130 percent of their baseline allowance. It is not clear how a dynamic rate program would apply to customers whose monthly bill is capped. Also, it is not clear how dynamic prices would apply to customers whose usage is near the 130 percent threshold. How would they respond to a dynamic price that may or may not increase their monthly bill? Finally, the SPP experiment did not cover a scenario or rate design with AB1-X in place, so the elasticity effects and load reductions from the experiment are significantly overstated unless the restrictions are removed.

F. The Reliability of Demand Response Must Be Better Understood

Generally, customers tend to reduce their purchases of a commodity when faced with higher prices. The SPP experiment for 2003 provided certain estimates of customer behavior under CPP-F rates for residential customers statewide, under CPP-V for select residential customers in SDG&E's service territory, and under CPP-V for small commercial customers in SCE's service territory. CPP-V customers were equipped with smart thermostats that aided customer response to CPP events. The observed behavior in the SPP was within the range of customer price elasticity estimates found in the relevant literature.

The California SPP experiment – although limited in scope – likely provides more reliable estimates of price elasticity for electricity than an approach that derives likely customer behavior from past research of different rate structures from other parts of the world. Numerous studies of customer response to TDRs have been performed since the energy crisis of the 1970s. The parameters of those studies varied widely, as did the results. The SPP experiment observed Californians in the current economy and employed parameters more closely resembling a potential AMI deployment. We used the SPP results as a basis for estimating demand response to the dynamic pricing scenarios. However, there are still 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:

1) Persistence: The SPP results for 2003 are important, but additional study is needed to fully understand their persistence. Because AMI is a fifteen-year investment, sustained behavior, and therefore sustained demand response benefits, is critical. For example, the SPP experiment in 2003 and 2004 did not include any extended heat storms (more than 4 days) or highly unusual weather. The number of summer cooling degree days in 2003 and 2004 were 923 and 858, respectively. This is slightly cooler than the 1994-2003 period, for which the ten-year average was 1,050. How customers would respond to CPP events after several days of an extended heat storm or over a very hot summer is not yet known. Also, it is unknown whether customers will respond more or less to TDRs over time. Long-run price elasticities tend to be higher than short-run elasticities, suggesting that demand reductions would grow as customers make home improvements or make permanent behavior adjustments. However, long-run elasticities have only been examined in the literature for TOU rates. It is unclear what long-run elasticities might apply given the unique aspects of CPP

rates, namely that they are subject to regulatory change in parameters such as notice, times struck and duration of events.

2) Applicability of SPP Results: SPP results reflect customers who voluntarily selected the rates (opted in) and were provided a substantial participation incentive. The statistically significant results were limited to CPP-F rates. TOU rates were tested but the sample size was too small to provide statistically significant results. CPP-V rates were tested but the treatment groups were not representative for application in the business case.

The estimates of price elasticity in contemporary literature vary widely. Although the SPP observed behavior is the most relevant for estimation in this preliminary analysis, actual customer behavior could vary significantly according to the prior research.[50]

Our proposed CPP-F revenue-neutral rates have a price ratio of fourteen to one between the critical-peak price and the off-peak-price. The SPP experiment used rates with a price ratio of about five to one. A higher price ratio is thought to result in greater demand response, but this cannot be confirmed by SPP results. We estimated a higher demand response under the proposed rate using the CRA demand reduction simulation tool[51] compared to the SPP rates. We also did preliminary analysis of rates similar to the SPP rates for SCE and found the demand response to be lower than the rates we propose herein. We

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[50] 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.

[51] Charles River Associates, Inc. Pricing Impacts Simulator Model (PRISM). PRISM results show that the higher the price differential, the higher the demand response.

recognize that we are likely pushing the CRA simulation tool beyond its reasonable limits thereby increasing the range of probable results. The customer acceptability of the proposed rates and the actual demand response has not been tested.

Appendix A

Estimating Preliminary Demand Savings from Potential Real Time Pricing

APPENDIX A

ESTIMATING PRELIMINARY DEMAND SAVINGS FROM POTENTIAL REAL TIME PRICING

This Appendix describes how SCE developed a preliminary estimate of the MW savings at system peak from firm and interruptible customers who would potentially be on RTP rates. The Ruling required a business case analysis of two-part RTP rates but we were unable to perform such an analysis. Instead we analyzed the effect of a single part RTP rate.

Our basic approach was to start with the results of the study that Christensen Associates performed for the California Energy Commission (CEC)[52] 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.

We considered two scenarios, one in which all customers over 200 kW were moved to an RTP tariff, and one in which those customers currently served on an interruptible rate (I-6) remained on the interruptible rate and those served on any of the firm rates were moved to an RTP tariff.

A. 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

[52] Potential Impact of Real-Time Pricing in California, by Steve Braithwait and David Armstrong (Christensen Associates), January 14, 2004.

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% of the total load for the group on the very high price days) represent the expected statewide savings.

B. 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 find no evidence of agricultural customers being served on RTP rates anywhere in the literature, so there was nothing upon which to base the 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.

C. <u>Determining Load Reductions by SIC Group</u>

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 B

Estimating the Value of Service Loss

APPENDIX B

ESTIMATING THE VALUE OF SERVICE LOSS

This appendix describes the method we used to estimate the value of the loss of service as described in Section IV of 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 equations can be expressed as follows:

Table 2-18
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 various revised preliminary business case analyses set forth in Volumes 3 and 4 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 which is 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 fifteen cents to a "real time price" of twenty-five 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 fifteen cents, but less than twenty-five 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 twenty cents, the simple average of the flat rate and real time price. Therefore, we can infer a value of $20 to the foregone consumption (twenty cents times 100 kWh).

This approach is consistent with the economics literature addressing time of use and real-time pricing. Acton and Bridger,[53] and Borenstein, Jaske and Rosenfeld,[54] 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:

$$\Delta \text{ Societal Benefit} = -\tfrac{1}{2}\Delta P_1 \Delta Q_1 - \tfrac{1}{2}\Delta P_2 \Delta Q_2$$

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[53] Acton, Jan Paul and Bridger M Mitchell. "Welfare Analysis and Electricity Rate Changes," The Rand Foundation Note # N-2010-HF/FF/NSF, May 1983.

[54] 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.

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 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:

Δ Resource Cost Savings = $-P_1 \Delta Q_1 - P_2 \Delta Q_2$

Δ Value of Service Loss = $-(P_1 - \frac{1}{2} \Delta P_1 \Delta Q_1) - (P_2 - \frac{1}{2} \Delta P_2 \Delta Q_2)$

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. <u>Results of Calculation</u>

The values that result from the calculation method above are contained in the following table.

Table 2-19
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***
3	$67.4	($13.8)	$53.5	$119.2	$14.1	$79.8
4	$197.6	($36.4)	$161.2	$326.1	$41.0	$205.9
5	$78.4	($0.3)	$78.1	$148.5	$19.3	$89.7
6	$87.4	($8.9)	$78.5	$146.6	$18.6	$86.7
7***	$197.6	($36.4)	$161.2	$466.2	$59.2	$364.2
8***	$78.4	($0.3)	$78.1	$493.7	$63.7	$479.3
12**	**	**	**	$224.2	$31.0	$255.2**
13**	**	**	**	$442.7	$61.3	$504.0 **
16	$8.5	($3.2)	$5.3	$16.6	$1.9	$13.3
17	$18.9	($3.7)	$15.2	$39.3	$4.9	$29.0
18	$10.4	($0.005)	$10.4	$20.3	$2.7	$12.6
19	$11.6	($1.0)	$10.5	$22.2	$2.8	$14.4
20***	$10.4	($0.005)	$10.4	$418.6	$53.8	$462.1
21***	$11.6	($1.1)	$10.5	$420.5	$54.0	$463.9

* Totals may not add due to rounding error.
** Value of service loss also applies to this scenario but has not yet been calculated.
*** Value of service loss for the ALC portion of demand response may apply, but has not been calculated.

Appendix C

Rate Design and Bill Impact Analysis

APPENDIX C

RATE DESIGN AND BILL IMPACT ANALYSIS

This Appendix describes the process we employed to design the experimental/existing CPP rate structures. This Appendix also describes our approach to and results of our analysis of bill impacts expected from these experimental CPP rate structures.

A. Rate Design Process

1. Domestic (Residential) Rate Design Process

Two sets of residential rates for the AMI business case scenarios were developed 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 AB1-X provisions, and the second ignoring the AB1-X restrictions. In the non-AB1-X 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 AB1-X 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 twelve-month period ending April 2004, seventy-four percent of SCE's residential customers' usage was billed at or below 130 percent of baseline (Tiers 1 and Tier 2). In fact, about thirty-four 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 AB1-X compliant case.

For both sets of rates, the existing D-TOU-2 rate option[55] 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 seventy-five 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 twelve Summer Peak days and three Winter Peak days at five hours per CPP Event day, for a total of seventy-five CPP hours annually. The D-TOU-CPP-V rate was also modeled after the existing experimental TOU-D-CPP-F rate using twelve Summer Peak days and three Winter Peak days with only three hours per CPP Event between the hours of 2:00 p.m. to 5:00 p.m., for a total of forty-five CPP hours annually. The D-TOU-CPP-P rate used the basic

[55] D-TOU-2 is a modified form of TOU-D-1 to account for variations of seasonal and peak period designations

tiered residential rate with a CPP adder based on twelve Summer Peak days and three Winter Peak days at five hours per CPP Event, for a total of seventy-five 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 ninety 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 twelve Summer Peak days and three Winter Peak days at six hours per CPP Event, for a total of ninety CPP hours annually.

GS-1-CPP-V was modeled after the existing experimental GS-1-CPPV rate, based on twelve Summer Peak days and three Winter Peak days with three hours per CPP Event between the hours of 2:00 p.m. to 5:00 p.m., for a total of forty-five CPP hours annually.

GS-1-CPP-P was based on twelve Summer Peak days and three Winter Peak days at six hours per CPP Event, for a total of ninety CPP event hours annually. To preserve revenue neutrality, the added revenue resulting from CPP events resulted in a reduction to the OAT energy charges.

3. <u>GS-2 Rate Design Process</u>

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 ninety 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 twelve Summer Peak days and three Winter Peak days at six hours per CPP Event, for a total of ninety CPP hours annually. GS-2-CPP-V is modeled after the existing GS-2-CPP rate using twelve Summer Peak days and three Winter Peak days at three hours per CPP Event between the hours of 2:00 p.m. to 5:00 p.m., for a total of forty-five CPP hours annually. GS-2-CPP-P is based on twelve Summer Peak days and three Winter Peak days at six hours per CPP Event, for a total of ninety 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 2-20
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	

A. Bill Impact Analysis

1. Residential Bill Impacts

Residential bill impacts, which are incorporated into the MMI simulation tool, provide the basis for estimating customer adoption rates for TDRs for Opt-in scenarios. 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 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 2-2 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 AB1-X price cap results in low usage customers experiencing the largest percentage bill increases. Most of the nearly fifteen percent of customers experiencing an annual bill increase of at least fourteen percent are lower usage customers (see Table 2-21). 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 2-22).

Figure 2-2
Annual Bill Impacts for Residential Customers – Assuming No Load Reductions

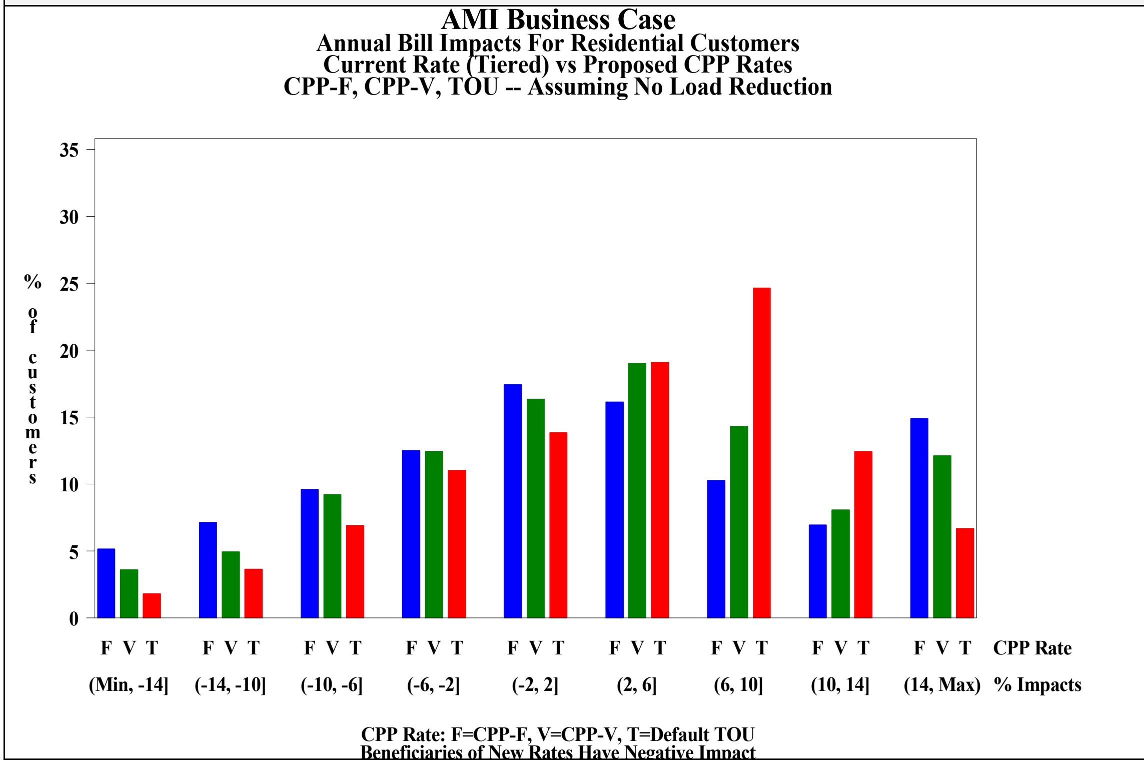


Table 2-21
Residential Bill Impacts - Tiered vs. CPP-F -Percentage Distribution of Accounts by Average Monthly Usage and Percent of Bill Impact

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	1.9	4.9	10.1	10.9	6.1	3.0	6.3	44.9
401 - 800 kWh	1.6	4.0	5.2	5.4	5.3	3.7	3.2	3.1	7.6	39.1
> 800 kWh	3.1	2.0	2.5	2.1	2.0	1.6	1.0	0.8	1.0	16.1

Note: Positive bill impacts indicate a higher CPP-F bill relative to the tiered OAT.

Table 2-22
Residential Bill Impacts Tiered vs. CPP-F
Percentage Distribution of Accounts by Climate Zone and Percent of Bill Impact

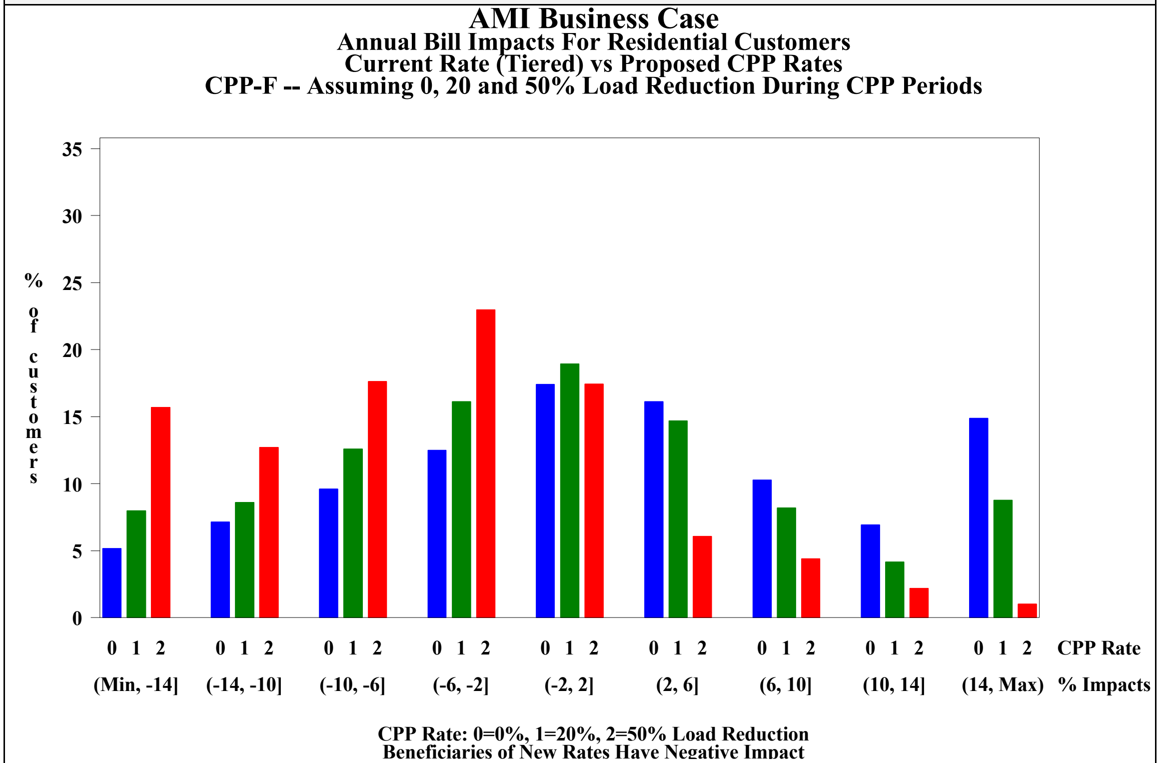
Climate Zone	(Min, -14]	(-14, -10]	(-10, -6]	(-6, -2]	(-2, 2]	(2, 6]	(6, 10]	(10, 14]	(14, Max)	Total
2	3.5	4.7	4.9	6.9	9.1	8.5	4.1	1.4	1.5	44.7
3	1.2	2.2	3.8	4.7	7.1	6.4	5.0	4.8	11.3	46.5
4	0.4	0.2	0.9	0.9	1.2	1.2	1.2	0.7	2.0	8.8
Total	5.2	7.1	9.6	12.5	17.4	16.1	10.3	6.9	14.9	100.0

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 2-3 below displays three annual bill impact distributions (CPP-F non AB1-X 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 ten percent annual bill increase is above twenty-two 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 twenty percent load reduction level, typical of the maximum load reductions seen in the SPP pilot, about thirteen percent of residential customers still see bill increases of more than ten percent while only about sixteen percent of our customers would see an annual bill decrease of at least ten percent.

Figure 2-3
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 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 (seventy-five 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 this type of minimal billing impact despite significant load shifting/reduction is exactly 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.[56]

Exit interviews of the SPP customers 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 fifty 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 2-4 displays similar information using the CPP-V rate design.

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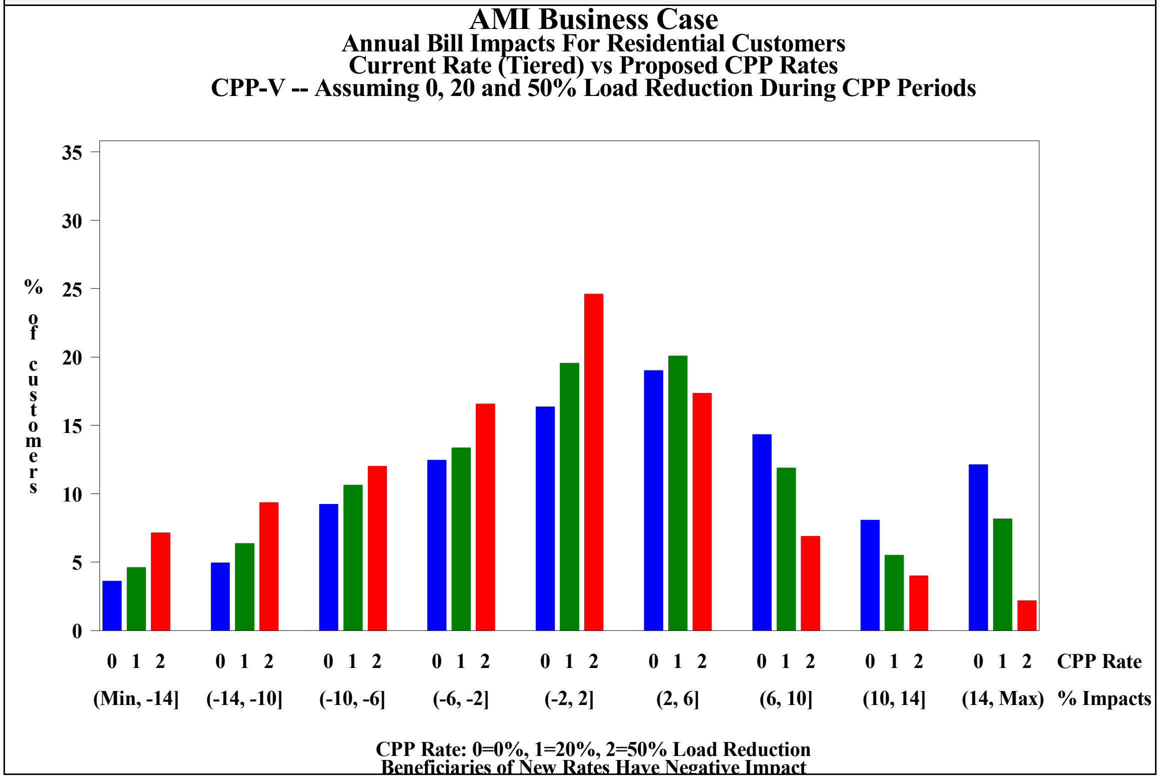
[56] Williamson, Craig, "Primen Perspective: Puget Sound Energy and Residential Time-of-Use Rates – What Happened?," Energy Use Series, Volume 1, Issue 10, December 2002.

Figure 2-4
Annual Bill Impacts For Residential Customers –
Assuming Load Reductions During CPP-V Periods

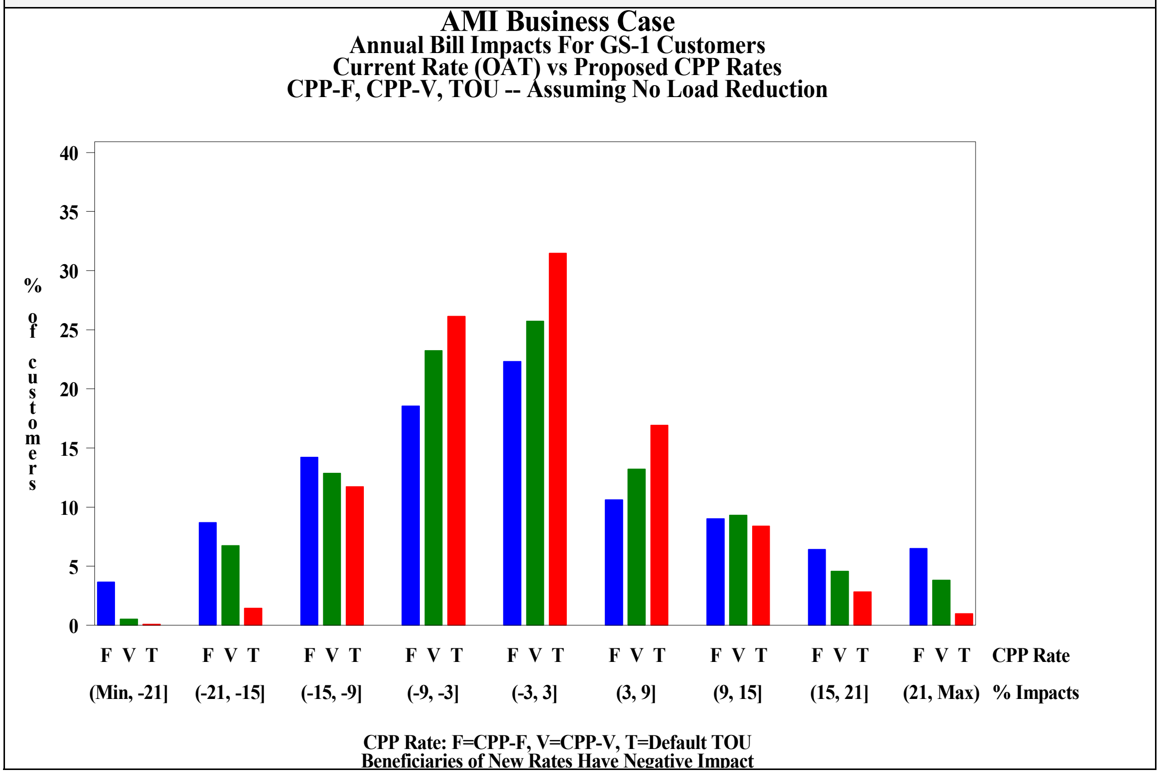


2. Commercial Bill Impacts

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 Statewide Pricing Pilot (SPP) sample data to gauge these impacts due to their larger sample sizes and to eliminate any impacts of participation bias.

Figure 2-5 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 twenty-five percent of GS-1 customers will experience an annual bill increase of at least nine percent, while about twenty 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 2-5
Annual Bill Impacts for GS-1 Customers – Assuming No Load Reduction



Figures 2-6 and 2-7 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 twenty percent and fifty 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 2-6
Annual Bill Impacts for GS-1 Customers –
Assuming Load Reductions During CPP-F Periods

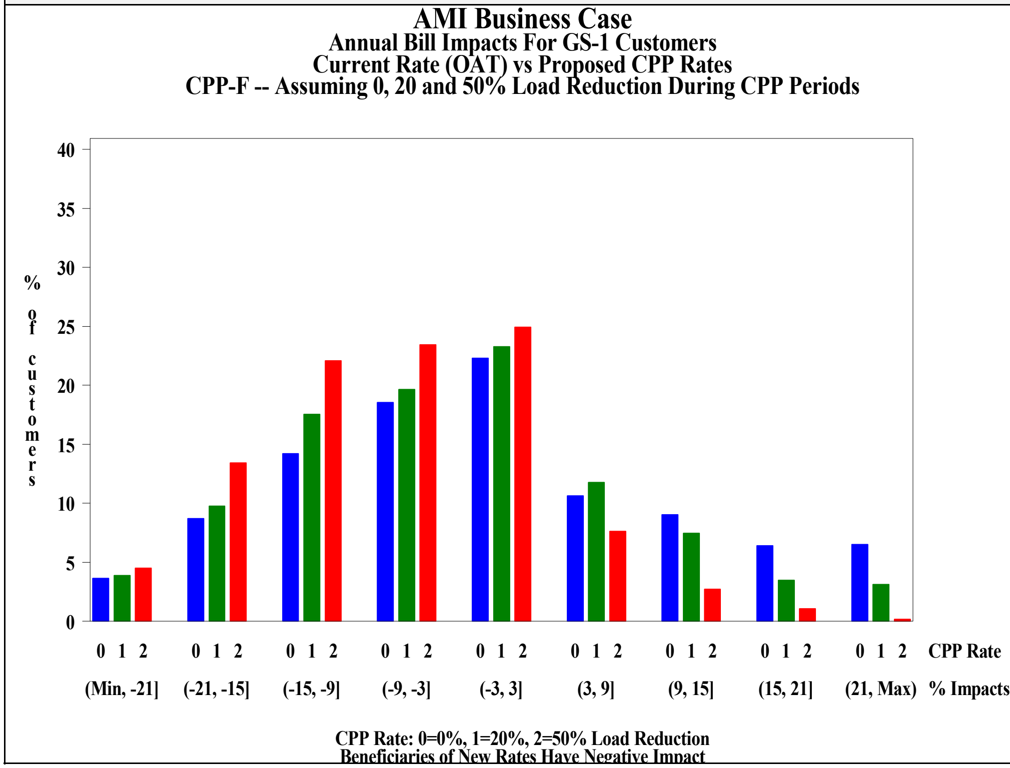


Figure 2-7
Annual Bill Impacts for GS-1 Customers –
Assuming Load Reductions During CPP-V Periods

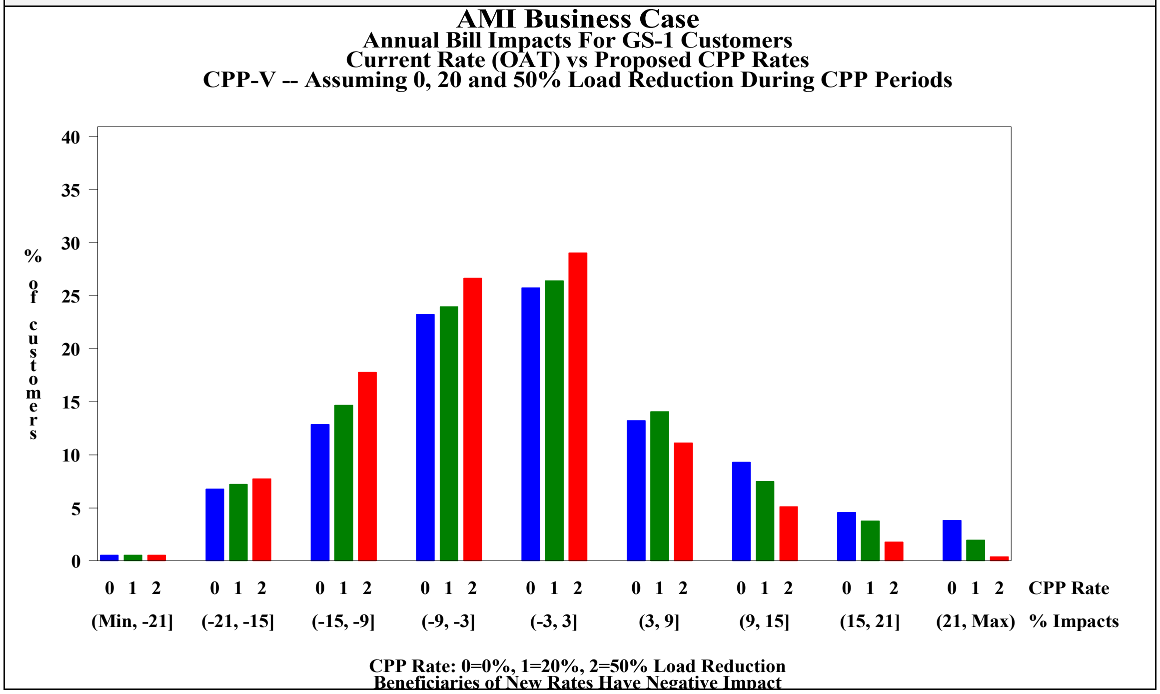


Figure 2-8 displays bill impact distributions for the medium commercial (GS-2) population for the CPP-F, CPP-V, CPP-P and TOU rate schedules relative to the current GS-2 rate. Again, no load shifting as a result of price response was assumed here. Compared to the GS-1 bill impact distributions, the GS-2 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 2-9 and 2-10 show that the largest bill impacts occur when customers shift fifty percent of their energy consumption out of CPP-F and CPP-V periods. The magnitude of the bill impacts, under the twenty percent reduction scenarios is somewhat subdued as only about eleven percent of these customers realize an annual bill reduction of nine percent or more.

Figure 2-8
Annual Bill Impacts for GS-2 Customers –
Assuming No Load Reduction

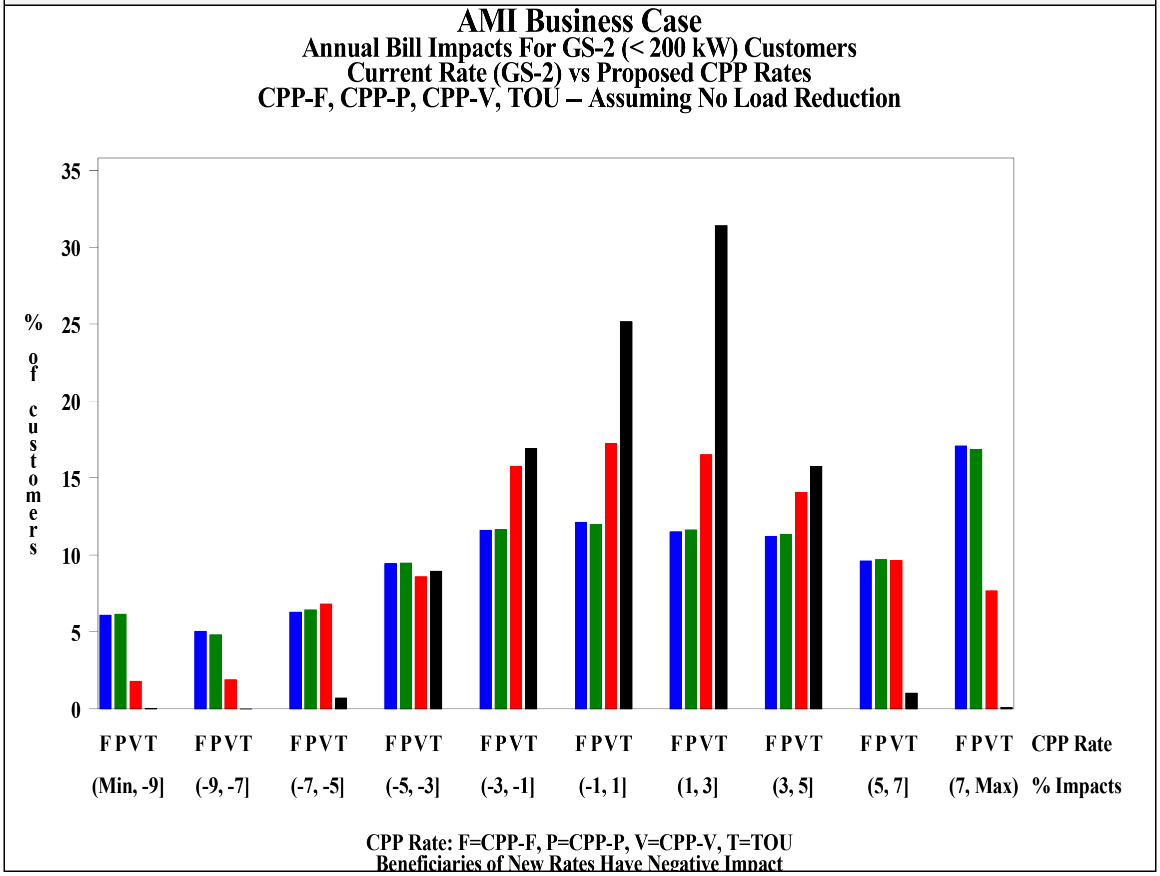


Figure 2-9
Annual Bill Impacts for GS-2 Customers –
Assuming Load Reductions During CPP-F Periods

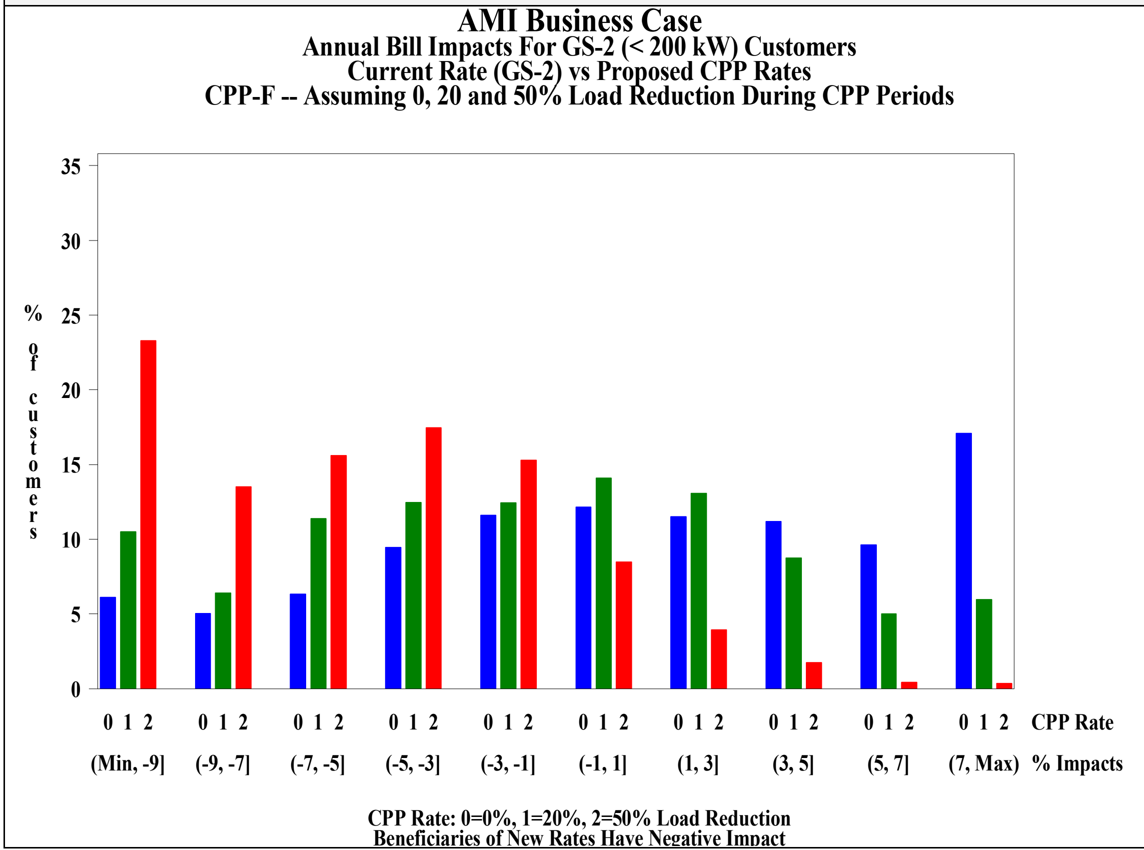
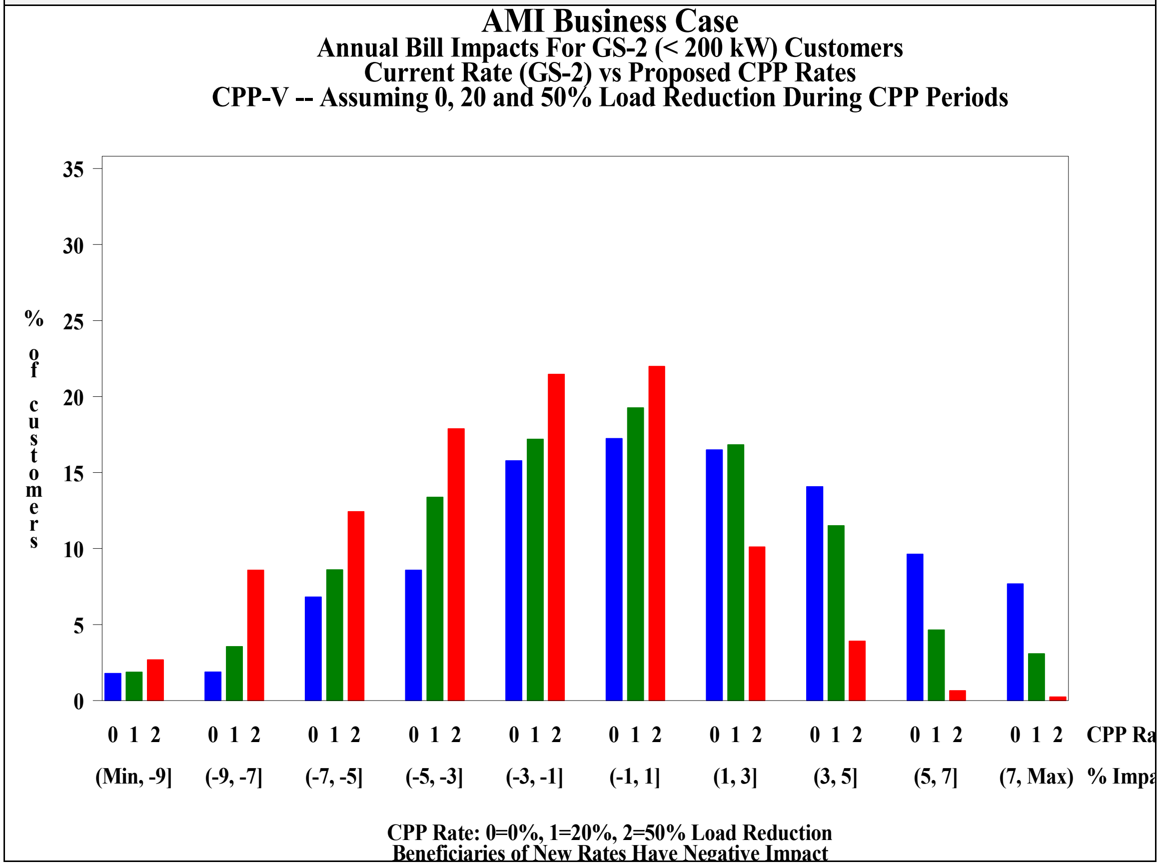


Figure 2-10
Annual Bill Impacts for GS-2 Customers –
Assuming Load Reductions During CPP-V Periods



Appendix D

Method for Estimating Load Impact Standard Errors

APPENDIX D

METHOD FOR ESTIMATING LOAD IMPACT STANDARD ERRORS

The purpose of this appendix is to describe the process we used estimate the standard errors of the load impacts due to CPP and TOU pricing for use in this revised preliminary analysis.

A. Statistical Models Used

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 related to 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.

Per our request, CRA provided the "variance-covariance matrix" for the parameters from the Elasticity of Substitution model. This model includes two separate, independently fit models to look at the change in usage due to the change in price, while controlling for weather and CAC saturation. Each of these models includes four coefficients plus one coefficient for each customer (the fixed effect for each customer). Since the elasticity parameters depend only on the changes in price and usage, not the magnitude of the actual prices and usage, only three of the coefficients are needed to calculate the elasticity parameters. These three are the coefficient on the price ratio, the coefficient on the interaction between the price ratio and the CAC saturation, and the interaction between the price ratio and the degree hour information.

B. Results of Statistical Models

The estimation and variance analysis for the two different elasticity parameters are very similar, though not identical. Because of this, we describe the variance analysis for the ES estimate, but not the derivation for the Daily estimate. We made the same assumption that CRA made in estimating these models, which is that the Daily and ES estimates are independent. While CRA has since estimated the two values simultaneously, they did not do so for the modeling approach used in the August 9 report, which is the basis of the analysis in this version of the business case.

1. Elasticity of Substitution Model

The ES value is estimated using the following equation from the final August 9 CRA report:[57]

$$ES = \sigma + \lambda (CDH_p - CDH_{op}) + \Phi \; (CAC)$$

[57] This is Equation (4) in section 4.2.1 in "Statewide Pricing Pilot – Summer 2003 Impact Analysis," by Charles River Associates, August 9, 2004.

Where CDH_p is the average number of cooling degree hours per hour during the peak period,

CDH_{op} is the average number of cooling degree hours per hour during the off-peak period,

$\sigma, \lambda, and\, \Phi$ are the coefficient estimates from the model.

Because the model is a statistical regression model, the coefficients are estimates that can be assumed to be normally distributed with a mean equal to the true (but unknown) value of the parameter, and a variance that can be estimated based on the model. CRA provided the variance-covariance matrix from the model estimation, which includes the variance of each of the coefficients, and the covariance between all possible pairs of coefficients.

Using conventional variance formulas,[58] we get the following result:

$$\mathrm{Var(ES)} = \mathrm{var}[\sigma + \lambda\,(CDH_p - CDH_{op}) + \Phi\,(CAC)]$$
$$= \mathrm{var}(\sigma) + (CDH_p - CDH_{op})^2\mathrm{var}(\lambda) + CAC^2\mathrm{var}(\Phi) + 2(CAC)\mathrm{cov}(\sigma,\Phi)$$
$$+ 2(CDH_p - CDH_{op})\mathrm{cov}(\sigma,\lambda) + 2(CAC)\,(CDH_p - CDH_{op})\mathrm{cov}(\lambda,\Phi)$$

We then calculated the variance using this expression, the variance-covariance matrix, and the CDH and CAC values for each weather zone. Note that like the estimates themselves, the variances (and hence the standard errors) depend on the CDH and CAC values.

We also calculated the variance of the estimate of Daily elasticity. We then took the square root of the variance to get the standard error. Using this standard error, we calculated a *t*-value and assess the significance of the two elasticity values for each weather zone.

The formula to calculate the load impact is complicated. First, the usage reduction for the day is calculated using the daily elasticity, the price change,

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[58] *See, e.g.,* Mood, Graybill, & Boes, "Introduction to the Theory of Statistics," 3rd edition, McGraw Hill, 1974.

and the original daily usage. Second, the shift in load is calculated using the ES estimate, the on and off peak price changes, and the original on and off peak usage. Next, the distribution of the load impact is determined. The regression model coefficients ($\sigma, \lambda, and\ \Phi$) are approximately normally distributed, so the elasticity parameters, which are linear combinations of normally distributed estimates, are also normally distributed. The equations to calculate the load impacts involve exponentiation, thus the daily usage is approximately lognormally distributed. The reduction in peak usage is not in any conventional distribution.

2. Monte Carlo Simulation Model

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% confidence interval on the load response.

We can calculate standard errors for the load impacts as well, but care must be used when interpreting these standard errors. Because the load impacts are not necessarily normally distributed, *t*-tests and *t*-statistics do not have the same meaning. By looking at the distribution, and using confidence intervals, we can make conclusions about significance. We cannot simply calculate a *t*-value and use it to determine significance.

Peak supply resources are generally assumed to be available 95% of the time when called on for planning purposes. To treat the load response consistently, we used the lower end of the one-sided 95% confidence interval peak kW reduction to determine capacity savings. This is the value that will be available with 95% certainty when called upon.

The results of our Monte Carlo analysis for capacity planning in each zone are shown in Table 2-23 below.

Table 2-23
Monte Carlo Analysis for Capacity Planning

Zone	PRISM Peak kW Impact	95th Percentile Peak kW Impact
2	-.1201	-.1046
3	-.4046	-.3581
4	-.4498	-.3699

This analysis quantifies the uncertainty due to model estimation. The distribution indicates the variability that we can expect to see in the load impact resulting from model uncertainty. There are other factors with uncertainty that impact the value of the peak reduction, but they are dealt with in a separate analysis that looks at the resource availability (the number of times an event can be called, the likelihood of calling an event on the “right” day, *etc.*) in the value of capacity section.

To calculate energy savings, we used the entire distribution of the load impact estimate, as developed using the Monte Carlo simulation. This is appropriate because energy is expected to be more variable, while the capacity value needs more certainty.

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(U 338-E)

Advanced Metering Infrastructure Revised Preliminary Business Case Analysis

Volume 3 – Revised Preliminary Analysis of Full Deployment Business Case Scenarios

Before the
Public Utilities Commission of the State of California

Rosemead, California
January 12, 2005

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) REVISED PRELIMINARY ANALYSIS OF ADVANCED METERING INFRASTRUCTURE BUSINESS CASE

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I.

INTRODUCTION

The purpose of this volume is to present a detailed revised preliminary business case analysis as required by the Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure (AMI) issued on July 21, 2004 (Ruling). This volume sets forth our business case analysis of full deployment of AMI on a scenario-by-scenario basis as identified in Attachment A of the Ruling.

Attachment A of the Ruling identified eight different full deployment scenarios for the utilities to analyze. In our preliminary analysis filed on October 22, 2004, we provided three additional scenarios containing what we believe to be more reasonable assumptions about customer participation rates on the various time-differentiated default rates. In this revised preliminary business case analysis, we have eliminated these three additional full deployment scenarios, choosing to incorporate the effect of less-than-full customer awareness of rate options as part of the demand response benefit for each of the opt-out scenarios.

Section II of this volume describes the expected impacts on our various business processes, operations and systems resulting from the full deployment scenarios using the AMI technology solution described previously in Volume 2.

Based on these impacts, Section III of this volume provides detailed cost analysis in the Ruling's three major analytical categories (start-up and design; installation; and operations and maintenance) along with the five applicable cost categories[1] and seventy-nine individual cost codes associated with these cost categories. The benefit analysis is also provided in this section by the four major

[1] The 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.

benefit categories and the individual benefit codes that were actually used in this analysis. A summary discussion of all forty benefit codes, whether used or not, is contained in Appendix A of this volume. Section III also includes discussion of the risks and uncertainties identified to date and presents an NPV analysis, based on the costs and benefits identified, for each scenario.

Section IV of this volume sets forth the preliminary revenue requirement impacts for each full deployment scenario based on the detailed cost and benefits information provided in Section III. The impact on customer rates expected for each of the full deployment scenarios is also provided in Section IV.

Our October filing of this preliminary analysis disclosed a number of errors in Volumes 2 and 3 that, due to time constraints, could not be corrected at that time. In this revised preliminary analysis, we have attempted to correct all previously identified errors and omissions, along with other changes and updates discovered after the October 22, 2004 filing. These revisions do not have a material impact on the overall conclusions contained in this analysis.

II.

OVERVIEW OF FULL DEPLOYMENT BUSINESS CASE IMPACT

This section describes the effects of a full deployment case on all of SCE's operations, processes and information technology systems. As required by the Ruling, this section describes the functional capabilities of advanced meters and their supporting network using the RF technology solution described in Volume 2. This section also describes how full deployment would be achieved, a schedule of deployment, and how we will achieve the customer coverage required by the Ruling. To help facilitate the Commission's understanding of the implications of full deployment, this section describes the full deployment case according to its impact on our operations, using the Ruling's five applicable cost categories. The costs and benefits for each scenario of the full deployment case are discussed in Section III, on a scenario-by-scenario basis and quantified using the cost and benefit codes identified in Appendix A of the Ruling.

A. Metering System Installation and Maintenance Category

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

1. Number of Customers Receiving AMI Meters Under Full AMI Deployment

The Ruling requires that full AMI deployment reach no less than ninety percent of SCE's customers.[2] 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 discussed in Volume 2, Section III, 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. Given the short timeframe allowed for preparation of the business case analysis, we did not perform such a study. Instead, 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 ninety-seven percent of the existing meters (4.54 million meters) so that ninety percent of the total meters will communicate with the network, as required. We also estimate that approximately three percent of our meter population will not be included in the full 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.*, DA customer-owned meters). For the ninety-seven 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

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[2] Ruling, Attachment A., p. 6.

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.

a) Roll-Out Plans for Full Deployment

In order to fully deploy 4.54 million AMI meters in a five-year period, as contemplated in the Ruling, we will be required to pursue an extraordinarily aggressive deployment schedule throughout our service territory. Our service territory is comprised of twenty-four service centers servicing the densely populated metropolitan areas and ten service centers serving the expansive, yet sparsely populated, rural areas. Approximately ninety-eight percent of the 4.54 million meters to be deployed would be in service centers serving metropolitan areas. Accordingly, SCE decided to stage the startup of deployment to the 24 service centers, as depicted in Table 3-1.

Table 3-1 **Full Deployment Start Date by Service Center**			
Service Center	2nd Quarter - 2006	3rd Quarter - 2006	4th Quarter – 2006
Covina	X		
Long Beach	X		
San Jacinto Valley	X		
Compton	X		
Ventura	X		
San Joaquin	X		
Foothill		X	
Fullerton		X	
Santa Ana		X	
Huntington Beach		X	
Ontario		X	
South Bay		X	
Thousand Oaks		X	
Antelope Valley		X	
Saddleback			X
Redlands			X
Palm Springs			X
Montebello			X
Monrovia			X
Santa Monica			X
Santa Barbara			X
Valencia			X
Victorville			X
Whittier			X

As shown above, the full deployment process will begin in the second quarter of 2006 and will start in the six largest service centers (*i.e.*, those largest in terms of number of meters eligible for deployment). Deployment efforts will be expanded to eight additional service centers in the third quarter of 2006. Deployment efforts will be expanded to the remaining ten service centers in the fourth quarter of 2006.

This deployment strategy considered meter densities, as well as concentrations of already deployed AMR meters. As discussed in Volume 2, Section

II, we have already deployed AMR throughout our service territory, concentrating in those areas where it was most cost-effective to do so. 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 as set forth in the Ruling, we expect to replace these AMR meters with AMI meters and terminate prematurely the meter reading contract. In order to mitigate the effect of full deployment on this investment in AMR, we considered the concentration of AMR meters associated with each service center. We will begin replacing the AMR meters as late in the five-year deployment as possible in order to mitigate costs associated with stranding this investment. We expect to complete deployment in all of the twenty-four service center areas by the second quarter of 2010, as directed by the Ruling.

For the ten service centers that serve the rural areas of our service territory, full deployment will begin in the second quarter of 2006 and will be completed by the end of 2010. As discussed in Section III, in order to mitigate costs with full deployment in the rural areas, we expect to have one installer in each service center beginning in the second quarter of 2006.

b) <u>Annual Deployment Volumes</u>

Table 3-2 shows the annual volumes of AMI meters by customer class under the full deployment case.

Table 3-2 Annual Deployment Volumes by Customer Class			
	Customer Class		
Year	Residential and Small Commercial	Commercial and Agricultural (20 kW - 200 kW)	TOTALS BY YEAR
2006	508,335	41,823	550,158
2007	1,071,259	54,214	1,125,473
2008	1,072,524	57,312	1,129,836
2009	1,080,269	60,410	1,140,679
2010	532,515	61,508	594,023
Total	4,264,902	275,267	4,540,169

2. Description of Meter System Installation and Maintenance Activities Affected by Full Deployment

The meter system installation and maintenance category involves all of our activities associated with meter procurement, supply chain management, testing, installation and other support. The effect of full 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 will procure five 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. First, under a new process, 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 the initial receipt of the meter from the vendor all the way through the dissemination of the meter to field personnel for installation. In addition, we will need to procure meter lock rings that will be installed on each meter at the time of deployment.

Finally, we will also need to procure external antennas for those meters requiring such installation at the time of deployment.

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, PAMM will increase its meter distribution to a peak of approximately 1.3 million meters a year. In addition, it is estimated that there will be approximately 1.5 million additional meters that will need to be processed from 2006 to 2021 due to meter replacements that result from failures in the field. The estimated number of meter failures by year end under full deployment is shown in Table 3-3 below.

Table 3-3 Estimated Meter Failures by Year	
Year	**Estimated Meter Failures**
2006	21,379
2007	167,893
2008	142,724
2009	120,071
2010	92,025
2011	91,863
2012	91,671
2013	91,451
2014	91,200
2015	90,926
2016	90,628
2017	90,305
2018	89,960
2019	89,594
2020	89,206
2021	88,799
Total	1,539,692

Given our prior experience with meter vendor reliability and the massive scale of full deployment, 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 3-1, the distribution facility will need to begin stocking meters by the fourth quarter of 2005. 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 April 2006.

Under full deployment, 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 also reduce secure storage requirements. Additional personnel will be required in the service centers to process the meters when they are received. The meters are then to be stored in a secure area until they are scheduled for distribution. Due to the short-term nature of this project, we propose to use a Temporary Project Accountant position to process meters at the service centers.[3] 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 the existing meters with new AMI meters, the returned meters will be processed at the various service centers for salvage purposes.

c) **Meter Testing**

For residential meters, we plan to test 100 percent of the first two meter shipments 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 full deployment of AMI will reduce some existing meter testing work, the meter testing workload will increase overall because of the scale and pace of full deployment. As such, additional personnel will be required to handle this increased testing.

d) **Meter Installation**

(1) **Residential and small commercial (less than 20 kW)**

As discussed in detail in Volume 2, Section III, communications network and information technology applications related to AMI

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

will not be operational until June 2007. Prior to that date, we expect to continue our current meter reading and field service practices for all meters, even those that receive an AMI meter before June 2007.[4] We analyzed various methods to handle the AMI installations and continue our existing field work. Because full deployment is short-term in nature, we determined that it would be more cost effective to hire temporary personnel rather than full-time personnel so as to avoid incurring severance costs for full time resources when the deployment concludes. The use of 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 a "Project Temporary Installer" job classification.[5] Another full deployment impact in this area is the use of mandatory overtime. 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 are therefore handled by Meter Technicians with specialty training. These complex meters are associated with Rate Schedule GS-2 and accounts with monthly demands above 20 kW. These also include 240v three-phase accounts and residential accounts with current transformers and potential transformers. In order to support the aggressive full deployment

[4] As described in Section III of Volume 2, in addition to manually-read meters, we currently have over 350,000 AMR meters that are being read via van-based automated meter reading. In addition, we currently collect interval data on a daily basis from more than 12,000 commercial customers with RTEMs.

[5] IBEW approved the use of the project temporary meter reader job classification for the AMR deployment which took place in 2000. We understand that the use of non-union labor on utility construction projects is currently under Commission review and thus, if represented employee labor were required, the cost estimates for meter installation could change.

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.

e) Support Related Costs

In order to support AMI deployment, our field personnel will need to attend various training classes. As new meter readers are hired to 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 positions, to backfill for those who have taken Project Temporary Installer positions, they will need to take classes on handling billing inquiries and using various customer service systems. Project Temporary Installers, who will handle the meter installations for the residential and less than 20 kW commercial accounts, will need to undergo a training program that covers the Meter Installation Procedures and Practices manual as well as training on how to use our meter tracking systems.

B. Communications Infrastructure

As detailed in Volume 2, Section III, the radio frequency communications system selected for full deployment will be comprised of collectors, packet routers, and Metricom Communication Controller (MCC) take-out points. 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 ninety percent coverage requirement. Based upon our experience with the RF infrastructure currently operating within our service territory, we believe it is prudent to install an additional twenty percent, or 1,600 collectors if necessary to achieve the ninety percent coverage. As such, our business case analysis assumes the installation of 9,600 collectors.

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 to the overall AMI communications network. Given the large number of meters in full deployment, 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 ninety-six packet routers.

Installation of the 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 100 MCC take-out points we have in place today with 181 additional MCC take-out points.

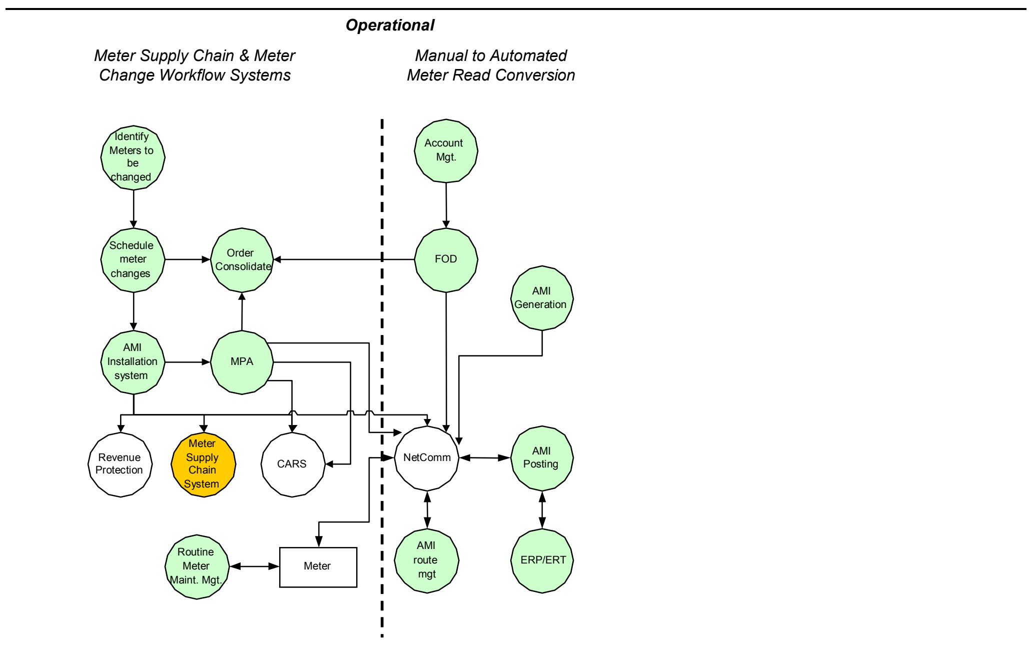
C. Information Technology Infrastructure

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 sections below.

1. Applications

Under full deployment, we will need to enhance certain existing IT systems and develop new ones. Figure 3-1 illustrates the IT systems that will be required for full deployment.

Figure 3-1
Full Deployment IT Systems Architecture



The IT systems that need to be developed or enhanced to support full 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 full deployment.

a) Meter Supply Chain Management

We will need to make changes to the Meter Supply Chain (MSC) System so that the following procurement processes can be automated under full deployment:

- Ordering 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 Centers for installation.

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 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 above in Figure 3-1, a number of new IT systems will be needed to handle the meter change workflow in the areas of:

- New Meter Identification;
- Meter Changes Order Scheduling;
- AMI Installation;
- Meter Order Consolidation; and

- Meter Process Automation.

First, a new system will be necessary to identify the meters that will be changed to the new AMI metering. The application will interface with the MSC system to identify the exact meters to be installed at a particular site.

Second, full deployment will require development of a new system 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 deployment. Therefore, a new system is required to handle the significant volume of meter changes associated with 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 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.

Third, full deployment will also require a new system to handle the collection of necessary meter information to properly route the meter installation request to the field personnel installing the AMI meter. This new AMI Installation (AMI-I) system will provide field personnel with the route information necessary to locate the meters that will be changed. As meter removals and installations are completed by field personnel, the AMI-I system will process completion information, including global positioning system (GPS) data, and deliver this information to the Meter Inventory system for further processing.

The AMI-I 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 Field Tool system. The users of the Field Tool will have the capability to view orders and input completion information. The Field Tool will also allow users to cancel or defer orders, if appropriate.

Fourth, as a result of full deployment, a new system is required to interface with the existing MPA system which currently schedules, tracks, and posts data on meter orders. The Order Consolidation (OC) system will be developed to examine various meter orders for the same installed service account, to consolidate them, and maximize operational efficiency.

Lastly, to accommodate full deployment, we expect to make enhancements to the existing MPA system. Enhancements are necessary because the current MPA system is not capable of managing the meter volumes expected in full deployment. An interface to the new AMI-I system will be required to provide a link to the MPA system. In addition, enhancements are required so that the MPA system can store GPS data that is being returned from the field to facilitate meter location tracking.

c) Meter Read Conversion

As shown in Figure 3-1, under full deployment, a number of new systems need to be developed to handle the meter read conversion. Additionally, enhancements to existing meter-related systems are required.

As a result of full deployment, 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. For full deployment, 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 not available 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 full deployment. The FOD system is currently responsible for the management of field visits related to metering and communications incidents that may include error detection, failures, and replacements. Enhancements will need to be developed to route field events from the FOD system to the AMI communications network support group and meter support groups.

Full 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.

We expect full deployment to require a new system 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.

Under full deployment, a new system is needed to collect meter read information from the 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 full 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. In addition, enhancements for 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 the software handling the full deployment AMI data. Computing Services includes the actual procurement and installation of the necessary infrastructure. Computing Services infrastructure and hardware 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;

- 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.

D. Customer Service Systems Category

This section describes the customer service operations, processes and systems that are affected by full deployment of AMI. These changes are needed to provide an adequate level of customer services essential to assuring efficient installation and operations of the full deployment of the AMI infrastructure and to assure a continued high level of services throughout the installation phase of AMI deployment. Specifically, the customer services 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 essential to the Meter System Installation and Maintenance costs discussed in Section II.A above.

1. Description of Billing Activities Affected by Full Deployment

SCE's Billing Organization currently processes and delivers over fifty-six 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 play a significant role in our AMI full deployment scenarios. Under full deployment of AMI, we will need to supplement the current billing system that depends primarily on manual reads in the field to a system that can generate a bill based on AMI data transmitted through the network communications. Billing Operations will also be affected due to the incremental replacement of an additional 1.5 million meters throughout the fifteen-year analysis period. We anticipated these meters will require replacement due to meter and communication failures.[6]

Under the "Operational-Only", full deployment scenario discussed in Section III below, we assume that we will read the vast majority of meters remotely only once per month and that there is no need for interval data beyond that which is collected today. Accordingly, the processes associated with aggregating, validating, and processing interval data are not affected in the Operational-Only scenario. As we discuss later in this volume, the processing of interval data has a significant impact on billing costs; this will be particularly evident in the Demand Response scenarios discussed in Section III below, where the majority of 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 monthly meter reads and requires an additional layer of validations and the resultant exception processing in order to assure the integrity of each fifteen-minute or hourly read.

At the outset of the Operational-Only full deployment case, 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. The largest effect of full 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

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[6] *See* Section II.A.2.b above and Table 3-3.

billing. Though small in terms of percentage of the total, the initial replacement of nearly five million meters will result in a significant increase in the number of billing exceptions being processed.

A major contributor to the increase in exception processing is the anticipated failure rate of AMI meters in the initial stages of full deployment. 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. This process becomes considerably more complex when 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.

We estimate that fifty percent of all meter failures will require exception processing within the Billing Organization. Meter failures are expected to peak at 168,000 in 2007, and drop to 92,000 by 2010. 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.

Another factor contributing to installation billing impacts is related to the development of new validation routines to replace the validations that currently take place in the field as meters are being read manually. 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.

Overall, under full deployment, we expect a slight improvement in metering accuracy. We also expect higher meter failure rates and the loss of field validations.

2. Description of Call Center Activities Affected by Full 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 ranging from a low of 50,000 calls per year for the Operational Only scenario to a high of 1.6 million calls per year for certain Demand Response scenarios. The majority of the anticipated call volume increases results from customers calling to inquire about the new time-differentiated rate in the Demand Response full deployment scenarios. Our 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 due to full deployment opt-out Demand Response, we estimated that seventy percent of the customers that call to inquire about opting-out would actually opt-out. 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, we feel we should be able to convince thirty percent of such callers to stick with the program.

We expect that as AMI is 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 in subsequent years 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 most scenarios.

E. Management and Miscellaneous Other

This section describes the overall Project Management and miscellaneous "other" costs not previously identified in other cost categories. Other costs include centralized training costs, personnel recruiting costs, employee communications, and miscellaneous start-up 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 the full deployment scenarios, 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 phase of the 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 twelve for the remainder of the installation phase (*i.e.*, 2007 -2010).

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 Ruling, with deployment starting in 2006 and full deployment by 2011, there will likely be project planning tasks that should occur in 2005. However, the 2005 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

Under the "Operational-Only" scenarios, 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 may feel is needed for purposes of public notification under the Operational-Only scenario would add incrementally to our estimated costs.

The costs associated with the addition of Demand Response options under the full deployment scenario will differ based on scenario, but the basic structure and approach to the media and information delivery campaign will be similar. The strategic approach of the campaign is to use an integrated mix of media designed to affect a long-term cultural and behavioral change. The campaign must be multi-year in order to positively affect long-term change. There are three tenets of the campaign: 1) raise awareness and educate customers about the program and its benefits as well as the behavioral changes required to comply with each specific Demand Response option; 2) develop and implement a strong and comprehensive acquisition effort to recruit customers and meet participation rate expectations; and 3) develop and implement a vigorous retention campaign to maintain the customer base over time. The media mix includes:

- Mass Media: Television, radio, and print for education and awareness;
- Targeted/Ethnic Media: Local print, cable television, and strategic partnerships (ethnic business chamber promotion) including the use of in-language media for education and awareness;
- Direct Communications: Bill inserts, direct mail, e-mail notification, voice mail notification, newsletters, face-to-face communication through the account management function for acquisition and retention; and
- "CPP Day" Notification: Use of phone banks, radio, public service announcements, and press releases/press relations to notify customers of CPP Demand Response events.

Each scenario includes a basic level of communication and outreach that is designed to reach 100 percent of our customers, and saturate the customer base with broad based educational campaign, as well as specifics on how customers can respond to time-differentiated rates. In addition to the messages contained in the campaign, each full deployment Demand Response scenario will require extensive research to understand consumer attitudes and adapt messaging appropriately for all geographic and ethnic groups prior to the delivery of the campaign.

The campaign will differ significantly from previously undertaken SCE campaigns, which are designed to create customer awareness and promote programs on a short term basis. This campaign will create customer awareness and education about behavioral changes required to comply with the chosen Demand Response option, with long-term behavioral and cultural change being essential to the program's success. One of the two main objectives of the campaign is to condition customers to understand why Demand Response requires a behavioral change and move them toward such behavioral change. Through education, we expect to achieve customer understanding of their energy usage and the impacts time-differentiated pricing options have on overall costs. This will be achieved through the customer-specific education portions of the campaign. The other main objective of the campaign is to recruit and retain customers to these Demand Response rate programs over time. This will be accomplished through the customer-specific acquisition and retention portions of the campaign.

The cost of the campaign is affected by our location and the customer base we serve. The greater Los Angeles area is the second largest and highest cost media market in the country. It is also both linguistically and culturally diverse.[7] As such, messages must be created and delivered in languages other than English. Additionally, thirty-five percent of our customer base has demonstrated a lack of interest in electricity issues other than when their power goes out.[8] 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.

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[7] 2003 – 2004 Nielson Universe Estimates, DMA Ranking and Advertising Age Magazine, July 24, 2000

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

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.[9]

4. Management and 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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[9] 2004, Nielson Media Research

III.

FULL AMI DEPLOYMENT BUSINESS CASE ANALYSIS

This section provides our revised full deployment business case analysis. This analysis includes the eight separate full deployment scenarios required by the Ruling. Table 3-4, below, identifies the full deployment scenarios for which we are providing business case analysis.[10]

Table 3-4
Listing of Full Deployment Scenarios

Scenario No.	Description
1	Full: Operational Only (SCE Implemented)
2	Full: Operational Only (Outsourced)
3	Full: Operational + DR (TOU Default with Opt-out)
4	Full: Operational + DR (CPP-F/V Default with Opt-out)
5	Full: Operational + DR (OAT Default with Opt-in to CPP Pure)
6	Full: Operational + DR (OAT Default with Opt-in to CPP-F/V)
7	Full: Operational + DR + Reliability (CPP-F/V Default with Opt-out)
8	Full: Operational + DR + Reliability (OAT Default with Opt-in to CPP Pure)

The following subsections describe the costs and benefits we expect to result from implementation of each scenario. These costs and benefits are described as "incremental" to our "Business As Usual" case, as presented in Volume 2. As previously described, "full deployment" means replacing ninety-seven percent of our existing 4.7 million meters over a five-year time period, and building the communications infrastructure to allow us to read ninety percent of these meters remotely.

[10] Our original AMI Preliminary Business Case Analysis, as filed in October, 2004, included three additional (optional) scenarios (Scenarios 9, 10 and 11). These three optional scenarios have been dropped from this revised analysis.

A. Scenario 1: Full Deployment Operational Only - Utility Implemented

In this subsection we describe the operational costs and benefits we expect to result from full deployment by SCE of the AMI metering and communications infrastructure. These 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. As required by the Ruling, "this scenario assumes that no new tariffs are established as a result of the full deployment of AMI, so costs and benefits that derive from the rollout of new tariffs are excluded in this case."[11] The operational activities, processes, and procedures affected by full deployment under this particular scenario were fully discussed in Section II above.

1. Costs

Appendix A of the 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). The Ruling also establishes seventy-nine different cost codes applicable to these cost categories that must be used for analytical purposes. Under the "Operation-Only" full deployment scenario, we expect to spend a total of $901.9 million, including operational and capital investment related costs.[12] Table 3-5 below summarizes our estimated costs for Scenario 1 in the five cost categories.

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[11] Ruling, Attachment A, p. 7.

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

Table 3-5 Summary of Costs for Scenario 1 (000s in 2004 Pre-Tax Present Value Dollars)	
Cost Categories	**Total**
Metering System Infrastructure	$667,983
Communications Infrastructure	39,500
Information Technology Infrastructure	127,696
Customer Service Systems	34,848
Management and Miscellaneous Other	31,851
TOTAL:	$901,878

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

a) Meter System Installation and Maintenance

(1) Start-up and Design

Appendix A to the Ruling does not identify any cost categories for meter system start-up or design. Any meter system start-up or design activities have been classified as installation costs and are discussed in the next subsection.

(2) Installation [MS-1 through MS-11]

The 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 preliminary analysis of the costs falling into each of those cost codes.

(a) Meter Reader Transition Costs (MS-1)

For the twenty-four service centers in our metropolitan areas, we assume that current Field Services Representatives (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 we 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% 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 ten 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 eighty percent of our current meter reading organization is expected to take place through normal attrition during the latter phases of AMI deployment with our current attrition rate of thirty-five to forty percent annually. Attrition is expected to ramp-up beginning with the activation of the AMI communications system (approximately eighteen months after AMI installations begin) and continue throughout the deployment years. Severance of thirty-two 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 twenty-four 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 six 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 to handle the new revenue protection investigators that will be hired (as discussed in cost code MS-12). We estimate the cost of these seventy-eight 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 six different meter types for the AMI deployment. Each meter will be equipped with an RFID tag to facilitate our procurement and supply chain processes. Sales tax was included in our estimated meter cost.

To achieve the ninety percent coverage required by the Ruling, we will procure 4.5 million meters to replace the existing meters throughout our service territory. Table 3-6 shows the types of meters, quantities, and unit costs associated with full deployment.

Table 3-6
Cost Table for Initial AMI Full Deployment Meter Purchases

Meter Type With Communication Module	Meter Quantity	Base Unit Cost	RFID Unit Cost
< 20 kW residential single phase	4,112,000	$50	$2
< 20 kW network	117,000	$130	$2
< 20 kW 3 phase commercial and residential	182,000	$320	$2
> 20 kW commercial	129,000	$700	$2
TOTAL	4,540,000	N/A	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 fifty 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 fifty percent of the new AMI meters, and we will need to procure new lock pins for the other fifty 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.[13] In those cases, we will need to procure and install new AMI meters at these meter sites. Table 3-7 illustrates the meter type and expected volumes associated with replacing these failed meters.

Table 3-7
Meter Failures - Out of Warranty Only
(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

[13] *See* Volume 2, Section III concerning how this failure rate was calculated.

2021 timeframe due to customer growth. Table 3-8 shows the expected meter type and volumes associated with these new meter sets.

Table 3-8 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 new 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)

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

In order to support the aggressive deployment schedule discussed in Section II above, 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 twenty-five residential meters per day or eighteen commercial/industrial meters per day.[14] The cost of additional personnel to perform these installations is estimated to be $55.0 million over the 2006 to 2010 timeframe.

(ii) 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

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[14] 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 twenty residential meters per day and five commercial/industrial meters per day.

schedule required by the Ruling, we will rely on both full-time resources and contract resources. Beginning in 2006, we will dedicate eighty-seven 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 thirteen and thirty 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.

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

(f) <u>Meter Installation Tracking Systems (MS-6)</u>

As discussed in Section III of Volume 2, we expect that 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 just under 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 preliminary 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 preliminary 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 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 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 II 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% 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.[15] 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 fifteen additional employees to handle these activities at an estimated cost of $5.2 million over the 2006 to 2010 timeframe.

A critical assumption in our supply chain management analysis is that we will be utilizing RFID technology to facilitate the meter deployment processes. While this technology is being used in various industries, it is a new technology for us. Given the scale of the AMI deployment, we will engage consultants with experience in this technology to assist in the

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

development of RFID implementation and deployment plans. We estimate a cost of $0.66 million in 2006 for these activities. Our estimate is based on cost information received from a potential vendor of these services.

(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 ninety-five 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.

(3) Operations and Maintenance

(a) 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 2.8 full time employees (FTEs) in 2006, increasing to 28.9 FTEs in 2007, and then decreasing to 15.5 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% meter readers and 75% FSRs. In 2010, all 32 lower level supervisors are reduced in MS-1. Our personnel estimates are based upon a replacement rate of twenty-five residential meters per day and eighteen commercial/industrial meters per day.

Throughout the AMI full deployment, we expect 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 to identify possible theft situations, we expect to increase our current investigator staff from sixteen to thirty-two 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 ten-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 $0.93 million over the 2006 to 2021 timeframe.

(b) 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 fifty-six 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.

(c) 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.

b) Communications System

(1) Start-up

(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, ninety-six 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 eighty-five FTEs needed to maintain the communications network (these personnel costs are further described in cost category I-15). 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 to retrieve and process 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 II 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 $0.20 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 $1.82 million in project management and business analyst support labor costs for these activities over the 2006 to 2008 timeframe.

(2) Installation Costs

(a) 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 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 twenty 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.

(b) Pole Replacement (C-7)

We do not forecast that there will be any pole replacements required to support full deployment and thus we do not estimate any costs for this cost code.

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

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

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

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

(e) 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 radio frequency 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 ninety-six 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.[16] Overall, the estimated costs for the network communication equipment are $13.7 million.

Table 3-9 describes the annual deployment volumes associated with the communication infrastructure.

Table 3-9
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

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

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.

(f) WAN/LAN Training (C-11)

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

(3) Operation and Maintenance Costs

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

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

(b) 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.

(c) 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.

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

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

c) **Information Technology and Application**

(1) **Start-up and Design**

(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.

(2) **Installation**

(a) **Computer System Set-up (I-2)**

The 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 67 servers and 1,680 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.

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 $12.3 million.

(b) Data Center Facilities (I-3)

We do not forecast any incremental costs for this cost code because no new data center facilities are required for the full AMI deployment.

(c) 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 $25,000.

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

The full AMI deployment will require us to automate the procurement processes in our Meter Supply Chain System. The preliminary 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.[17]

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 $11.6 million over the 2006 to 2021 timeframe.

(e) Records (I-6)

We expect that new applications will be developed and existing applications will be enhanced to support automating the

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

meter change workflow and meter read conversion processes to accommodate the meter change volumes. 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.

(f) 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 at approximately $12,000.

(3) Operation and Maintenance

(a) Maintain Existing Hardware/Software that Translates 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 the system requirements are identified, these organizations will also 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 $20,500.

(b) Process Bill Determinant Data (I-9)

As usage data is collected and processed, we expect that additional customer service representatives will be needed to manually process accounts that the system is unable to process due to usage validation failures. For this cost code, we estimate approximately $7.1 million including the cost for 7.2 FTEs in 2006, increasing to 18.3 FTEs in 2008, then decreasing to a steady state of 5.3 FTEs from 2012 to 2021.

In terms of our IT systems, we will also need to dedicate resources to define 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 2006. We estimate the cost for these activities at $51,700.

(c) 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.

(d) 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, a judgment call is often required to estimate usage. Of the total meter failures, we estimate that fifty 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 6.4 FTEs in 2006, peaking at 16.5 FTEs in 2007, and tapering off to 4.3 FTEs by 2011. The estimated cost of $5.2 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 ten 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 $62,500.

(e) <u>License/O&M Software Fees (I-12)</u>

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.

(f) <u>Ongoing Data Storage/Handling (I-13)</u>

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

(g) <u>Ongoing IT Systems (I-14)</u>

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 $9.9 million during the 2006 to 2021 timeframe.

(h) 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 eighty-five 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 twenty 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.

(i) 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 preliminary analysis, a hardware refresh would occur in 2011 and again in 2016. As discussed in Section III of Volume 2, 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 $18.2 million.

d) Customer Service Systems

This section describes the Customer Services Systems related cost codes utilized in assigning costs for the "operational only" full AMI deployment scenario. Call Center, Meter Order Processing, Customer Communications and a portion of Billing-related costs are included in this cost category.[18] 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.

(1) Start-up and Design (None per ACR)

Appendix A of the 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

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[18] The majority of our billing system installation and operating costs are included in the Information Technology section (Section 1.(c) above) because cost codes I-9 and I-11 better described the billing related functions of "validating and creating billing determinate data" and "Exception Processing."

proposal specifications. These costs are included under cost codes C-1, C-5, I-1, and M-2.

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

This section describes 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.

(a) 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. 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 cost $14.8 million through 2021.

We anticipate a need for additional Billing 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.

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

We expect impacts on our Call Centers to be minimal for the operational-only full deployment case. We expect that a relatively small volume of calls will result from mass market media messages introducing the change to the affected customers. We also expect a very low response rate of one half of one percent of customers impacted in the deployment year who will call us 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 will occur as a result of the initial "meter change letter" that will be sent to all affected customers during implementation. 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 three percent and four percent estimates are based on our experience with other communications in which a service visit is required. In total, call volume is expected to increase during the installation phase and is expected to peak at approximately 52,000 additional calls per year in 2009, dropping to zero by 2011. This would require the addition of slightly more than four FTEs during the peak installation stage resulting in a total cost of $800,000 over the full duration of the analysis period.

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.

(c) 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 ($22,000) we have not identified any other incremental implementation costs related to OMS for this cost code.

(d) Process Meter Changes for New Meter Installations 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.

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

Only cost code CU-5 has a potential cost impact in this operational-only scenario. Even though there would be no new rates introduced under this operational-only scenario, we expect some 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.

This results in a total cost of $280,000 through 2021 in cost code CU-5. 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 those two cost codes. Cost code CU-8, CU-9 and CU-10 have to do with rate changes, interval data and customer communications. These three cost codes are not applicable within this operational-only scenario; they will be described in Scenario 3.

e) <u>Management and Miscellaneous Other Costs</u>

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.

(1) <u>Management and Miscellaneous Start-up and Design Costs (M-1 and M-2)</u>

(a) <u>Buyout of Existing Itron Contract for Automatic Meter Reading (M-1)</u>

In 1999 and 2000, SCE installed and implemented a large AMR program. This program included 350,000 meters equipped with electronic ERTs which provided 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 ten-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 eleven-year contract are considered to be "sunk cost." 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.

For the full deployment scenarios, 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, which was discussed earlier in this volume.

(2) Management and Miscellaneous Installation Costs [M-3 through M-11]

(a) Customers' Access to Usage Information (M-3)

Because this scenario is "Operational-Only" we will not be collecting interval data and we have not included any costs related to increased support of customer requests for more detailed usage information.

(b) 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 employees and keeping them informed and up-to-date on the implementation of AMI and its related systems.

(c) 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 the full AMI deployment scenario, 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 3-10 summarizes our estimated training costs related to implementation of the Operational-Only full deployment case.

Table 3-10 Training Costs by Cost Code (Full Deployment Costs in 2004 P V $)	
Cost Code	**Costs through 2021**
M-5 (Systems and Rate Structures)	$0.8 million
M-10 (Call Center, Meter Readers, Meter Techs.)	$1.4 million
MS-11 (Meter Installers, Handlers, Shippers)	$5.8 million
Total	$8.0 million

(d) Meter Reader Reroute Administration (M-6)

The cost of recycling and rerouting meter reading for the ten 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.

(e) 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 eighteen external support (contract) personnel in the initial year, dropping down to twelve 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.

In addition, each of the operating organizations has included the cost of their internal project management responsibilities in this cost code. In total, we expect overall project management costs to be approximately $29.3 million through 2021.

(f) <u>Recruiting of Incremental Workers (M-8)</u>

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.

(g) <u>Supervision of Contracts and Technology Personnel Assigned to Hardware and Systems Development (M-9)</u>

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

(h) <u>Training for Other Traditional Classifications (M-10)</u>

As described in Subsection (c) and Table 3-10 above, the training costs included in this cost code are expected to be $1.4 million.

(i) Work Management Tools (M-11)

Our Business As Usual operations discussed earlier in Volume 2 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.

(3) Operation and Maintenance [M-12 through M-14]

Capital and financing costs (M-12) are included in the NPV calculations at SCE's long-term weighted average cost of capital. Alternative methods of financing are discussed in the outsourcing scenarios (Scenarios 2 and 15). There is no change in the cost associated with mid and off-peak loads (M-13) under this scenario. Customer acquisition and marketing costs (M-14) will be discussed in the Demand Response scenarios and do not apply to the Operational-Only scenario.

2. Benefits

Table 3-11 summarizes the total estimated benefits we expect will result from the full deployment of AMI in the operational-only case.

Table 3-11 Summary of Benefits for Scenario 1 (2004 Pre-Tax Present Value Dollars)	
Benefit Categories	**Total**
Systems Operations Benefits	$304.1 million
Customer Service Benefits	5.4 million
Management and Other Benefits	121.1 million
Demand Response Benefits	-0-
TOTAL:	$430.6 million

The following sections will describe only those benefit codes that were actually used in this preliminary analysis. Appendix A to this Volume contains a discussion of all benefit codes identified in the Ruling, whether we actually included them in this analysis or not.

a) System Operations Benefits

In this section we will address the potential "system operations benefits" expected to result from full deployment of AMI to approximately 4.8 million SCE customers. Appendix A of the ACR identified 13 such potential benefits that may occur. In our initial review of these potential benefits, for the operational only scenario we have been able to quantify $304.1 million in savings, coming from only three of the 13 benefit code areas. We 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 ACR are either already being experienced by SCE or have associated costs that more than offset the anticipated savings. One benefit code (SB-9) applies only to the Demand response scenarios (Scenarios 3 through 8).

(1) 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 eighty management and support personnel, eighty percent of which would be eliminated with full deployment of AMI. As described in Volume 2, full deployment of AMI will result in our ability to automatically read ninety percent of all our meters. The remaining ten percent, or approximately 470,000 meters, will continue to be read monthly by approximately 109 meter readers.[19] In addition, we expect to eliminate sixteen of the existing meter reader supervisor positions with full deployment of AMI.[20]

The reduction of eighty 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 thirty-five to forty 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 eighteen months after AMI installations begin) and continue throughout the deployment years. Severance of thirty-two 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 in cost code MS-1. Additional savings will result from the

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[19] 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% of meters.

[20] These sixteen 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.

decommissioning of eighty-percent of our hand-held meter reading devices. This savings is reflected in benefit code MB-1.

(2) 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).

(3) Reduction in Energy Theft, Identifying Broken Meters, Wrong Multipliers, and Metered Accounts not Being Billed (SB-3)

No savings have been included (see Appendix A).

(4) 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 3-12 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 $3.5 million through 2021.

Table 3-12
Reduced Phone Calls – Full Deployment

Year	2006	2007	2008	2009	2010	2011
Reduced Calls	2,820	8,445	14,089	19,753	23,626	23,626

(5) Elimination of Rate Design Constraints Due to Meter Programming Limitations (SB-5)

No savings have been included (see Appendix A).

(6) Outage Management System (OMS) Benefits (SB-6)

No savings have been included (see Appendix A).

(7) Better Meter Functionality/Equipment Modernization (SB-7)

No savings have been included (see Appendix A).

(8) Remote Service Connect/Disconnect (SB-8)

No savings have been included (see Appendix A).

(9) Improved Meter Accuracy and More Timely Load Information (SB-9)

Savings have been included in demand response scenarios 3 through 8 (see Appendix A).

(10) Distribution Planning and Design (SB-10)

No savings have been included (see Appendix A).

(11) Reduction in Unaccounted for Energy (UFE) (SB-11)

No savings have been included (see Appendix A).

(12) Self-Generation Monitoring (SB-12)

No savings have been included (see Appendix A).

(13) Reduction in the Amount of Time Required to Implement New Rates or Load Management Programs (SB-13)

No savings have been included (see Appendix A).

b) Customer Service Benefits

The ACR identified thirteen customer service benefits, most of which relate to billing and demand-side management, and most would require the availability of interval load data, which does not apply to our operational-only scenario (Scenario 1). Our review of these potential areas of benefit resulted in anticipated savings in the operational-only scenario from only one of the thirteen areas of benefit for a total savings of approximately $5.2 million. This section will address our review and conclusions related to only those potential Customer Service Benefits that were actually used in our revised preliminary analysis. Appendix A of this volume discusses all thirteen potential customer service benefit codes, whether we used them or not.

(1) 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 $5.2 million over the duration of the analysis period.

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

(2) Early Detection of Meter Failures and Distribution Line Stresses Can Reduce Outages and Improve Customer Service (CB-2)

No savings have been included (see Appendix A).

(3) Additional Opportunity to Inspect Panel, Reattachment of Unsecured Meter Boxes, Identify Any Unsafe Conditions (CB-3)

No savings have been included (see Appendix A).

(4) Improves Billing Accuracy – Reduced Estimated Reads / Estimated Billing – Reduced Exception Billing Processing (CB-4)

Same as CB-1 above.

(5) Customer Energy Profiles for EE / DR Targeting (marketing) (CB-5)

No savings have been included (see Appendix A).

(6) Customer Rate Choice / Customer Rate Options (CB-6)

No savings have been included (see Appendix A).

(7) Customized Billing Date (CB-7)

No savings have been included (see Appendix A).

(8) Energy Information to Customer Can Assist in Managing Loads (CB-8)

See demand response Scenarios 3 through 8 and Appendix A).

(9) Enhanced Billing Options Could Be a Source of Revenue and Increased Customer Satisfaction (CB-9)

No savings have been included (see Appendix A).

(10) Load Survey – AMI Systems Allow Utilities to Perform Load Surveys Remotely and No Longer Require Recruitment and Site Visits (CB-10)

No savings have been included for Scenario 1, see Scenario 3 discussion and Appendix A.

(11) <u>On-line Bill Presentment With Hourly Data / More Timely and Accurate Information About Electricity / Info. Access (CB-11)</u>

See discussion under benefit code CB-8 in Scenarios 3 through 8.

(12) <u>Lower Customer Bills (CB-12)</u>

See discussion under demand response Scenarios 3.

(13) <u>Value to Customers of More Timely and Accurate Bills (CB-13)</u>

See discussion under benefit code CB-1 above and CB-12 in Appendix A.

c) <u>Management and Other Benefits</u>

Only two of the ten potential "Management and Other" benefit codes identified in the Ruling were actually used in SCE's revised preliminary analysis. The following sections describe our review of each of the potential Management and Other benefit codes.

(1) <u>Reduced Equipment and Equipment Maintenance Costs (Software Maintenance And System Support, Handheld Reading Devices, Uniforms, *etc.*) (MB-1)</u>

In the full deployment scenarios, we expect to reduce costs by approximately $2.9 million over the duration of the analysis period by decommissioning eighty 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.

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

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

(3) Reduced Battery Replacement / Calendar Resets / Meter Programming (MB-3)

No savings have been included (see Appendix A).

(4) 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 (Vol. 2, Section 2(B)(3)(c)) 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 the full deployment scenarios, this avoided cost is $118.2 million over the duration of the analysis period.

(5) 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. Full AMI deployment could result in further savings, as most of our summary billed service accounts' meters become automated.

The amount of savings resulting from this one-time improvement in cash flow is a complex analytical question that remains unanswered at the time this revised preliminary analysis is being completed. We expect to be able to include some savings under this benefit code in our March 2005 filing.

(6) 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 (below 25 watts) than do existing electromagnetic meters. Most electromagnetic meter discs sit "idle" when less than twenty to twenty-five 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 twenty-five 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 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 our full deployment scenario, this would add four megawatts of load twenty-four hours a day, 365 days per year. This would add over thirty-five 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 thirty to sixty 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.

(7) Possible New Revenue Source / New Business Ventures / New Products and Services / Web Based Interval and Power-quality Data (MB-7)

No savings are included. See discussion under benefit code CB-9 in Appendix A.

(8) May Facilitate Ability To Obtain GPS Reads During Meter Deployment – Improving Franchise and Utility Tax Processes (MB-8)

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.

(9) Tariff Planning – More Flexibility of Rate Contacts & Options Within Standard Customer Rate Classes / Dynamic Tariffs (MB-9)

See discussion under benefit codes SB-5, SB-13 and CB-6 in Appendix A.

(10) 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.

3. Uncertainty and Risk Analysis

As discussed in Volume 2 and in accordance with Attachment A of the Ruling, we performed a risk assessment of the operational costs and benefits for each full deployment scenario that could result from uncertainty or lack of data. The risk analysis we performed for this scenario is based on the specific cost and benefit data discussed in the sections above.

For analytical purposes, this operational risk assessment focuses on those cost and benefit codes that have estimates (in cumulative nominal dollars (i.e. 2006-2021) of $5 million or greater. Once the appropriate cost and benefit codes were identified, we developed the most likely high and most likely low ranges for each of the cost and benefit cost categories. Consistent with the Ruling, we then applied a Monte Carlo statistical approach to create a probabilistic range around our estimate. The results allowed us to determine the confidence levels of our estimates as well as a contingency value at a ninety percent confidence.

For Scenario 1, the total present value cost estimate for full AMI deployment is $902 million. The top five cost codes in Scenario 1 represent over sixty percent of the total cost for this scenario. The cost range for each of the five and the primary driver is highlighted. The most significant cost code (MS-3) in Scenario 4 is estimated at over $400 million and involves meter and meter-related communications equipment obtained from a single vendor. We estimated a range for this cost code to be: plus twenty percent and minus five percent. 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 twenty 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. Under this full deployment scenario our Billing organization estimate may vary in a range of plus twenty percent to minus fifteen percent depending on the number of exceptions processed. The meter and field communication installation costs may vary by as much as plus fifteen percent to minus twenty percent based on installation productivity. Our information technology computing systems lifecycle costs have a range of plus or minus forty percent due to the uncertainty of the data processing and storage required. Our software development costs ranged plus forty percent to minus fifty percent based on the uncertainty of the final design.

The primary operational benefits relate to the reduction in meter readers and result in aggregate 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 ninety percent of the meters. The other identified operational savings were less than the $5 million threshold we used for analytical purposes. As a result, we did not include any operational savings in the statistical analysis.

Using the cost ranges estimated above, the application of the Monte Carlo statistical analysis of costs resulted in a range of $874 million to $1.0 billion around the estimated cost of $902 million for this scenario. The statistical analysis indicates that our cost estimate has about a thirteen percent confidence. This means that the project has an eighty-seven percent chance of overrunning. Our preliminary cost estimates do not include contingency. However, based on our analysis, we should consider a contingency of approximately $64 million in our business case to reduce the risk of overrun. This contingency amount is the difference between our cost estimate and the value at the ninety percent confidence level.

4. Net Present Value Analysis

Our net present value analysis is summarized in Table 3-13.

Table 3-13 Summary of Cost/Benefit Analysis for Scenario 1 ($Millions)			
Costs	**Benefits**	**Pre-tax PV**	**NPV of Rev. Req.**
$901.9	$430.6	($471.3)	($918.1)

Costs and benefits for each business case scenario were estimated by the appropriate business units using current (2004) dollars for all non-labor costs, and job titles and estimated 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[21] using SCE's long-term Weighted Average Cost of Capital (10.50 percent). Cost categories from the Ruling[22] 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 Ruling's Cost Categories. As shown in Table 3-13 above, this scenario results in a negative Revenue Requirement Present Value of $918.1 million and does not support the implementation of full AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the Scenario 1 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.

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21 Ruling, p. 12.

22 Ruling, Appendix A.

B. Scenario 2: Operational Only - Outsourced

1. Overview of SCE's Approach to Outsourcing Analysis

The Ruling requires a full deployment scenario and directs the utilities to include the costs and benefits of outsourcing certain functions, presumably so the Commission can compare whether there are cost savings from outsourcing beyond what it would cost for the utility to perform these tasks. We support this analysis in that it is important to do a thorough review of the cost of all options. Inclusion of this outsourcing scenario also provides a reasonableness check on the cost estimates presented in the previous section for SCE-implemented full deployment of the Operational-Only scenario (Scenario 1).

As discussed in greater detail below, SCE supports outsourcing in certain functions where it makes sense and does not negatively impact our other operations or customers. Indeed, we currently outsource several areas of our normal operations where it makes economic and business sense to do so, including a portion of phone center calls, payment services and a sizeable portion of software development. Similarly, there are a number of areas where it does not make sense to outsource, either for operational efficiency, customer confidentiality, or financial reasons. For this reason, the "post-meter reading" Billing and Call Center functions were excluded from the outsourcing estimates and their AMI related incremental costs were added back in for purposes of comparison to the base-case and to the other scenarios.

In preparing this preliminary analysis, SCE has focused its outsourcing analysis on integrated solution companies that have legitimate and sufficient experience in their respective industries and the financial wherewithal to fulfill their contractual obligations. As discussed in this volume, the costs of deploying AMI are significant. Given the high stakes and detailed planning involved in such an enormous undertaking as deploying nearly 5 million meters in five years, we would require that an outsourcer be able to fulfill its contractual obligations or be able to pay stiff penalties. Our customers and the AMI project would be impacted negatively if the outsourcer's only option was to file for bankruptcy protection because it could not deliver on its contractual terms. Consequently, for this preliminary analysis, SCE has focused on potential outsourcers of a certain caliber that could sustain the uncertainties of an untested full deployment of new technology and has not considered the possibility of outsourcing to a possible "one-transaction" company whose main source of business/profit/credit would be from its AMI contract with SCE.

2. Overview of Results of Outsourcing Analysis

Our preliminary analysis indicated that potential integrated solution providers exist that have the corporate presence and capability to deliver the huge scope and scale contemplated for full deployment and would also be interested in responding to a formal bid process. Each of the integrated solution providers that participated in our preliminary analysis indicated that they would partner with multiple organizations to deliver the complete solution (*e.g.,* meter providers, software providers, communications providers, *etc.*). The integrated solution providers responded with complete outsourcing solutions that included all inherent components (*e.g.,* all related services, service levels, performance reporting, compliance, treatment of staff, governance considerations, technology, applications, *etc.*).

Due to the unique nature and scope of this undertaking, AMI by its very nature does not lend itself to taking advantage of many of the traditional outsourcing value propositions such as leveraging of shared resources, improved purchasing power, and faster implementation. AMI does not present the same degree of leverage that the more traditional outsourced functions offer. The nature of the work and the uniqueness of the customer base limit the opportunities to build highly leveraged and large scale service delivery models. We would be one of the first organizations to attempt outsourcing AMI on such a large scale (and the preliminary analysis indicates that for most service providers the scale would be greater than any other current customer AMI initiative). Being first may represent a risk profile greater than can be effectively absorbed.

The preliminary analysis does not indicate that there was a potential for significant economic value and concludes the outsourcing solution would be more expensive than an internal SCE solution. Table 3-14 below summarizes the results of the three most viable outsource cost estimates compared to SCE's cost estimates for the same full-deployment scenario.

Table 3-14 Summary of Financial Analysis of Outsourcing Scenario					
($000)					
	Service Provider				
Description	**A**	**B**	**C**	**Service Provider Average**	**SCE**
Installation Total	$ 833,526	$ 872,172	$2,517,835	$1,407,844	$1,130,000
O&M Total	$3,292,978	$2,377,223	$1,164,315	$2,278,172	$2,196,161
Retained Functions	$ 532,593	$ 523,822	$ 528,150	$ 528,189	
Total Costs	**$4,659,098**	**$3,773,217**	**$4,210,299**	**$4,214,205**	**$3,326,161**
All costs in nominal dollars adjusted for inflation					

3. Economic Assessment

Our preliminary economic assessment indicates that the savings opportunity associated with traditional outsourcing undertakings (such as IT, Finance, or HR) does not exist for outsourcing of AMI. The total cost to outsource the major elements of the full deployment scenario would be higher than the equivalent cost if we did the work ourselves. For full AMI deployment, the total cost of outsourcing (based on an averaging of the most complete integrated solutions provider feedback) is estimated at $4.2 billion, whereas SCE's cost is estimated at $3.3 billion (both in nominal 2004 dollars) for services beyond those considered solely for AMI (the outsourcing costs estimated included core activities beyond the scope of the AMI business case scenarios). To ensure an effective comparison, both the outsourced scenario and the internal scenario were developed with all components included (*i.e.,* representing the end-to-end AMI solution including "back office" functions) and with a consistent inflation (escalation) factor applied to all scenarios.

4. Overview of Approach

In order to comply with the Ruling, we undertook an initiative to analyze the potential to outsource some or all of the components for the implementation of AMI including acquisition, installation, operation and maintenance. The outsourcing analysis followed the same basic assumptions as the other scenarios for a full system deployment of meters and communication infrastructure to support various dynamic pricing rates, running from 2006 to 2021 with a five-year roll out period. The outsourcing analysis included four major components as follows:

- Data Sources (meter acquisition and financing, meter installation, meter testing, operations and maintenance);
- Data Transmission (communications network build-out, network management);
- Data Collection (meter read data processing, preparation of billable data); and

- Data Usage (billing and settlement, internet communication, outage management).

The back-end component Data Usage (including preparation of billable data) was considered out of scope for outsourcing consideration. This determination was based on an assessment of current capability, current performance, cost effectiveness, integrated IT environment, sunk-investment, and customer relations.

a) The RFI Process

To gather information that could be used in analyzing outsourcing within the timeframe available, a high level data collection activity was undertaken which took the form of a modified RFI process, with iterative steps for data gathering/clarification or refinement. This process was completed over a timeline of approximately eight weeks. This process began with an evaluation of existing full service integrated solution providers that could potentially deliver the services that would be required in the outsourcing of AMI. The evaluation profile included the following:

- The provider had to be large enough in terms of sales, employees, and capitalization to be viable in an arrangement of the proposed magnitude;
- The provider had to have the capability to deliver an AMI solution;
- The provider had to have been delivering similar solutions or be a respected supplier of unique solutions;
- The provider had to be able to deliver the solution in a cost effective manner;
- The provider had to be able to show a low risk profile;
- The provider had to have the capability to respond in a very short one – two week timeframe; and

- The provider had to be willing to bid on the services, if the services were outsourced.

Given the rapid response timeframe, the expected heavy interaction with the providers, the volume of anticipated questions, and the need to provide reasonably well priced solutions, we decided that only five integrated solution providers and one major meter provider would be included in the analysis. Additional potential providers exist, but due to the very short response timeframe, we chose to focus on those that best fit the profile, have the most experience, and were able to respond quickly.

The providers were asked to prepare a preliminary solution adequate to meet the requirements of the full deployment and partial deployment scenarios. Their solutions were to be reasonably consistent with available technologies, and executable under the specified parameters. They were to include a price estimate, including a financial (pricing) model, delineating when (or how) the charges will actually be incurred.

Three of the five integrated solution providers (providers A, B, and C) supplied a complete response while one (provider D) provided only a verbal representation of the solution and a cost formula. The solution attributed to provider D was determined to be too high a level of detail to be included in the preliminary analysis. The meter provider (provider E) provided a solution that was an initial deployment solution (with some high-level data points regarding ongoing O&M). Based on our concerns that the meter provider may not be able to effectively respond to the end-to-end delivery requirements of the AMI project, the response received from the meter provider was not included in the overall financial assessment.

For purposes of this preliminary analysis, all information received from the outsourcing providers, whether in documents or verbal communications shall be consistently treated as defined by the Non-Disclosure Agreements (NDA) executed between the providers and SCE. Outsourcing integrated solutions providers participating in this process will have no specific data attributed to a specific named provider.

b) Comparative Analysis

A baseline was created of the current meter organizations (FSMRO, MSO, and TDBU) using 2004 budget information and recorded costs through July 2004. This baseline was used to assess the in-scope labor component and to determine our retained functions. For the sake of expediency, the financial data provided by the integrated solution providers was normalized through a series of verbal communications with each of the service providers. Because each service provider responded in a different fashion, it was necessary to make model (price) changes for each response. This process also identified retained costs for SCE that would be considered as part of the end-to-end AMI solution and used in the comparison. A financial model was constructed that contains the following:

- Summary level presentation of both scenarios comparing integrated solutions provider response to our internal equivalent;
- Detail models for each provider solution scenario (where it was possible to construct the financial analysis from the response provided);
- High level assumptions;
- Categorization of cost codes (to indicate outsource, retain, or both);
- Detail models for out of scope activities that are required for AMI implementation;

- Detail models for retained meter functions; and
- Table of escalation factors (used in all scenarios analyzed).

The financial information received from the providers is a high level assessment of the cost of providing the services, and must be classified as informational only. The accuracy and completeness of the financial information cannot be considered firm. Additional data gathering and analysis would be required to develop more reliable financial information (*e.g.,* through a formal procurement process such as an RFP).

5. Summary of "Outsourcing" Findings

Although outsourcing solutions are becoming increasingly sophisticated, deriving significant leverage in this defined AMI scope appears to represent a significant challenge. Our initial analysis indicates that outsourcing AMI does not provide enough of a value proposition to support the full scope and may introduce additional risk.

There were five integrated solution providers that participated. Each provided varying degrees of completeness and each had somewhat different views of how the overall AMI outsourced services would be provided. However, in the preliminary analysis each has been normalized to allow a similar "apples-to-apples" comparison. Based on the financial comparisons, the scope of services does not provide the traditional outsourcing value of reduced expense. The scope of AMI does not provide the typical services where outsourcing can leverage resources and provide lower costs. Outsourcing of AMI does not present the opportunity to consolidate the labor force, leverage existing services, or purchase products at significantly reduced rates.

a) Installation and Start-up

AMI deployment is a complex project and as such, every facet has significant risk associated with it. The financing of the meter assets and associated hardware components appears to have lower cost through SCE's cost of capital or financing rate. All of the integrated solution providers proposed that SCE should finance the meters, given that SCE's cost of capital appears lower than the providers' rates.

In all cases, the integrated solution providers included a partnership with a meter manufacturer as part of their solution. Again in all cases, the integrated solution providers intended to complete the installations with contract labor. This use of contract labor would need further investigation regarding any additional costs that would be required as a result of potential labor union issues.

Meter testing assumptions varied by integrated solutions provider. The testing rate would need to be adjusted to meet the required service. This has potential pricing impact, but cannot be estimated until the exact meter manufacturer is chosen and a commitment to a specific defect level is achieved.

The initial deployment requires an inventory and distribution system that can handle approximately five million meters. Ongoing support of the infrastructure requires access by the provider into SCE's customer information system for customer data. SCE would be required to perform the majority of the estimated "back-office" IT application upgrades (*e.g.,* billing, contact center, *etc.*) regardless of the decision on outsourcing. The exact cost of the interfaces has not been estimated, but the view is that with advanced technology, there will be some cost to move data from the provider to SCE and visa versa.

The assessment of our preliminary outsourcing analysis indicates that from a cost perspective, the utility implemented scenario would be less expensive. The outsourcing scenario also adds a governance cost into the total cost. Given these results, it does not appear that outsourcing provides any financial benefits superior to the utility-implemented business case scenario for start-up and implementation.

b) Operations & Maintenance

On-going operations and maintenance for the full-scope deployment scenario includes the O&M of the existing meters during the five-year deployment phase (with inherent ramp down with the AMI rollout) and O&M of the new meters during the deployment phase (with inherent ramp up with the AMI rollout) and beyond. The responses from the integrated solutions providers included all functions up to and including delivering valid meter data to the billing function (with validation limited to reasonableness).

Determination of the treatment and transition of staff to a service provider were dealt with only at a high level for this analysis. There are issues related to union participation, severance, attrition, and training that would have an impact on the ongoing O&M function and cost. The three integrated solution providers provided solution descriptions that, at a high level, appeared to meet the requirements. Additional analysis would be required to ensure work flows, hand offs and responsibilities, and systems needs were fully defined.

Given these results, it appears that utility-implemented O&M provides financial benefits superior to outsourcing.

c) Retained Responsibilities and Governance

Governance and relationship management costs were estimated at one percent of the service provider estimated fee. This cost represents an oversight to ensure that the performed functions and products meet the requirements and continue to comply with all regulations. Retained responsibilities were identified for the meter functions (currently within our MSO, FSMRO, and TDBU Rurals organizations). These functions primarily would represent service delivery oversight, planning, design, customer relations, and other strategic functions. Finally, the miscellaneous implementation and operation responsibilities that were considered out of scope for our outsourcing analysis are identified as a retained function and cost.

C. Scenario 3: Operational Plus Demand Response - TOU Default With Opt-Out

Scenario 3 adds a Demand Response element to the full operational deployment of AMI. Not only do we include the costs associated with full operational deployment of AMI as presented in Scenario 1, but we have added the costs associated with the goal of placing and keeping a minimum of eighty percent of the AMI metered customers on TOU rates, with no more than twenty percent "opting-out" to their current rate or CPP-F rate. As was the case with Scenario 1, all costs and benefits included in the analysis of this scenario were estimated relative to the "Business As Usual" case. Table 3-15 summarizes the overall pre-tax costs and benefits of Scenario 3, and compares these costs and benefits to Scenario 1. Also shown is the after-tax NPV for these scenarios on a cash flow basis, and the present value of the revenue requirement over the sixteen-year analysis period.

Table 3-15 Scenario 3 Costs and Benefits Compared to Scenario 1 (2004 Present Value in Millions of Dollars)			
	Scenario 1	**Scenario 3**	**Difference**
Cost	$901.9	$1,212.3	$310.4
Benefits	$430.6	$571.3	$140.7
Pre-Tax PV	($471.3)	($641.0)	($169.7)
After-Tax NPV	($376.3)	($481.1)	($104.8)
NPV of Rev Req	($918.1)	($1,094.1)	($176.0)

Scenario 3 derives all the operational benefits previously discussed in Scenario 1 above plus approximately $133 million in demand response benefits resulting from energy and demand reduction savings attributable to TOU rates.[23] Another $7 million in benefits will result from the availability of interval load data which will provide improved energy supply forecasting techniques ($3 million), and vastly increase the availability of web based customer usage data ($4 million). These added benefits are offset, however, by added costs of more than $310 million, $192 million (or sixty-two percent) of which is due to a customer communications campaign that would be required in order to achieve eighty percent acceptance of the default rate and ten percent adoption of the CPP-F rate in this scenario. Another $79 million (or twenty-five percent) of the increase associated with going from the Operational-Only scenario (Scenario 1) to this demand response scenario is attributable to additional Information Technology costs. Billing costs increase by $53 million (or seventeen percent of the total increase).

[23] Demand response is generally discussed in Volume 2, Section III and will be discussed specifically with respect to this scenario in Section 5(d) below.

1. Overview of Cost Differences

a) Information Technology Costs

Additional Information Technology costs relate to the processes required to aggregate, validate and create billing-determinate data from interval consumption data being retrieved daily from nearly five million meters.

b) Billing Costs

Additional billing related costs result primarily from additional exception processing brought about by the more complex time-differentiated rate structures being introduced to the mass customer population. Customers being placed on more complex time-of-use rate structures, especially on an opt-out basis are expected to initiate more billing inquiries; in addition, the opt-out feature of the TOU default rate will inevitably result in mid-cycle rate changes. Failed usage validations, questionable usage (rate applicability) or meter "mis-match" problems will also add to the number of billing exceptions under this scenario. All of these exceptions require manual intervention on the part of the Billing Organization.

c) Customer Communications Costs

By far, the single largest cost impacts attributable to the demand response objectives of this scenario will result from the massive Customer Communications and Customer Education programs that will be needed in order to maintain an eighty percent rate of participation on the TOU default rate for this scenario. The anticipated mass market advertising and customer education campaigns that would be needed to meet these objectives are common to all of the full deployment demand response scenarios and were described previously in

Volume 2.[24] The Customer Communications programs related to this scenario are expected to add approximately $192 million in 2004 present value dollars to the project.

The costs associated with the addition of Demand Response options under the full deployment will differ based on the scenario, but the basic structure and approach to the media and information delivery campaign will be similar. The strategic approach of the campaign is to utilize an integrated mix of media designed to affect a long-term cultural and behavioral change, including raising awareness and educating customers about the program and its benefits as well as the behavioral changes required to comply with each specific demand response option; developing and implementing a strong and comprehensive acquisition effort to recruit customers and meet participation rate expectations; and developing and implementing a vigorous retention campaign to maintain the customer base over time. For this TOU “opt-out” scenario the following media will be employed:

- Mass Media: Television, radio, and print for education and awareness;
- Targeted/Ethnic Media: Local print, cable television, and strategic partnerships (ethnic business chamber promotion) including the use of in-language media for education and awareness; and
- Direct Communications: Bill inserts, direct mail, e-mail notification, voice mail notification, newsletters, face-to-face communication through the account management function for acquisition and retention.

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[24] *See* Volume 2, Section III.

Our Customer communications and outreach program is designed to reach 100 percent of our customers, and saturate the customer base with broad-based educational materials and information on customer-specific behavioral modifications.

d) <u>Call Center Costs</u>

We anticipate that the Call Center will be the central point of contact for customers wanting answers to their questions regarding the meter change process, rate changes, and “opt-out” procedures. For Scenario 3, we are estimating an increase in call volume of approximately 425,000 calls per year during the peak installation phase. This increased call volume will add a total of approximately $17.5 million to Call Center costs over the duration of the analysis period through 2021.

e) <u>Management and Miscellaneous Other</u>

The “Management and Other” cost categories make up $74 million of the $310 million in incremental cost differences between Scenario 1 and Scenario 3. The majority of this increase is attributable to $64 million of the $192 million Marketing and Customer Communications expenditures which were discussed earlier in this section. By definition, a significant proportion of customer communications and marketing costs fall into this cost category, thus causing customer communication and marketing costs to be split between two cost codes: CU-10 “Out-bound Communications (*e.g.*, mass media costs, print, radio, TV)”, and cost code M-14 “customer acquisition and marketing costs for new tariffs”. All the cost differences between Scenario 1 (Operational-Only) and Scenario 3 are described in the following sections.

2. Costs by Cost Code

Table 3-16 below summarizes the Scenario 1 versus. Scenario 3 costs by cost category.

Table 3-16
Summary of Costs for Scenario 3 vs. Scenario 1
(000s in 2004 Pre-Tax Present Value Dollars)

Cost Categories	Scenario 1	Scenario 3	Difference
Metering System Infrastructure	$667,983	$668,399	$416
Communications Infrastructure	39,500	41,974	2,474
Information Technology Infrastructure	127,696	206,003	78,307
Customer Service Systems	34,848	189,831	154,983
Management and Miscellaneous Other	31,851	106,086	74,235
TOTAL:	$901,878	$1,212,293	$310,415

a) Meter System Installation and Maintenance

(1) Start-up and design

Appendix A to the Ruling does not identify any cost categories for meter system start-up or design. As such, any start-up or design activities have been classified as an installation cost below.

(2) Installation and Maintenance [MS-1 through MS-11]

For this scenario, the descriptions of activities and the associated costs for these cost categories are identical to those described in Scenario 1.

(3) Operation and Maintenance [MS-12 through MS-14]

When comparing the cost estimates for Scenarios 1 and 3, the cost difference can be attributed to changes in the labor costs associated with our Billing organization, which are being charged to cost category MS-12. As with

Scenario 1, we anticipate that new issues will develop as a result of the implementation of new systems and the large number of meter changes. However, we anticipate that these issues will be more extensive given the introduction of new tariffed rate schedules to facilitate customers' demand response. We have estimated that additional personnel will be required in the initial phases of the implementation. As such, the labor costs for this area are estimated to increase by $0.42 million to $1.3 million over the 2006 to 2021 timeframe. The labor and non-labor costs of $43.1 million that are charged to MS-12 to support meter replacement and revenue protection activities are estimated to remain the same in this scenario as in Scenario 1. The descriptions of activities and the associated costs for cost categories MS-13 and MS-14 are the same as those described in Scenario 1.

b) Communications Infrastructure

(1) Start-up and design [C-1 through C-5]

In Scenario 3, the descriptions of activities and the associated costs for cost categories C-1, C-2, C-3, and C-4 are the same as those described in Scenario 1. However, there are changes in the costs related to cost code C-5. As discussed in Scenario 1, cost code C-5 captures the costs related to determining the appropriate IT application solutions to retrieve and process meter data. As discussed in further detail below, we will need to enhance additional applications in order to facilitate demand response capabilities in our systems. Given the additional applications that we are enhancing, we expect that the contractor costs associated with IT application solution design will increase from $0.20 million to $0.37 million.

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 applications that we are enhancing, we expect that the project management and business analyst support labor costs associated with these activities will 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 have estimated an increase from $1.8 million in Scenario 1 to $2.0 million in Scenario 3.

(2) Installation [C-6 through C-11]

In the installation area, there are two main differences between the Scenario 1 and Scenario 3 cost calculations. First, in Scenario 1, we did not have any incremental costs associated with cost code C-8. In Scenario 3, we will incur charges related to this cost category for Digital Signal Level 3 (DS3) costs. A DS3 is a high capacity telecommunication circuit. We plan to install two DS3s, one in our Rosemead facility and the other in our Irvine Operations Center 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 the equipment discussed in cost category C-10. Overall, the cost is estimated to be $1.9 million over the 2006 to 2021 timeframe.

Second, we also have differences in the costs associated with cost code C-10. In this scenario, we will continue to incur the $13.7 million in costs for the communications infrastructure hardware and equipment over the 2006 to 2010 timeframe that were discussed in Scenario 1. In addition, we will need to procure communication equipment that will link SCE's network to the DS3s discussed above. This equipment will be installed in 2006 and will need to be refreshed every five years. The cost associated with this additional equipment is $0.16 million over the 2006 to 2021 timeframe.

(3) Operation and Maintenance [C-12 through C-15]

In Scenario 3, the descriptions of activities and the associated costs for cost categories C-13, C-14 and C-15 are the same as those described in Scenario 1. The changes are related to cost code C-12. In Scenario 1, we did not have any charges associated with this cost code. However, in Scenario 3, cost code C-12 is used to capture the costs associated with various development tools licenses and fees. Non-labor costs of $49,700 are being charged to this cost code over the 2006 to 2007 timeframe.

c) Information Technology Infrastructure Costs

The information technology and application cost category captures the costs associated with applications and computer services. In addition to the costs incurred for the full deployment operational case, we will incur additional charges when demand response rates are introduced.

(1) Applications

In the Scenario 1 discussion, we described the various applications that would need to be developed and/or enhanced. For Scenario 3, these same applications would be required. In addition, enhancements would be required to our Service Billing, Usage Calculation, Wholesale Settlement, and SCE.com systems. The discussion that follows provides a brief description of enhancements to these systems.

(2) 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 tariffed 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. In Scenario 3, new tariffed rate 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.

(3) Usage Calculation

A core system functionality that will be needed to support AMI involves the processing of interval data. Currently, we have a fairly small-scale system, called the Customer Data Acquisition system, which calculates usage for existing customers with interval meter data. In this scenario, 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 full deployment of AMI. As demand, energy, and power factor data are collected from meters, it 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 to the Wholesale Settlement system for financial settlement.

(4) Wholesale Settlement

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 ISO 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 demand response tariffed rate schedules are introduced, the usage data received for wholesale settlement will be actual interval usage data, replacing the use of load profiles. As such, 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 nearly 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.

(5) SCE.com

Significant enhancements will need to be made to SCE.com in order to facilitate customers' 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 functionality for the user that will be developed, 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 fifteen-minute data from the previous day. Customers will have access to available interval data for up to thirteen months and will be able to view charts and graphs for comparing applicable data. Customers will also be able to access analytical tools to manage energy usage and control 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. During non-critical event peak hours, we expect a ten percent increase in access over what we are experiencing today. However, during critical event peak hours, we expect that increase to jump to 110 percent. This increase is based upon 9,000 users accessing SCE.com during any given critical peak hour and approximately twenty percent of those users accessing the system concurrently.

d) Information Technology Costs by Category

(1) Start-up and design [I-1]

For this scenario, the description of activities and the associated costs for this cost category are the same as described in Scenario 1.

(2) Installation [I-2 through I-7]

(a) 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 develop new applications and enhance existing applications. In Scenario 3, we are developing and enhancing additional applications to process the extensive volume of interval data that will be collected from meters to facilitate time differentiated billing. We are also enhancing SCE.com, our primary customer interface system. As compared to Scenario 1, in Scenario 3, we will need to procure additional hardware, storage, and operating software, including seventy additional processors and an additional 1,305 Gb storage, to supplement the computing infrastructure designed for Scenario 1. Given the data processing requirements of the demand response scenario, we will also need to increase the mainframe resources by 1,025 additional 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 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 3, 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.

In Scenario 1, the cost associated with our computing systems upgrades was estimated to be $12.3 million, which would be incurred in 2006. In Scenario 3, the costs are more extensive, estimated at $43.5 million over the 2006 to 2021 timeframe.

(b) <u>Data Center Facilities (I-3)</u>

In Scenario 1, we did not have any incremental costs associated with cost code 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.

(c) <u>Develop/Process Rates in CIS (I-4)</u>

As discussed in Scenario 1, a critical element of our IT application development efforts involves verifying that the new applications or enhancements do not adversely affect existing 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, unit and system testing. Since we are introducing more extensive application changes in Scenario 3, we will need to dedicate additional contractor resources to handle the testing activities. As such, we estimate the cost for these activities to increase from $25,000 to $222,000.

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

As described above, we will need to significantly enhance our Wholesale Settlement system. The costs associated with developing the system requirements and database schema for this system are captured in this cost code. In addition, with the introduction of additional applications in Scenario 3, we will need to engage additional contractor resources to handle interface design and verification activities during the 2006 to 2007 timeframe. These activities are charged to various cost codes, including I-7 and I-8, depending upon the interface. The overall cost estimates for this cost code will increase from $11.6 million to $12.3 million.

Our Customer Service organization will partner with our IT organization in developing system and business requirements for the revisions that need to happen to 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 that customers find the website easy to use. We have estimated $0.26 million in labor costs associated with these activities over the 2006 to 2010 timeframe.

(e) Records (I-6)

Additional applications will be developed and enhanced in Scenario 3, 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. Given these additional applications plus the extensive scope of the changes to them, we will need additional contractor resources to support these activities. We have estimated that the cost will increase from $0.53 million to $1.1 million in Scenario 3.

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

As detailed in the description for I-5, we will engage contractor resources to handle interface design and verification activities during 2006. In terms of the I-7 cost code, we estimate the cost for these activities will increase from $12,000 to $30,000.

(3) Operation and Maintenance [I-8 through I-16]

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

As detailed in the description for I-5, we will engage contractor resources to handle interface design and verification activities during 2006. In terms of the I-8 cost code, we estimate the cost for these activities will increase from $20,000 to $177,000.

(b) Process Bill Determinant Data (I-9)

In Scenario 3, 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 have 720 reads and 720 time stamps per month. With this volume of data, we expect that there will be additional usage validation failures than what we are projecting in Scenario 1. 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 relative to Scenario 1, our cost estimates have increased from $7.1 million to $17.9 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 is expected to increase from $52,000 to $505,000.

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

As with Scenario 1, there are no incremental contract administration costs and the costs associated with infrastructure database management are included in I-16.

(d) Exception Processing (I-11)

As discussed in Scenario 1, our Billing Organization will continue to incur costs related to manual processing of accounts that fail billing system validations. In Scenario 3, 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, we expect to dedicate additional personnel to handle this manual processing. Our cost estimates indicate a $1.3 million difference between the costs in Scenarios 1 and 3.

In support of our IT systems, we will need to dedicate additional personnel to defining and developing the process by which exceptions are handled. We estimate the cost for these activities will increase from $62,000 to $98,000.

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

The descriptions of activities and the associated costs for these cost categories are the same as those described in Scenario 1.

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

As with Scenario 1, the incremental costs associated with ongoing data storage and handling were charged to cost code I-16.

(g) Ongoing IT Systems (I-14)

As discussed in Scenario 1, cost code I-14 captures the costs related to the ongoing O&M for applications support, security administration, database administration support, maintenance and enhancement activities associated with the portfolio of applications that have been developed or enhanced to support AMI. In Scenario 3, we are introducing significant application enhancements, particularly those associated with the Usage Calculation system, in order to process the extensive volume of interval data. As such, we will need to dedicate additional contract and SCE resources to support our portfolio. We have estimated that the labor and non-labor costs to perform these activities will increase from $9.9 million in Scenario 1 to $13.5 million in this scenario.

(h) Operating Costs (I-15)

The descriptions of activities and the associated costs for these cost categories are the same as those described in Scenario 1.

(i) Server Replacements (I-16)

We expect to replace the computing systems hardware identified in cost code 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 code. Given that our computing systems are more extensive (as discussed in the description for cost code I-2) in this scenario than in Scenario 1, we will have more equipment subject to refresh in 2011 and 2016. As such, the costs for refreshing the computing systems and associated labor are estimated to increase from $18.1 million in Scenario 1 to $47.1 million in this scenario.

e) Customer Service Systems

(1) Start-up and design

Appendix A to the Ruling does not identify any cost categories for customer service systems start-up or design. As such, any start-up or design activities have been classified as an installation cost below.

(2) Installation [CU-1 through CU-4]

In the installation area, there is one significant difference between the Scenario 1 and Scenario 3 cost estimates. In Scenario 3, there will be additional charges related to cost category CU-2 due to increased call volume in our Customer Communications organization. We expect to experience the same call volume level for mass communications and meter change letters in Scenario 3 as we did in Scenario 1. However, with the introduction of time-differentiated rate schedules to facilitate customers' demand response, there will be additional customer communications that will ultimately lead to additional call volume. First, we will send customers information notifying them that their rate will be changed to a TOU 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 twenty-seven percent of customers call about opting out and seventy percent of those that call will actually choose to opt-out. Overall, for this cost code we are expecting to increase the call volume during the installation phase of the project, going from 50,000 per year in Scenario 1 to over 800,000 calls per year in Scenario 3. This results in a total cost increase of $13.6 million comparing Scenario 3 costs to Scenario 1 costs.

(3) Operation and Maintenance [CU-5 through CU-10]

(a) Additional Rate Analysis (CU-5)

As new rates are introduced in Scenario 3, we expect to experience an 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 $2.7 million in cost code CU-5.

(b) Customer Education of Rate Changes CU-8

In Scenario 3, 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 3, 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.

(c) Customer Support for Internet Based Usage Data Communication 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.

In Scenario 3, 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 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.

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

As discussed previously, the most significant cost difference in the operation and maintenance area between Scenarios 1 and 3 is related to the marketing costs, a portion of which are charged to cost category CU-10. The Customer Communications programs related to this scenario are expected to add a total of approximately $128 million in costs. 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.

f) Management and Miscellaneous Other

The Management and Miscellaneous cost categories make up $74 million of the $310 million in incremental cost differences between Scenario 1 and Scenario 3. The majority of this increase is attributable to the $64 million in Marketing and Customer Communications expenditures needed to retain 80% of the AMI metered customers on TOU rates, given that they will have the option of opting-out either to return to their otherwise applicable tiered rate or to move to an optional CPP rate. The $64 million in marketing costs assigned to this cost category is in addition to the $128 million described previously for this scenario in cost code CU-10. The remainder of the management and miscellaneous cost increases for Scenario 3 are described in the following sections.

(1) Start-up and design [M-1 through M-2]

These two cost codes relate to meter installations and were addressed in the Operational-only scenario. No additional costs would be incurred in this demand response scenario.

(2) Installation [M-3 through M-11]

Four of these management cost codes (M-6, M-8, M-9 and M-11) were described in Scenario 1 above with no incremental increases for the demand response scenarios.

(a) 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.

(b) Employee Communications and Change Management (M-4)

We estimated $104,000 in additional cost related to all demand response scenarios over the duration of the analysis period for Web-related costs associated with employee communications.

(c) Employee Training for New Systems and Rate Structures *etc.* (M-5)

Employee communication programs on the web will add $396,000 to this cost code for all demand response scenarios. This will supplement the Billing Organization and JST training described in Scenario 1 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.

(d) Project Management Costs and Overhead (M-7)

The Billing Organization, Call Center and IT combined will have approximately $5.5 million in management and overhead cost increases under this scenario versus Scenario 1. This is for indirect management and supervision activities related to the increases in personnel for the functions described previously in the Information Technology (I-1 through I-16) and Customer Services (CU-1 through CU-10) cost codes.

(e) Call Center Training Costs (M-10)

The Call Center would incur $780,000 in additional cost for specialized training to be able to respond to the large anticipated call volume brought about by the opt-out provisions of the TOU default rate. This is in addition to the "Customer Services" cost impacts discussed previously under cost codes CU-2, CU-8, and CU-9 above.

(3) Operation and Maintenance Costs (M-12 through M-15)

Our capital financing costs are included within the Meter Acquisition costs described previously, and we did not use the M-12 cost code to include any additional or alternative financing costs. Nor have we identified any cost for increased load during mid-peak and off-peak periods (M-13).

(a) **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 $192 million to be spent on customer acquisition and customer education programs that will be necessary to secure eighty percent of the AMI metered customers on TOU rates, and keep them there for the duration of the analysis period.

(b) **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 ninety 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 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 in the following section under benefit code SB-9.

3. <u>Benefits</u>

Estimated benefits for Scenario 1 and Scenario 3 are compared by benefit category in Table 3-17 below.

Table 3-17
Summary of Benefits for Scenario 3
(000s in 2004 Pre-Tax Present Value Dollars)

Benefit Categories	Scenario 1	Scenario 3	Difference
Systems Operations Benefits	$304,110	$307,333	$3,223
Customer Service Benefits	5,385	8,268	2,883
Management and Other Benefits	121,110	122,316	1,206
Demand Response Benefits		133,350	133,350
TOTAL:	$430,605	$571,267	$140,662

In addition to $133 million in demand response benefits described later in this section, we have recognized $1.2 million in equipment replacement benefits (MB-1), and an additional $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).

Our Energy Supply and Marketing Organization has estimated $3.2 million in reduced resource acquisition costs in cost code SB-9. This is the result of improved long- and short-term forecasting attributable to improved modeling and analytical techniques using AMI data.

To determine the DR-1 benefit, we employ a rigorous method of computing demand response from TDRs, as described in detail in Section III.B of Volume 2. We apply our respective TDRs for this scenario for the tariff participation as discussed above and illustrated in Volume 2 (our TDR rates are described in Volume 2, Section III.C, and Appendix B, by class). We also use price elasticity data by rate and rate period derived in the SPP, adjusted for our climate and air conditioning saturation by climate zone. We employ a computer simulation model to estimate the load reductions by rate and period for the duration of the scenario and compute a present value using our assumed discount rate.

Scenario 3 assumes that 80 percent of eligible customers are defaulted to TOU rates and those customers stay on that rate for the full duration of the business case. For the purposes of the analysis, SCE assumed that the customers opting out of the default would either switch back to their tiered rate or choose a CPP-F rate in equal proportions (10 percent each).

In the Ruling's required scenarios, we estimate the demand reduction from TDRs using customer enrollment assumptions provided by the ACR and customer response as was observed in the SPP experiment in summer 2003, except in scenarios involving opt-out tariff enrollments, where we make a Customer Behavior Adjustment to account for expected differences in customer behavior between customers involved in the pilot project and customers who default to a time differentiated rate in a mass market deployment.

For this scenario, we employ a Customer Behavior Adjustment to account for the fact that the SPP demand response results only represent load reductions for customers that affirmatively chose (or opted-in) to the TDR. Customers that default to the TDR who would not otherwise opt-in to the rate would have different demand response behavior as explained in Volume 2. We therefore modified the load impact results derived from the SPP and illustrate the effect for residential customers for Scenario 3 below.

Table 3-18 Residential Load Impact Adjustment for Scenario 3 Using SPP Results for Summer 2003				
	Percent of Eligible Customers Enrolled of Total Population	Percent of Customers on TOU	Factor of SPP Load Impact	Weighted Factor of SPP Load Impact
Willing (Opt-in) Participants	15.7	19.6	100 percent	0.196
Unwilling Participants	64.3	80.4	50 percent	0.402
Total	80	100		0.598

Thus, we apply a factor of 0.598 to the average customer load impact response per zone found in the SPP.

We then make an adjustment to determine the amount of load reduction we can expect to achieve at a ninety-five percent confidence interval using the variances found in the SPP model estimations. We treat that expected demand reduction as a "load modifier" and apply a distribution loss factor of 8.4 percent to that amount as an estimate of approximate losses between a generator and end use customer at peak times. We value those expected capacity and energy benefits in accordance with the capacity and energy assumptions provided in the ACR for DR-1 benefits.

Also, in all scenarios, since we reduce our expected load by the calculated demand reduction at peak, we apply system reliability benefits (capacity buffer/DR-2). The reduction in load from TDRs reduces the amount of capacity for which a reserve margin of fifteen percent would be procured. Therefore, system reliability (capacity buffer/DR-2) benefits were calculated as fifteen percent of TOU and CPP demand reductions only on CPP days. DR-2 benefits are additive to the DR-1 benefits calculated for each rate and scenario.

As described in Volume 2, Section III.B, we do not believe DR-3 or DR-4 benefits apply in any scenario.

The full deployment scenarios cover various Time-Differentiated Rate (TDR) approaches to the population equipped with AMI, as required in the ACR. Under full deployment of AMI, ninety percent of residential customers would be eligible for TDRs. Customer enrollment percentages per TDR are applied to the eligible population equipped with AMI. It is assumed that customers enrolled in any type of CPP rate will be fully aware of their rate mechanism and will be notified individually of CPP events.

The total benefit is shown in Table 3-19.

Table 3-19
TOU Default with Opt-out to CPP-F or Current (Scenario 3)

	No. of Meters (Customers)Year 2021	Percent of Eligible Meters	Present Value ($ millions)
Meters Eligible for TDRs	4,835,650		
Customers Enrolled on TOU	3,868,520	80	
Customers Enrolled on CPP-F/V	483,565	10	
Customers Enrolled on Current	483,565	10	
Total DR-1 Benefits			119
Total DR-2 Benefits			14
Total DR Benefits			133

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix B. For this scenario, the Value of Service loss is approximately $53.5 million (2004 present value dollars), reducing the total demand response benefit from $133 to $79.8million.

4. Uncertainty and Risk Analysis

For Scenario 3, the total present value cost estimate for full AMI deployment is $1.21 billion. We developed cost ranges as described in Section III.C.3 and applied a Monte Carlo statistical analysis of costs that resulted in a range of $1.172 billion to $1.324 billion for this scenario. The statistical analysis indicates that our cost estimate has a thirteen percent confidence. This means that the project has an eighty-seven percent chance of overrunning. Our preliminary cost estimates do not include contingency. However, based on our analysis, we should consider a contingency of approximately $67 million in our business case to reduce the risk of overrun. This contingency amount is the difference between our cost estimate and the value at the ninety percent confidence level.

Risks and uncertainties for the demand response are generally discussed in Volume 2, Sections III and IV. However, there are certain risks and uncertainties applicable to Scenario 3. First, opt out or default customer enrollment on TOU rates likely has the greatest chance of success of any TDR approach since it would be less "invasive" to customers than CPP and similar to peak pricing in other industries such as telephones. Thus, in our view, it is more likely that TOU would achieve significant and sustained customer participation. Since customers would not have to be notified of CPP events, they could remain less aware of their rate structure and a higher percentage of customers may remain on a TOU rate over time than if they had higher awareness, according to market research in SPP. However, an assumption of higher participation in TOU, (ninety percent rather than eighty percent), and less participation in CPP-F (five percent rather than ten percent) would yield lower demand reductions than Scenario 3 because the elasticity assumptions for CPP-F are more than double that of TOU.

SCE believes that the result for DR-1 benefits in this scenario could be less than estimated because the customers opting-out from TOU to a CPP-F rate would likely be those who benefit by making no adjustment in usage, therefore providing less demand response benefit for that rate group. This is because, for lack of better information, the demand response behavior of CPP-F customers in this scenario is assumed to be the same as the behavior of customers in the SPP experiment. In the SPP, it is unclear whether customers opted-in to the experiment where they were paid an incentive of $175 to participate. Customers on CPP-F rates apparently changed behavior but it is unknown whether this was due to the rate or the incentive payment.

If DR-1 benefits are smaller, the DR-2 benefits would decrease proportionately.

5. Net Present Value Analysis

Table 3-20 summarizes the overall pre-tax costs and benefits of Scenario 3. 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 sixteen-year analysis period.

Table 3-20
Summary of Cost/Benefit Analysis for Scenario 3 ($ Millions)

Costs	Benefits	Pre-tax Present Value	After-Tax NPV	Rev. Req. Present Value
$1,212.3	$571.3	($641.0)	($481.1)	($1,094.1)

As shown in Table 3-18 above, Scenario 3 analysis results in a negative Revenue Requirement present Value of $1,094.1 million and does not support the implementation of full AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the scenario 3 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.

D. Scenario 4: Operational Plus Demand Response - CPP-F/CPP-V Default with Opt-Out

Similar to Scenario 3 above, Scenario 4 assumes full deployment of AMI meters to ninety percent of all SCE customers. The only difference between Scenario 3 and Scenario 4 is that the default rate in this scenario is CPP-F for residential customers and CPP-V for C & I customers (TOU was the default rate for all customers in Scenario 3). The only cost difference between Scenario 3 and Scenario 4 is in the Marketing and Customer Communications programs, where we would expect to spend approximately $21.6 million more in cost code CU-10 for CPP event notification costs over the duration of the analysis period. This notification requirement is expected to add approximately $1 million to $3 million annually to the total program cost depending on the number of CPP events. For our purposes in this analysis, we have assumed fifteen CPP events per year. This is consistent with the number being used in the Statewide Pricing Pilot (SPP). There are no other assumed operational cost differences between this scenario and those presented earlier in the Scenario 3 analysis.

Table 3-21 summarizes the costs and benefits for Scenarios 3 and 4.

Table 3-21
Scenario 4 Costs and Benefits Compared to Scenario 3
(In Millions of 2004 Present Value Dollars)

	Scenario 3	Scenario 4	Difference
Cost	$1,212.3	$1,233.9	$21.6
Benefits	$571.3	$805.0	$233.7
Pre-Tax PV	($641.0)	($428.9)	$212.1

Scenario 4 derives all the operational benefits previously discussed in Scenario 3 above plus approximately $443.3 million in demand response benefits resulting from energy and demand reduction savings attributable to increased customer participation on CPP rates.

1. Costs

Table 3-22 below summarizes the costs by cost category for Scenario 4 versus Scenario 3.

Table 3-22
Summary of Costs for Scenario 4
(000s in 2004 Pre-Tax Present Value Dollars)

Cost Categories	Scenario 3	Scenario 4	Difference
Metering System Infrastructure	$668,399	$668,399	$-0-
Communications Infrastructure	41,974	41,974	-0-
Information Technology Infrastructure	206,003	206,003	-0-
Customer Service Systems	189,831	211,460	21,629
Management and Miscellaneous Other	106,086	106,086	-0-
TOTAL:	$1,212,293	$1,233,922	$21,629

Other than the $21.6 million additional cost related to notifying customers in advance of CPP events (cost code CU-10), all other Customer Communications and Marketing programs that will be needed to maintain an eighty percent rate of participation on the CPP default rates are the same as those described for Scenario 3. Proactive notification will be provided to those customers who subscribe to the "Envoy" service administered by SCE. The proactive notification consists of a single courtesy call via telephone, fax, page, or email that will be placed to the number/device ID provided by and maintained by the customer. The notification message content will include event date, time, and duration. If the customer selects to be notified via telephone, the event information will be conveyed through a pre-recorded thirty-second message. Customers will not be charged for this service but must initiate and maintain their enrollment in order to participate. Absent such customer designation of contact information, SCE will not proactively or individually notify other default CPP participants.

Costs related to CPP event notification were calculated directly as a function of the number of customers expected to participate on the CPP tariff over the duration of the analysis period. For Scenario 3 we estimated 450,000 to 500,000 sustained CPP participants; whereas, for Scenario 4 we estimated approximately four million participants.

2. Benefits

This scenario assumes that eighty percent of eligible customers are defaulted to CPP-F rates (residential) or CPP-V rates (commercial <200 kW) 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 default would either switch back to their tiered rate or choose a TOU rate in equal proportions.

Scenario 4 benefits are summarized below in Table 3-23. These benefits are the same as those described previously for Scenario 3, except the demand response benefits are estimated to increase by $234 million (going from $133 million in Scenario 3 to $367 million in Scenario 4). The reason for the much higher benefit is that customers on CPP rates demonstrated higher price elasticity on CPP rates than TOU. As previously noted, the SPP experiment did not find statistically significant price responsiveness for customers on TOU rates. Alternatively, the price elasticity for the TOU portion of the CPP rate on non-CPP days was used as a proxy. The price elasticity differences for CPP-F compared to TOU by climate zone and rate class are shown in Volume 2, Section III.

In the Ruling's required scenarios, we estimate the demand reduction from TDRs using customer enrollment assumptions provided by the ACR and customer response as was observed in the SPP experiment in summer 2003, except in scenarios involving opt-out tariff enrollments, where we make a Customer Behavior Adjustment to account for expected differences in customer behavior between customers involved in the pilot project and customers who default to a time differentiated rate in a mass market deployment.

For this scenario, we employ a Customer Behavior Adjustment to account for the fact that the SPP demand response results only represent load reductions for customers that affirmatively chose (or opt-in) the default rate. Customers that default to the TDR who would not otherwise opt-in to the rate would have different demand response behavior as explained in Volume 2. We therefore modified the load impact results derived from the SPP and illustrate the effect for residential customers for Scenario 3 below.

Table 3-23
Residential Load Impact Adjustment for Scenario 4
Using SPP Results for Summer 2003

	Percent of Eligible Customers Enrolled of Total Population	Percent of Customers on TOU	Factor of SPP Load Impact	Weighted Factor of SPP Load Impact
Willing (Opt-in) Participants	16.8	21	100 percent	0.21
Unwilling Participants	63.2	79	50 percent	0.395
Total	80	100		0.605

Thus, we apply a factor of 0.605 to the average customer load impact response per zone found in the SPP.

We then make an adjustment to determine the amount of load reduction we can expect to achieve at a ninety-five percent confidence interval using the variances found in the SPP model estimations. We treat that expected demand reduction as a “load modifier” and apply a distribution loss factor of 8.4 percent to that amount as an estimate of approximate losses between a generator and end use customer at peak times. We value those expected capacity and energy benefits in accordance with the capacity and energy assumptions provided in the ACR for DR-1 benefits.

Also, in all scenarios, since we reduce our expected load by the calculated demand reduction at peak, we apply system reliability benefits (capacity buffer/DR-2). The reduction in load from TDRs reduces the amount of capacity for which a reserve margin of fifteen percent would be procured. Therefore, system reliability (capacity buffer/DR-2) benefits were calculated as fifteen percent of TOU and CPP demand reductions only on CPP days. DR-2 benefits are additive to the DR-1 benefits calculated for each rate and scenario.

As described in Volume 2, Section III.B, we do not believe DR-3 or DR-4 benefits apply in any scenario.

Table 3-24
Summary of Benefits for Scenario 4 vs. Scenario 3
(000s in 2004 Pre-Tax Present Value Dollars)

Benefit Categories	Scenario 3	Scenario 4
Systems Operations Benefits	$307,333	$307,333
Customer Service Benefits	8,268	8,268
Management and Other Benefits	122,316	122,316
Demand Response Benefits	133,350	367,109
TOTAL:	$571,267	$805,027

The total benefit is estimated to be $805 million in present value as shown in Table 3-25.

Table 3-25 CPP-F/V Default with Opt-out to TOU or Current (Scenario 4)			
	No. of Meters (Customers) Year 2021	**Percent of Eligible Meters**	**Present Value ($ 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

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix B. 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.

3. Uncertainty and Risk Analysis

Scenario 4 costs and operational benefit risks and analysis results are essentially the same as described previously in Scenario 3.

We believe that this scenario is implausible for a number of reasons. First, we believe that it is unlikely that CPP rates would be imposed on the mass market without first testing customer acceptance of TOU rates over many years.

Next, we believe that even if default enrollment of CPP was implemented, it is highly unlikely that eighty percent of customers would adopt the CPP rate over the entire sixteen-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. 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. We provide an alternative analysis of this scenario using sustained participation rates of fifty percent for CPP in Scenario 10 below.

Another key but unlikely assumption is that all eighty percent of customers on CPP-F and V would respond over the sixteen-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. In Volume 2 of this filing, we described the above and other concerns and uncertainties associated with CPP rates as well as whether AB1-X would preclude a default implementation of CPP.

4. <u>Net Present Value Analysis</u>

Table 3-26 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 sixteen-year analysis period.

Table 3-26 Summary of Cost/Benefit Analysis for Scenario 4 ($Millions)				
Costs	Benefits	Pre-tax Present Value	After-Tax NPV	Rev. Req. Present Value
$1,233.9	$805.0	($428.9)	($355.0)	($882.2)

Scenario 4 analysis results in a negative Revenue Requirement Present Value of $882.2 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.

E. <u>Scenario 5 and Scenario 6: Operational Plus Demand Response - Current Tariff with Opt-in to CPP Pure (Scenario 5) and Opt-in to CPP-F and CPP-V (Scenario 6)</u>

These two scenarios are prescribed in Attachment A of the Ruling as two of the five tariff structures to be analyzed in the full deployment case.[25] Both our Scenario 5 and Scenario 6 analyses assume the existing tariff structures will remain as the "default" tariff and customers will have the option of a CPP tariff. The only difference between Scenario 5 and Scenario 6 is that Scenario 5 offers the "CPP-Pure" rate option to all rate classes,[26] and Scenario 6 offers the "CPP-F" rate option to residential customers and the "CPP-V" rate option to C&I customers. From an operational standpoint, SCE assumes no difference in costs between

[25] Ruling, Attachment A, p. 11.

[26] The "CPP-Pure" rate does not exist today. All current CPP rates fall back onto a TOU rate for non-critical peak periods. "CPP-Pure" would be a newly adopted rate schedule that would fall-back on the customer's OAT for non-critical peak periods.

Scenarios 5 and 6. The only difference between the scenarios is in the level of demand response benefits we would expect to receive between the two options.

For comparison purposes, we will describe the cost differences of these two scenarios relative to Scenario 4, which had CPP-F/V as the "default" tariff. Thus, the following incremental differences in costs and benefits reflect the savings we expect would result from making CPP "optional" rather than the "default" tariff. This difference significantly reduces the level of customer participation, thus reducing not only the cost, but the demand response we expect would result.

Table 3-27 compares the costs and benefits for Scenarios 5 and 6 to the costs and benefits we expect for Scenario 4 and Scenario 1.

Table 3-27
Comparison of Costs, Benefits, and NPV
for Scenarios 1, 4, 5 and 6
(Millions of 2004 Pre-Tax Present Value Dollars)

	Scenario 1 Operational Only	Scenario 4 OP + CPP Opt-out	Scenario 5 OP + CPP-Pure Opt-in	Scenario 6 OP + CPP-F/V Opt-in
Costs	$901.9	$1,233.9	$1,150.1	$1,150.1
Benefits	$430.6	$805.0	$605.7	$603.1
Pre-Tax PV	($471.3)	($428.9)	($544.4)	($547.0)

1. <u>Costs by Cost Code</u>

This section will describe the differences between the incremental costs by cost code for Scenario 4 verses the costs for Scenarios 5 and 6. As Table 3-28 shows, the costs for Scenarios 5 and 6 are identical.

Table 3-28 Summary of Costs for Scenarios 4, 5 and 6 (000s in 2004 Pre-Tax Present Value Dollars)				
Cost Categories	**Scenario 4**	**Scenario 5**	**Scenario 6**	**Difference (4 v. 5 & 6)**
Metering System Infrastructure	$668,399	$668,399	$668,399	-0-
Communications Infrastructure	41,974	41,974	41,974	-0-
Information Technology Infrastructure	206,003	197,189	197,189	$8,814
Customer Service Systems	211,460	180,806	180,806	30,654
Management and Miscellaneous Other	106,086	61,779	61,779	44,307
TOTAL:	$1,233,922	$1,150,147	$1,150,147	$83,775

a) Meter System Installation and Maintenance

For Scenarios 5 and 6, the costs are identical to those described in Scenario 4.

b) Communications Infrastructure

For Scenarios 5 and 6, the costs are identical to those described in Scenario 4.

c) Information Technology Infrastructure

In Scenarios 5 and 6, the cost differences relative to Scenario 4 are contained within two cost categories, I-9 and I-11. With the introduction of demand response rates, our Billing Organization will see an increase in the amount of usage data that is collected and processed. As discussed previously, we expect that there will be additional usage validation failures and billing validation failures in demand response scenarios than what we would see in operational-only scenarios. Additional customer service representatives are needed to manually process the accounts that the system is unable to process. The number of additional personnel that we need for this activity will vary between Scenarios 5 and 6 and Scenario 4. Our personnel estimates are driven by the number of customers on a rate requiring interval data. Since we anticipate a smaller number of customers will have rates requiring interval data in Scenarios 5 and 6, we anticipate that we will need fewer customer service representatives to handle this manual processing of accounts. For cost code I-9, we have decreased our cost estimate from $17.9 million in Scenario 4 to $11.9 million in Scenarios 5 and 6. For cost category I-11, our cost estimate decreases from $6.5 million in Scenario 4 to $3.7 million in Scenarios 5 and 6.

d) Customer Service Systems

Customer Service Systems costs are significantly lower for Scenarios 5 and 6 in two specific areas:

- Marketing and customer costs in cost code CU-10 will be $18.9 million lower for these scenarios than for Scenario 4. This is due to the expected smaller number of customer participants and the reduced call volume for proactive notification of CPP events to those customers who subscribe to the "Envoy" service administered by SCE.
- Call Center costs will be $9.4 million lower, due again to the lower number of active participants and lower anticipated call volume because there will be no "default" rate change notices and no "opt-out" provision under these scenarios. These costs are shown in cost code CU-2. Cost code CU-8 estimates for the Call Center are also lower for these two scenarios by $2.2 million. This is due to fewer calls expected

during critical peak pricing events, and resultant bill impacts.

e) Management and Miscellaneous Other Costs

The Management and Other cost categories are $44.3 million lower for these two scenarios due primarily to $40.7 million less required for "customer acquisition and marketing" costs in cost code M-14. Project Management costs (cost code M-7) are also expected to be lower in the Call Center and Billing Organization by $3.2 million over the duration of the analysis period. Call Center training costs (cost code M-10) will also be lower by $468,000, again due to the lower anticipated call volume and less need to train new employees.

2. Benefits

As shown in Table 3-29 the benefits by category for Scenarios 4, 5, and 6 are identical except for the demand response benefits.

Table 3-29
Summary of Benefits for Scenarios 5 & 6 vs. Scenario 4
(000s in 2004 Pre-Tax Present Value Dollars)

Benefit Categories	Scenario 4	Scenario 5	Scenario 6
Systems Operations Benefits	$307,333	$307,333	$307,333
Customer Service Benefits	8,268	8,268	8,268
Management and Other Benefits	122,316	122,316	122,316
Demand Response Benefits	367,109	167,836	165,173
TOTAL	$805,027	$605,754	$603,091

Scenario 5 assumes that 22 percent of AMI metered residential and C&I customers would opt in to the CPP-Pure rate and remain there until 2021. We used the Momentum Market Intelligence (MMI) model developed from customer survey data in the SPP to determine the customer enrollment percentage in the first year and used that same percentage for every year in the analysis.

Scenario 6 assumes that 11 percent of AMI metered residential customers would opt in to the CPP-F rate and 8 percent of the metered C&I customers would opt in to the CPP-V rate and remain there until 2021, respectively. As in Scenario 5, we used the MMI model to determine customer enrollment percentage in the first year and used that same percentage for every year in the analysis.

As described in Volume 2, the SPP experiment did not examine customer behavior to CPP-Pure rates so we used the price elasticity estimates for CPP-F from the SPP for CPP-Pure. Also, the SPP did not find statistically significant or representative C&I customer behavior to CPP-V rates. As a proxy, we used 25 percent of the residential price elasticity found for CPP-F for C&I, which is supported by the literature. Accordingly, the demand response for CPP-Pure is the same as for CPP-F; however, the enrollment to CPP-Pure versus CPP-F is slightly different due to differences in rate design and bill impacts.

The demand response benefits for Scenarios 5 and 6 are shown in Table 3-30 below.

Table 3-30 Demand Response Benefits for Scenario 5 (Current Default with Opt-in to CPP-Pure) and Scenario 6 (Current Default with Opt-in to CPP-F or CPP-V)				
	Scenario	**No. of Meters (Customers) Year 2021**	**Percent of Eligible Meters**	**Present Value ($ millions)**
Meters Eligible for TDRs	5	4,835,650		
Customers Enrolled on CPP-Pure	5	1,107,993	22	
Customers Enrolled on Tiered Rate	5	3,727,657	78	
Total DR-1 Benefits	5			$148
Total DR-2 Benefits	5			$19
Total DR Benefits Scenario 5	5			$167
Meters Eligible for TDRs	6	4,835,650		
Customers on CPP-F (Scenario 6)	6	589,078	11	
Customers on CPP-V (Scenario 6)	6	403,108	8	
Customers Enrolled on Tiered Rate	5	3,843,464	81	
Total DR-1 Benefits	6			$147
Total DR-2 Benefits	6			$19
Total DR Benefits Scenario 6	6			$165

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix B.

For Scenario 5, the Value of Service loss is approximately $78.1 million ($2004 present value), reducing the total demand response benefit from $168 to $80.7 million. For Scenario 6, the Value of Service loss is approximately $78.5million (2004 present value), reducing the total demand response benefit from $165 to $86.7 million.

3. Uncertainty and Risk Analysis

Scenarios 5 and 6 costs and operational benefits risks and analysis results are the same with an estimated cost of $1.15 and a range of $1.11 to $1.26 for these scenarios. The statistical analysis indicates that our cost estimate has less than a twelve percent confidence. This means that the project has an eighty-eight percent chance of overrunning. Our preliminary cost estimates do not include contingency. However, based on our analysis, we should consider a contingency of approximately $69 million in our business case to reduce the risk of overrun. This contingency amount is the difference between our cost estimate and the value at the ninety percent confidence level.

With regard to the demand response uncertainty, we believe that using price elasticity for CPP-F as a proxy for CPP-Pure likely overstates the demand response for CPP-Pure because customers on CPP-F rates also have a TOU portion of the rates on non-CPP days, which encourages customers to make “permanent” adjustments to usage with programmable thermostats (not provided) or other behaviors. In contrast, CPP-Pure events would only happen twelve days during the summer.

4. Net Present Value Analysis

Table 3-31 summarizes the overall pre-tax costs and benefits of Scenarios 5 and 6. Also shown is the after-tax NPV for these scenarios on a cash flow basis, and the present value of the revenue requirement over the sixteen-year analysis period.

Table 3-31 Summary of Cost/Benefit Analysis for Scenarios 5 & 6 ($ Millions)					
Scenario	Costs	Benefits	Pre-tax Present Value	After-Tax NPV	Rev. Req. Present Value
Scenario 5	$1,150.1	$605.7	($544.4)	($423.6)	($996.7)
Scenario 6	$1,150.1	$603.1	($547.1)	($425.2)	($999.4)

As shown in Table 3-31 above, our Scenario 5 analysis results in a negative Revenue Requirement present value of $996.7 million and our Scenario 6 analysis results in a negative Revenue Requirement present value of $999.4 million. Neither Scenario 5 nor Scenario 6 supports the implementation of full AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the Scenario 5 and 6 analyses, 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.

F. <u>**Scenario 7: Operational Plus Demand Response Plus Reliability - CPP-F/CPP-V Default with Opt-Out**</u>

Scenario 7 is similar to Scenario 4 except that it adds a reliability element to the full operational deployment of AMI. The Ruling directs us to evaluate additional reliability benefits, which we do by coupling the active use of load control technology. For the reliability component of this scenario, we have chosen the Advanced Load Control (ALC) program included as part of our Long-Term Procurement Plan (LTPP) and in our 2005 Demand Response Proposals which were filed on October 15, 2004.[27] This proposed ALC program is described in our Business As Usual Case as a planned upgrade to the existing systems that will be impacted by the potential deployment of AMI. As with Scenario 4, the assigned customer acceptance rate of the default tariffs (CPP-F for residential customers and CPP-V for C&I customers) in this scenario is eighty percent, with twenty percent opting-out to either TOU or their current tariff on an equal basis. Scenario 7 differs from Scenario 4 in that the costs and benefits of the ALC program are included in this scenario, whereas they were excluded in Scenario 4.

Since this scenario assumes that eighty percent of customers are on CPP rates, our ALC program and customer projections are necessarily "scaled back." This is because, as currently defined, customers cannot participate on both CPP and ALC at the same time. Independent of AMI, the ALC program is projected to enroll 500,000 customers. In this scenario with eighty percent CPP participation, we assume only 100,000 customers will participate given the CPP rates. Although this scenario includes the lower costs and benefits of the "scaled-back" load control program, by definition it does not incorporate the secondary (resource plan) impacts of those program reductions. Scenario 8, to be presented in the next section, will reflect the costs and benefits of a less constrained ALC program by reducing the CPP participation assumption from eighty percent down to nearly twenty percent.

1. <u>Costs</u>

Table 3-32 summarizes the costs by category of Scenario 7 compared to those for Scenario 4.

[27] SCE's Demand Response Program Proposals for 2005-2008, in R.02-06-001.

Table 3-32 Summary of Costs for Scenario 7 vs. Scenario 4 (000s in 2004 Pre-Tax Present Value Dollars)			
Cost Categories	**Scenario 4**	**Scenario 7**	**Difference**
Metering System Infrastructure	$668,399	$775,060	$106,661
Communications Infrastructure	41,974	41,974	-0-
Information Technology Infrastructure	206,003	206,003	-0-
Customer Service Systems	211,460	211,460	-0-
Management and Miscellaneous Other	106,086	106,086	-0-
TOTAL:	$1,233,922	$1,340,583	$106,661

The only cost code that changes when evaluating Scenario 7 in relation to Scenario 4 is MS-12. In Scenario 7, this cost code captures the costs associated with the ALC program. The activities and associated costs are discussed in detail in the following section.

a) Meter System Installation and Maintenance

The only cost difference between Scenarios 4 and 7 is related to the ALC program. The ALC program modifies the existing air conditioning load control program to include an economic dispatch option. In addition, new digital and programmable thermostats are combined with the existing load control switches. Customers will be provided an incentive payment in exchange for allowing SCE to dispatch the program when most economically effective as well as when emergency situations arise.

In Scenario 7, the cost estimates of $107 million are incurred over the 2006 to 2021 timeframe and are captured in cost category MS-12. These estimates are based upon the assumption that we will have approximately 100,000 customers participating in our new ALC program.[28] A majority of the $107 million

[28] This estimate assumes that the customers that are participating on our existing air conditioning cycling program will be migrated to the new program.

cost estimate is associated with the customer incentive payments. Customers who sign up on the ALC program will have the option of selecting from two different options during an event: 1) shedding 100 percent of their load, or 2) shedding fifty percent of their load, or increasing their temperature setting by 4º F. Incentive payments vary by the option selected and are paid only during the summer season, defined as the first Sunday in June to the first Sunday in October. The average incentive payment, assuming four ton per air conditioning unit and thirty days per month, is $86.40 for customers selecting the 100 percent load shed option. Customers opting for the fifty percent load shed option will receive on average $48.00. This fifty percent load shed incentive level is assumed to be the same as the incentive level associated with the 4ºF set-back option. We also plan to incur minimal costs on an annual basis associated with program administration and customer communications.

b) Communications Infrastructure

The communication infrastructure costs for Scenario 7 are identical to those contained in Scenario 4.

c) Information Technology Infrastructure

The information technology infrastructure costs for Scenario 7 are identical to those contained in Scenario 4.

d) Customer Service Systems

The customer service systems costs are the same in Scenario 7 as they are in Scenario 4.

e) Management and Miscellaneous Other

The management and miscellaneous other costs for Scenario 7 are identical to those contained in Scenario 4.

2. Benefits

Scenario 7 benefits are summarized below in Table 3-33. These benefits are the same as those described previously for Scenario 4, except the demand response benefits are expected to increase by $158.3 million (going from $367.1 million in Scenario 4 to $525.4 million in Scenario 7). The demand response benefits difference is attributed to the contribution of the ALC deployment.

Table 3-33
Summary of Benefits for Scenario 7 vs. Scenario 4
(000s in 2004 Pre-Tax Present Value Dollars)

Benefit Categories	Scenario 4	Scenario 7	Difference
Systems Operations Benefits	$307,333	$307,333	$-0-
Customer Service Benefits	8,268	8,268	-0-
Management and Other Benefits	122,316	122,316	-0-
Demand Response Benefits	367,109	525,439	158,330
TOTAL:	$805,027	$963,357	$158,330

a) System Operations Benefits [SB-1 through SB-13]

The benefits in Scenario 7 are the same as those described in Scenario 4.

b) Customer Service Benefits [CB-1 through CB-13]

The benefits in Scenario 7 are the same as those described in Scenario 4.

c) Management and Other Benefits [MB-1 through MB-10]

The benefits in Scenario 7 are the same as those described in Scenario 4.

d) Demand Response Benefits [DR-1 through DR-4]

Under Scenario 7, 80 percent of residential customers would default to a CPP-F rate, and 80 percent of C&I customers less than 200 kW in demand would default to the CPP-V rate. Demand response benefits of customers above 200 kW are found in Scenarios 12 and 13 (*see* Volume 4). Residential customers opting out to a TOU rate or their current rate would be eligible to enroll in the ALC program. If 80 percent of the residential customers are defaulted on CPP-F rates, this leaves only about 400,000 customers remaining to be eligible for load control. SCE also assumes a 25 percent market penetration for a load control program resulting in about 100,000 residential customers on load control, which is essentially equivalent to our existing A/C cycling program. So, we assume that for this scenario that there would be no significant growth of our ALC program above the current air conditioning cycling program. For small C&I customers, no reliability programs are assumed beyond the existing Smart Thermostat program. This is because we assume that if load control was offered to small C&I customers, it would be done so on a voluntary basis. Since that program is already available, we did not assume additional growth above today's program. The Demand Response benefits for this scenario are included in Table 3-34 below.

We used the same Ruling prescribed demand response benefit values for capacity and energy for reliability demand reductions as for price responsive demand. This is because in our October 15, 2004 demand response filing, we determine the cost effectiveness of ALC using similar values. We see no justification for differential valuations between price responsive demand and reliability demand reductions in this preliminary analysis. Even if ALC were assigned higher capacity and energy values than price responsive demand reductions, that differential would not result in a higher NPV for this Scenario relative to business as usual which would have the full roll out of ALC.

Table 3-34
CPP-F/CPP-V Default with Opt-Out Plus Reliability (Scenario 7)

	No. of Meters (Customers) Year 2021	Percent of Eligible Meters	Present Value ($ millions)
Meters Eligible for TDRs	4,835,650		
Customers Enrolled on CPP-F/V	3,868,520	80	
Customers Enrolled on Current	383,565	10	
Customers Enrolled on TOU	483,565	8	
Customers Enrolled in ALC	100,000	2	
Total DR-1 Benefits			$466
Total DR-2 Benefits			$59
Total Demand Response Benefits			$525

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix B. For this scenario, the Value of Service loss is approximately $161.2 million (2004 present value), reducing the total demand response benefit from $525 to $364.2 million.[29]

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[29] Value of service loss for the ALC portion of demand response is not included, but may also apply.

3. Uncertainty and Risk Analysis

For Scenario 7, the total present value cost estimate is $1.234 billion. We developed cost ranges as described in Section III.C and applied a Monte Carlo statistical analysis of costs that resulted in a range of $1.195 billion to $1.343 billion for this scenario. The statistical analysis indicates that our cost estimate has less than a thirteen percent confidence. This means that the project has an eighty-seven percent chance of overrunning. Our preliminary cost estimates do not include contingency. However, based on our analysis, we should consider a contingency of approximately $68 million in our final application to reduce the risk of overrun. This contingency amount is the difference between our cost estimate and the value at the ninety percent confidence level.

The demand response uncertainty of this scenario is the same as stated in Scenario 4 above.

4. Net Present Value Analysis

Table 3-35 summarizes the overall pre-tax costs and benefits of Scenario 7. 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 sixteen-year analysis period.

Table 3-35
Summary of Cost/Benefit Analysis for Scenario 7 (000s)

Costs	Benefits	Pre-tax Present Value	After-Tax NPV	Rev. Req. Present Value
$1,340.6	$963.4	($377.2)	($324.3)	($831.8)

Scenario 7 analysis results in a negative Revenue Requirement Present Value of $831.8 million, and it does not support the implementation of full AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the Scenario 7 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.

G. Scenario 8: Operational Plus Demand Response Plus Reliability - Current Default with Opt-In to CPP Pure

Scenario 8 also adds a reliability element to the full operational deployment of AMI. For the reliability component of this scenario, as was the case in Scenario 7, we chose the Advanced Load Control (ALC) program that was included as part of our LTPP in our 2005 Demand Response Proposals filed on October 15, 2004.[30] As with Scenario 5, Scenario 8 assumes the existing tariff structures will remain as the "default" tariff and twenty-three percent of the customers will opt in to a "CPP-Pure" rate option. Scenario 8 differs from Scenario 5 in that the costs and benefits of the ALC program are included in this scenario. As mentioned previously, AMI and ALC are not mutually exclusive and this scenario recognizes the interaction of these two programs.

Since we are to assume that only twenty-three percent of customers are on CPP rates in this scenario, our ALC program and customer projections are only partially curtailed. Independent of a CPP tariff for residential customers, the program is projected to attract 500,000 participants. In this scenario, we assume roughly twenty percent of the full ALC rollout would be precluded by CPP customers. So, we therefore, assume that 420,000 customers will participate in ALC.

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[30] SCE's Demand Response Program Proposals for 2005-2008, in R. 04-04-003

1. Costs

Table 3-36 summarizes the cost by category of Scenario 8 compared to the costs for Scenario 5.

Table 3-36
Summary of Costs for Scenario 8 vs. Scenario 5
(000s in 2004 Pre-Tax Present Value Dollars)

Cost Categories	Scenario 5	Scenario 8	Difference
Metering System Infrastructure	$668,399	$937,269	$268,870
Communications Infrastructure	41,974	41,974	0
Information Technology Infrastructure	197,189	197,189	0
Customer Service Systems	180,806	180,384	(422)
Management and Miscellaneous Other	61,779	54,315	(7,463)
TOTAL:	$1,150,147	$1,411,131	$260,984

The activities and associated costs are discussed in detail in the following section.

a) Meter System Installation and Maintenance

The most significant cost difference between Scenarios 5 and 8 is related to the ALC program. The ALC program modifies the existing air conditioning load control program to include an economic dispatch option. In addition, new digital and programmable thermostats are combined with the existing load control switches. Customers will be provided an incentive payment in exchange for allowing SCE to dispatch the program when most economically effective as well as when emergency situations arise.

In Scenario 8, the cost estimates of $268.9 million, which are captured in cost code MS-12, are based upon the assumption that we will have approximately 420,000 customers participating in our new ALC program by 2011.[31] We are also assuming that the ALC program is approved in early 2005.

The cost estimate of $268.9 million is comprised of the costs associated with equipment, installation, customer incentive payments and program administration that are incurred over the 2006 to 2021 timeframe. We will incur equipment and installation costs associated with enrolling additional customers on the new ALC program. In terms of equipment costs, our estimates are based upon thirty percent of participating customers choosing to have a direct load control switch installed on their air conditioning unit. This installation will be handled by a contractor resource. The equipment and installation costs are estimated at $161 per customer.

For the remaining seventy percent of customers, we are assuming that a load control transceiver will be embedded in the AMI meter.[32] This transceiver will have the ability to control the customer's air conditioning unit by communicating with the customer's thermostat. The equipment costs associated with the thermostat and load control transceiver are estimated to be $95 per customer. In addition, we will incur installation costs. The contractor resource costs associated with installing a thermostat in a customer's home or business are estimated to be $90. In terms of the load control transceiver installation costs, we are assuming that fifty percent of the meters will have the module embedded by the vendor at the time of manufacturing. In these cases, there will be no additional installation costs since we will be utilizing the installers discussed in cost code MS-5 in Scenario 1 to handle the installation of the AMI meters. However, in fifty percent of the cases, we are assuming that the AMI meter will already have been

[31] This estimate assumes that the customers that are participating in our existing air conditioning cycling program will be migrated to the new program.

[32] Conceptual design is neither proven nor commercially available today.

installed and will need to be replaced with one that contains the load control transceiver. In those cases, we have captured the costs associated with having an installer visit the customer's site to reinstall the meter.

The majority of the $268.9 million cost estimate can be attributed to customer incentive payments. Customers who sign up on the ALC program will have the option of selecting from two different options during an event: 1) shedding 100 percent of their load, or 2) shedding fifty percent of their load, or increasing their temperature setting by 4º F. Incentive payments vary by the option selected and are paid only during the summer season, defined as the first Sunday in June to first Sunday in October. The average incentive payment, assuming four ton per air conditioning unit and thirty days per month, is $86.40 for customers selecting the 100 percent load shed option. Customers opting for the fifty percent load shed option will receive on average $48.00. This fifty percent load shed incentive level is assumed to be the same as the incentive level associated with the 4ºF set-back option. We also plan to incur minimal costs on an annual basis associated with program administration and customer communications.

b) **<u>Communications Infrastructure</u>**

The communications infrastructure costs for Scenario 8 are identical to those contained in Scenario 5.

c) **<u>Information Technology Infrastructure</u>**

The information technology infrastructure costs for Scenario 8 are identical to those contained in Scenario 5.

d) **<u>Customer Service Systems</u>**

Customer Communications and Marketing costs (cost code CU-10) are decreasing by $422,000 between Scenario 5 and 8. This is due to the assumption that the "opt-in" participation rate will be lower for Scenario 8 than assumed for Scenario 5. The smaller participant base on CPP rates affects the mass media costs and the CPP event notification costs in cost code CU-10.

e) Management and Miscellaneous Other

The management and miscellaneous other costs that are captured in cost code M-14 are decreasing by $7.5 million between Scenario 5 and 8. Cost code M-14 relates to customer acquisition and marketing costs which will also be reduced due to the assumed reduction in customer opt-in participation on CPP rates under Scenario 8 relative to Scenario 5.

2. Benefits

Table 3-37 summarizes Scenario 5 and Scenario 8 benefits by category.

Table 3-37
Summary of Benefits for Scenario 8 vs. Scenario 5
000s in 2004 Pre-Tax Present Value Dollars)

Benefit Categories	Scenario 5	Scenario 8	Difference
Systems Operations Benefits	$307,333	$307,333	-0-
Customer Service Benefits	8,268	8,268	-0-
Management and Other Benefits	122,316	122,316	-0-
Demand Response Benefits	$167,836	$557.413	$389,577
TOTAL:	$605,754	$995,331	$389,577

The difference in benefits between Scenario 5 and 8 is attributed to demand response benefits. The difference in demand response benefits is due to the addition of the ALC program deployment for reliability.

As in Scenario 5, this scenario assumes that residential and C&I customers will opt in to the CPP-Pure rate and that a group of other residential customers, either on a TOU rate or their current rate would enroll in ALC, providing a reliability feature. SCE used the MMI model to determine customer enrollment percentage in the first year and used that same percentage for every year in the analysis. For the purposes of the analysis, SCE used the demand response behavior in the SPP for CPP-F as a proxy for CPP-Pure since the latter was not tested in the experiment. The demand response benefits are shown in Table 3-38 below.

Table 3-38
Current Default with Opt-in to CPP-Pure Plus Reliability (Scenario 8)

	No. of Meters (Customers) Year 2021	Percent of Eligible Meters	Present Value ($millions)
Meters Eligible for TDRs	4,835,650		
Customers Enrolled on CPP-Pure	1,107,993	23	
Customers Enrolled on Current	3,307,657	69	
Customers Enrolled on ALC	420,000	8	
Total DR-1 Benefits			$493
Total DR-2 Benefits			$64
Total DR Benefits			$557

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix B. For this scenario, the Value of Service loss is approximately $78.1 million (2004 present value dollars), reducing the total demand response benefit from $557 to $479.3 million.[33]

[33] Value of service loss for the ALC portion of demand response is not included, but may also apply.

3. Uncertainty and Risk Analysis

For Scenario 8, the total present value cost estimate is $1.411 billion. We developed cost ranges as described in Section III.C and applied a Monte Carlo statistical analysis of costs that resulted in a range of $1.367 billion to $1.532 billion for this scenario. The statistical analysis indicates that our cost estimate has less than a thirteen percent confidence. This means that the project has a eighty-seven percent chance of overrunning. Our preliminary cost estimates do not include a contingency. However, based on our analysis, we should consider a contingency of approximately $69 million in our final application to reduce the risk of overrun. This contingency amount is the difference between our cost estimate and the value at the ninety percent confidence level.

The uncertainties and risks associated with demand response of this scenario are the same as those for Scenario 5 described above.

4. Net Present Value Analysis

Table 3-39 summarizes the overall pre-tax costs and benefits of Scenario 8. 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 sixteen-year analysis period.

Table 3-39
Summary of Cost/Benefit Analysis for Scenario 8 ($ Millions)

Costs	Benefits	Pre-tax Present Value	After-Tax NPV	Rev. Req. Present Value
$1,411.1	$995.3	$415.8	($347.2)	($871.2)

Our Scenario 8 analysis results in a negative Revenue Requirement Present Value of $871.2 million and does not support the implementation of full AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the Scenario 8 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.

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IV.

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 scenarios.[34] The revised preliminary revenue requirement presented in this section summarizes the operating expenses and investment-related costs identified in Section III above.

Table 3-40 provides the estimated net AMI-related revenue requirement and average customer monthly dollar impacts for each of the full deployment scenarios.

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

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[34] Due to the 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 2020. These unrecovered costs [of approximately $58 million in unrecovered net plant for the full-deployment scenarios (Scenarios 1-8), and $3.4 million for the Zone 4 partial-deployment scenarios (Scenarios 14-21),] 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' fifteen-year life and their later in-service dates·

anticipated O&M expenses and capital costs associated with expected rate base amounts including depreciation, applicable taxes and return on rate base calculated at the Commission-authorized rate of return.[35] The return on rate base amounts included in the Revenue Requirements presented in Table 3-48 uses our currently authorized rate of return on rate base of 9.07 percent.

As discussed in Sections II and III of 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.

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 include: (1) Customer Service-related O&M reductions; (2) existing meter revenue requirement reductions; and (3) procurement cost reductions due to demand response.

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[35] SCE has assumed a fifteen-year recovery period associated with the new meters.

Table 3-40
AMI Revenue Requirement – Full Deployment
(000s of Dollars)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Scenario 1 - Full-Operational-Utility																
AMI Meter Installation Revenue Requirements	76,791	98,992	138,800	160,257	179,707	153,747	147,565	142,223	137,405	132,631	131,429	129,296	124,984	120,776	116,710	101,385
Stranded Cost Revenue Requirement - 5 year	116,136	111,876	103,474	72,094	126,892	-	-	-	-	-	-	-	-	-	-	-
Less:																
Expected O&M Reductions	(60)	(6,192)	(21,587)	(34,483)	(52,181)	(59,693)	(61,933)	(64,023)	(66,459)	(68,725)	(71,321)	(73,758)	(76,560)	(78,695)	(80,846)	(83,156)
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Net AMI-related Rev Req Impact	**189,961**	**202,724**	**215,897**	**193,079**	**249,628**	**89,263**	**80,842**	**73,410**	**66,156**	**59,116**	**55,318**	**50,748**	**43,634**	**37,291**	**31,074**	**13,439**
Avg Monthly Customer Dollar Impact	**3.29**	**3.46**	**3.64**	**3.21**	**4.10**	**1.45**	**1.29**	**1.16**	**1.03**	**0.91**	**0.84**	**0.76**	**0.65**	**0.55**	**0.45**	**0.19**
Scenario 3 - Full-DR-TOU-Opt-20																
AMI Meter Installation Revenue Requirements	131,863	154,783	199,410	218,847	236,044	202,425	194,877	190,339	183,528	181,300	148,130	148,184	143,506	138,468	133,892	115,110
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)	(6,647)	(13,305)	(20,022)	(24,804)	(26,365)	(26,706)	(27,057)	(27,410)	(27,772)	(28,133)	(28,504)	(28,876)	(29,258)	(29,640)	(30,034)
Total Net AMI-related Rev Req Impact	**244,998**	**251,314**	**262,650**	**231,078**	**280,459**	**110,940**	**100,791**	**93,790**	**84,167**	**79,287**	**43,136**	**40,356**	**32,479**	**24,898**	**17,766**	**(3,748)**
Avg Monthly Customer Dollar Impact	**4.25**	**4.29**	**4.43**	**3.84**	**4.60**	**1.80**	**1.61**	**1.48**	**1.31**	**1.22**	**0.66**	**0.61**	**0.48**	**0.37**	**0.26**	**(0.05)**
Scenario 4 - Full-DR-CPP-Opt-20																
AMI Meter Installation Revenue Requirements	131,863	155,783	201,359	221,596	239,647	206,354	198,942	194,586	187,942	185,917	152,911	153,179	148,685	143,881	139,506	120,988
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)	(17,971)	(36,072)	(54,315)	(67,301)	(71,560)	(72,475)	(73,407)	(74,348)	(75,306)	(76,271)	(77,254)	(78,246)	(79,256)	(80,275)	(81,314)
Total Net AMI-related Rev Req Impact	**244,998**	**240,989**	**241,833**	**199,534**	**241,564**	**69,674**	**59,088**	**51,688**	**41,643**	**36,369**	**(221)**	**(3,400)**	**(11,713)**	**(19,687)**	**(27,255)**	**(49,149)**
Avg Monthly Customer Dollar Impact	**4.25**	**4.12**	**4.08**	**3.32**	**3.97**	**1.13**	**0.95**	**0.82**	**0.65**	**0.56**	**(0.00)**	**(0.05)**	**(0.17)**	**(0.29)**	**(0.40)**	**(0.71)**
Scenario 5 - Full-DR-CPP-Pure																
AMI Meter Installation Revenue Requirements	129,965	148,064	189,881	205,839	220,296	189,128	180,709	175,086	167,402	163,895	146,496	146,503	141,770	136,691	132,076	113,252
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)	(8,315)	(16,620)	(25,004)	(31,026)	(33,035)	(33,466)	(33,910)	(34,356)	(34,814)	(35,271)	(35,740)	(36,210)	(36,693)	(37,177)	(37,676)
Total Net AMI-related Rev Req Impact	**243,100**	**242,927**	**249,807**	**213,088**	**258,489**	**90,975**	**79,864**	**71,685**	**61,095**	**54,840**	**34,364**	**31,439**	**23,407**	**15,686**	**8,413**	**(13,247)**
Avg Monthly Customer Dollar Impact	**4.21**	**4.15**	**4.21**	**3.54**	**4.24**	**1.47**	**1.28**	**1.13**	**0.95**	**0.85**	**0.52**	**0.47**	**0.35**	**0.23**	**0.12**	**(0.19)**
Scenario 6 - Full-DR-CPP-FV																
AMI Meter Installation Revenue Requirements	129,965	148,064	189,883	205,839	220,297	189,131	180,709	175,085	167,401	163,896	146,496	146,502	141,769	136,691	132,076	113,252
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)	(8,184)	(16,330)	(24,557)	(30,508)	(32,521)	(32,951)	(33,393)	(33,837)	(34,293)	(34,748)	(35,216)	(35,685)	(36,166)	(36,649)	(37,146)
Total Net AMI-related Rev Req Impact	**243,100**	**243,058**	**250,099**	**213,535**	**259,007**	**91,491**	**80,379**	**72,201**	**61,613**	**55,361**	**34,886**	**31,963**	**23,933**	**16,213**	**8,941**	**(12,718)**
Avg Monthly Customer Dollar Impact	**4.21**	**4.15**	**4.22**	**3.55**	**4.25**	**1.48**	**1.29**	**1.14**	**0.96**	**0.85**	**0.53**	**0.48**	**0.36**	**0.24**	**0.13**	**(0.18)**
Scenario 7 - Full-DRR-CPP-F-20																
AMI Meter Installation Revenue Requirements	146,816	170,772	216,364	236,641	260,161	221,510	213,680	209,291	202,629	207,526	167,640	167,965	163,545	158,840	154,578	136,201
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	(23,503)	(41,426)	(59,527)	(77,765)	(90,742)	(94,988)	(95,732)	(96,363)	(97,043)	(97,781)	(98,563)	(99,401)	(100,284)	(101,221)	(102,201)	(103,235)
Total Net AMI-related Rev Req Impact	**236,501**	**232,523**	**233,383**	**191,129**	**238,637**	**61,404**	**50,568**	**43,437**	**33,635**	**35,504**	**(7,785)**	**(10,760)**	**(18,891)**	**(26,693)**	**(34,109)**	**(55,857)**
Avg Monthly Customer Dollar Impact	**4.10**	**3.97**	**3.93**	**3.18**	**3.92**	**0.99**	**0.81**	**0.69**	**0.53**	**0.55**	**(0.12)**	**(0.16)**	**(0.28)**	**(0.39)**	**(0.50)**	**(0.80)**
Scenario 8 - Full-DRR-CPP-Pure																
AMI Meter Installation Revenue Requirements	159,084	182,624	226,916	245,506	267,670	233,253	218,320	212,389	204,527	207,743	186,357	186,435	181,785	176,812	172,309	153,619
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	(28,094)	(45,522)	(62,575)	(78,865)	(92,011)	(100,414)	(103,735)	(103,959)	(104,219)	(104,523)	(104,857)	(105,233)	(105,640)	(106,085)	(106,558)	(107,069)
Total Net AMI-related Rev Req Impact	**244,178**	**240,280**	**240,887**	**198,894**	**244,878**	**67,720**	**47,205**	**38,939**	**28,357**	**28,979**	**4,638**	**1,877**	**(6,007)**	**(13,586)**	**(20,735)**	**(42,274)**
Avg Monthly Customer Dollar Impact	**4.23**	**4.11**	**4.06**	**3.31**	**4.02**	**1.10**	**0.76**	**0.62**	**0.44**	**0.45**	**0.07**	**0.03**	**(0.09)**	**(0.20)**	**(0.30)**	**(0.61)**

Appendix A

Summary of Potential Benefits - Full AMI Deployment

APPENDIX A

SUMMARY OF POTENTIAL BENEFITS - FULL AMI DEPLOYMENT

Table 3-41 summarizes the total estimated benefits we expect will result from the full deployment of AMI in the operational-only and demand response scenarios.

Table 3-41
Summary of Benefits under Full AMI Deployment
(2004 Pre-Tax Present Value Dollars in Millions)

Benefit Categories	Full Deployment Operational-only (Scenario 1)	Full Deployment With Demand Response (Scenarios 3 through 8)
Systems Operations Benefits	304.1	307.3
Customer Service Benefits	5.4	8.3
Management and Other Benefits	121.1	122.3
Demand Response Benefits	-0-	Range from 133.3 to 557.4
TOTAL:	430.6	Range from 571.3 to 995.3

All benefit codes identified in the Ruling are discussed in the following sections, whether included in the revised preliminary analysis or not.

A. System Operations Benefits (SB-1 through SB-13)

Appendix A of the ACR identified thirteen 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 four of the thirteen benefit codes for a total of $304.1 million in the operational-only scenario (Scenario 1) and $307.3 million in the demand response scenarios (Scenarios 3 through 8). 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 ACR are either already being experienced by SCE, have associated costs that more than offset the anticipated savings, or otherwise do not apply.[36]

All identified System Operations Benefits are the same for the demand response scenarios as for the operations-only scenario. The following sections address all 13 of the potential system operations benefits as described in the ruling.

1. **(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 eighty management and support personnel, eighty percent of which would be eliminated with full deployment of AMI. As described in Volume 2, full deployment of AMI will result in our ability to automatically read ninety percent of all our meters. The remaining ten percent, or approximately 470,000 meters, will continue to be read monthly by approximately 109 meter readers.[37] In addition, we expect to eliminate sixteen of the existing meter reader supervisor positions with full deployment of AMI.[38]

The reduction of eighty percent of our current meter reading organization would result in a total savings of $271 million (expressed in 2004

[36] 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.

[37] 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% of meters.

[38] These sixteen 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.

present value dollars) savings over the duration of the analysis period. With our current attrition rate of thirty-five to forty 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 eighteen months after AMI installations begin) and continue throughout the deployment years. Severance of thirty-two 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 eighty percent of our hand-held meter reading devices. This savings is reflected in benefit code MB-1.

2. <u>(SB-2) Field Service Savings (Turn-Ons / Turn Offs) And Lower Need For Pickup Reads</u>

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. For the full deployment scenarios, 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).

3. <u>(SB-3) Reduction in Energy Theft – May Provide Ability to Identify Active Accounts for Metered Accounts Not Being Billed, Broken Meters, Wrong Multipliers</u>

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 the AMI demand response scenarios, 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 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.

4. **(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 3-42 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 3-42
Reduced Phone Calls

Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Full Deployment	2,820	8,445	14,089	19,753	23,626	23,626

5. **(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.[39] 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.

6. (SB-6) Outage Management Benefits

This potential benefit has been addressed in the Business As Usual case in Volume 2 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."

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.

7. (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

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[39] SCE's Meter Infrastructure Replacement program is described in SCE's 2006 GRC Application in SCE4 Vol. 2, Chapter V.

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 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 analysis.

8. <u>(SB-8) Remote Service Connect / Disconnect</u>

We respond to over one million turn-on/turn-off service requests annually, and we disconnect and reconnect nearly one 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. In 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.

9. (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

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 AMI (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 all full deployment demand response scenarios (Scenarios 3 through 8), where our Energy Supply and Marketing

Organization (ES&M) 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.

10. <u>**(SB-10) System Planning Design Efficiency – Savings from More Accurate Information on Status of Transformers And Distribution Lines Etc.**</u>

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 eighty to eighty-five 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 AMI to create any incremental benefits in this area.

11. <u>**(SB-11) Reduction in Unaccounted for Energy (UFE)**</u>

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, twenty-four hours a day, 365 days per year. This would add over thirty-five million kWh per year in energy consumption.[40]

12. <u>(SB-12) Ability to Monitor Customer Self-Generation Into System on a Real Time Basis</u>

SCE currently has the capability of metering in fifteen 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).

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[40] This could add as much as $1.3 million per year to our cost of energy.

13. (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. Under the demand response scenarios, 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 the operational-only scenarios, 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.

B. Customer Service Benefits (CB-1 through CB-13)

The ACR identified thirteen "additional" customer service benefits. Our review of these potential areas of benefit resulted in anticipated savings from two of the thirteen, for a total savings of approximately $5.4 million in the operational-only scenario (Scenario 1) and $8.3 million in the demand response scenarios (Scenarios 3 through 8). 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 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 thirteen potential Customer Service Benefits.

1. **(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.

2. **(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 ten percent of our single-service no-lights calls. This is because approximately ten 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.

3. <u>(CB-3) May Provide Additional Opportunity to Inspect Panel, Reattachment of Unsecured Meter Boxes, Identify Any Unsafe Conditions</u>

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.

4. <u>(CB-4) Improves Billing Accuracy – Reduced Estimated Reads / Estimated Billing – Reduced Exception Billing Processing</u>

Any potential cost savings for this benefit code have been included in the estimate for benefit code CB-1 above.

5. <u>(CB-5) Customer Energy Profiles for EE / DR Targeting (Marketing)</u>

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.

6. (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.

7. (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 improved customer satisfaction and this is very hard to attach a value to. 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.

8. (CB-8) Energy Information to Customer Can Assist in Managing Loads

Though not applicable to the operational-only scenarios (Scenarios 1 and 14), we do expect a direct benefit of approximately $2.9 million in each of the demand response scenarios 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.

9. **(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 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.

10. **(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.

For all full deployment scenarios we have included all load survey metering costs in our avoided cost of new and replacement meters in benefit code MB-4.

11. **(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.

12. (CB-12) Value to Customers of More Timely And Accurate Bills

See discussion under benefit codes CB-1, CB-4 and CB-7.

C. Demand Response Benefits [DR-1 through DR-4]

The 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

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. Our approach and assumptions for each Demand Response benefit category is described in Volume 2, Section III, B, 4.

D. Management and Other Benefits (MB-1 through MB-10)

Only two of the ten potential "Management and Other" benefit codes identified in the Ruling were actually used in SCE's revised preliminary analysis. The following sections describe our review of each of the potential Management and Other benefit codes.

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

In the full deployment scenarios, we expect to reduce costs by approximately $2.9 million over the duration of the analysis period by decommissioning eighty 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.

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

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

3. **(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.

4. **(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

(Vol. 2, Section 2.B.3.c) 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 the full deployment scenarios, this avoided cost is $118.2 million over the duration of the analysis period.

5. (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.

Just how much savings may result from the one-time improvement in cash flow is a complex analytical question that remains unanswered at the time this revised preliminary analysis is being completed. We expect to be able to include some savings under this benefit code in our March 15, 2005 filing.

6. (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 twenty-five watts) than do existing electromagnetic meters. Most electromagnetic meter discs sit "idle" when less than twenty to twenty-five 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% of total metered kWh on average. For an average residential customer, this would equal approximately twenty-five 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 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 electro-mechanical counterparts. Taken on its own, this technical characteristic of electronic meters would add 4 megawatts of load twenty-four hours a day, 365 days per year. This would add over thirty-five 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.

7. **(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.

8. **(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.

9. **(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.

10. **(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 any of the deployment scenarios.

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SOUTHERN CALIFORNIA
EDISON

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(U 338-E)

Advanced Metering Infrastructure Revised Preliminary Business Case Analysis

Volume 4 – Revised Preliminary Analysis of Partial Deployment Scenarios

Before the
Public Utilities Commission of the State of California

Rosemead, California
January 12, 2005

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) PRELIMINARY ANALYSIS OF ADVANCED METERING INFRASTRUCTURE BUSINESS CASE

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I.

INTRODUCTION

The purpose of Volume 4 is to present our revised, preliminary business case analysis for each of the partial deployment scenarios identified in Attachment A of the Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure issued on July 21, 2004 (Ruling).

In Volume 2, we described our Business As Usual base case which, according to the Ruling, identifies the expected capital and maintenance costs we will incur associated with maintaining the current metering and communication systems for all customer classes, including any planned upgrades to metering and billing systems for the period 2006 to 2021. As stated in the Ruling, the Commission intends to use this base case information as the baseline for evaluating the cost effectiveness of the partial AMI deployment scenarios. Volume 3 provided the full deployment business case analysis required by the Ruling.

Section II of this volume fully describes the expected impacts to our various business processes, operations, and systems of the partial deployment scenarios using the AMI technology solution discussed in Volume 2.

Section III describes our alternative analysis of large commercial and industrial customers placed on a RTP tariff on a mandatory basis. Two separate scenarios are analyzed in Section III: Scenario 12 assumes all large customers currently equipped with RTEM meters are placed on a mandatory RTP rate; Scenario 13 assumes our current I-6 interruptible program is maintained and all other large RTEM customers are placed on a mandatory RTP rate.

The revised preliminary business case analysis for each of the partial deployment scenarios required by the Ruling is addressed in Section IV of this volume. Attachment A of the Ruling identified eight different partial deployment scenarios that the utilities are to analyze.[1] Section IV provides the detailed cost analysis in the Ruling's three major analytical categories (*i.e.,* start-up and design; installation; and operations and maintenance), along with the five applicable cost categories[2] and seventy-nine individual cost codes associated with these cost categories. The benefit analysis is also provided in these sections by the four major benefit categories and the individual benefit codes that were actually used in this analysis. A summary discussion of all forty benefit codes, whether used or not, is contained in Appendix A of this Volume. In addition, we provide a discussion of the risks and uncertainties that we have been able to identify for each of the scenarios addressed in Section IV. We also provide the net present value analysis for each partial deployment scenario in Section IV based on the costs and benefits identified in the cost and benefit categories.

Finally, Section V sets forth the preliminary Revenue Requirement and Rate Impact Analysis for each partial deployment scenario based on the detailed cost and benefits information provided in Section IV.

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[1] In our preliminary analysis filed on October 22, 2004, we provided two additional partial deployment scenarios (i.e., Scenarios 22 and 23) containing what we believe to be more reasonable assumptions relating to customer participation on the various time-differentiated default rates. We have chosen not to pursue these alternative scenarios in this revised analysis.

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

II.

OVERVIEW OF PARTIAL DEPLOYMENT BUSINESS CASE

This section describes the effects of partial deployment of AMI on all of the various operations, processes, and information technology systems located throughout the company. For purposes of the partial deployment analysis, we assume that the same RF technology solution described in Volume 2 will be used in both the full and partial deployment scenarios.

We envision two possible approaches to partial deployment. The first approach involves the existing Real Time Energy Meter (RTEM) through the use of Real-Time Pricing (RTP) for all customers with RTEM metering. Under this approach, all customers with demand levels of over 200 kW that already have RTEM metering would be placed on a RTP rate schedule. This approach would require very little additional capital because the vast majority of customers with over 200 kW of demand already have the required interval data metering and thus, additional capital expenditures for metering would only be required for new customers or replacement meters required by meter failure. Additional operation and maintenance costs for our various customer service and field operations and for information technology systems are expected to be minimal under this approach. This possible partial deployment approach is discussed further in Section III as Scenarios 12 and 13.

The second approach is based on the assumption that partial 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 capabilities. This approach is also best suited to the portion of our service territory that is geographically situated so as to result in significant meter reading savings. The portion of our service territory that meets these two criteria is Climate Zone 4, as delineated in the Statewide Pricing Pilot (SPP). We selected Climate Zone 4 from the SPP, which covers our Baseline Regions 14 and 15 for several reasons, described below.

First, to maximize meter reading savings from partial deployment, such deployment must be geographically contained. Without a distinct geographic area of focus, the deployed AMI meter sites would be scattered and savings associated with meter reading reductions would not be realized.

Second, to maximize demand response from partial deployment, we focused on those areas where customers have the highest potential for demand response. 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.[3]

Third, it is imperative that partial deployment be large enough to gain some economies of scale, but small enough that deployment risks can be more easily managed. We believe Zone 4, with about 450,000 customers, meets these criteria.

Finally, with the selection of Zone 4 for a partial deployment, there are benefits in terms of IT and Communications infrastructure development. Given that the geography of Zone 4 contains a mix of rural low density meters sites (such as those within the desert areas) and high density residential meter sites (such as those within the Palm Springs area), partial deployment here will better allow us to assess the actual capabilities and broad geographical coverage of the communications infrastructure. This first hand experience will be valuable and can be used in planning future deployment. In addition, by deploying AMI on a smaller scale, we will be able to effectively test the end-to-end systems supporting the meter

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[3] "Statewide Pricing Pilot Summer 2003 Impact Analysis," August 9, 2004, Charles River Associates, p. 83.

supply chain and interval data management without being subjected to the additional risks that accompany the full deployment scenarios.

Overall, we expect approximately 435,000 meter sites to provide the reliable communications necessary for AMI deployment in a Zone 4 partial deployment. The Zone 4 meter sites are located within six of our service centers. The service centers involved are Palm Springs, Victorville, Antelope Valley, Redlands, San Jacinto, and Valencia.

The cost estimates described in the next section are based on the assumption that the Zone 4 deployment is completed in 2006 and that the required communications network is operational by July 2007. A significant difference between the Zone 4 partial deployment case and the full deployment case is the assumption regarding the actual percentage of "communicating" meters. Whereas we assumed ninety percent of full deployment meters would be capable of communicating successfully, this number drops down to seventy percent in the partial deployment case. In the twenty percent opt-out demand response scenarios, the result would be that only eighty percent of the seventy percent communicating customer accounts would be able to actually participate on the default rate (*i.e.*, TOU or CPP).

To help facilitate the Commission's understanding of the implications of partial deployment, the following sections describe the Zone 4 partial deployment case by assessing such deployment effects on our operations, using the five applicable cost categories and four benefit categories, as well as the cost and benefit codes identified in Attachment A to the Ruling. The effects on our operations, processes, and information technology systems described in the following sections apply to Scenarios 14 through 21 and do not apply to the System-wide implementation of RTP rates for the over 200 kW customers presented in Scenarios 12 and 13.

A. Metering System Installation and Maintenance Category

This section describes the operations, processes, and systems that are affected by partial deployment for activities that fall under the meter system, installation and maintenance category. Under the partial deployment cases, this category involves our meter procurement, supply chain management, testing, installation, and associated support activities.

1. Description of Meter System Installation and Maintenance Activities Impacted by Partial Deployment

The meter system installation and maintenance category involves all of our activities associated with meter procurement, supply chain management, testing, installation, and other support. The effect of a Zone 4 partial deployment on these activities is described in detail in the following subsections.

a) Meter Procurement

As with the full deployment scenarios, we will procure six different types of meters for a partial AMI deployment. Although this deployment is on a much smaller scale, we will still need to modify many of our inventory activities to accommodate partial deployment since our current manual processes cannot accommodate the volumes expected under partial deployment. We will address this issue by automating our procurement and supply chain processes through the use of RFID technology.

b) Supply Chain Management

Currently, our Procurement and Material Management (PAMM) group receives, stocks, and distributes approximately 120,000 meters per year. Under partial deployment, PAMM will increase its distribution to approximately

440,000 meters to support the initial deployment. In addition, it is estimated that there will be approximately 195,000 additional meters that will need to be processed from 2006 to 2021 due to meter replacements that result from the failures of meters already in the field. The estimated number of meter failures by year end under partial deployment is shown in Table 4-1 below.

Table 4-1
Estimated Meter Failures by Year

Year	Estimated Meter Failures
2006	14,604
2007	43,002
2008	21,811
2009	13,065
2010	8,718
2011	8,687
2012	8,653
2013	8,617
2014	8,576
2015	8,536
2016	8,495
2017	8,451
2018	8,407
2019	8,360
2020	8,312
2021	8,263
Total	194,557

Given our prior experience with meter vendor reliability, we will maintain approximately three months worth of inventory in our distribution facility. Also, the distribution facility will need to begin stocking meters by the fourth quarter of 2005 so that PAMM can begin distribution in support of deployment and installation to the various SCE locations beginning in January 2006.

Under partial deployment, PAMM will continue to deliver meters to the service centers once or twice a week so that materials are received on a just-in-time basis. This will avoid the need for additional secure storage. Additional personnel will be required in the service centers to process the meters as they are received. The meters are then stored in a secure area until they are scheduled for distribution. Due to the short-term nature of this project, we propose to use a Temporary Project Accountant position to process the meters at the service centers.[4] The Temporary Project Accountants will also be responsible for distribution of the meters to the installers according to a still-to-be developed installation schedule. Once the installers replace an existing meter with a new AMI meter, the returned meter will be processed at various service centers for salvage purposes.

c) Meter Testing

For residential meters, we plan to test 100 percent of the first two shipments of meters for quality assurance purposes. After that, we will use a statistically significant sampling method to test the remaining meters. For commercial meters, we plan to test 100 percent of the first 10,000 commercial meters for quality assurance purposes. We plan to use a statistically significant sampling method similar to that used for residential meter testing for the remainder of these meters.

Meter testing will be conducted at our existing Meter Shop facility, although this shop will need to be reconfigured to handle the increased workload. Although partial deployment of AMI will decrease some of the existing meter test work, the workload will increase overall because of the scale and pace of partial deployment. Consequently, additional personnel will be required to handle this increased testing.

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

d) Meter Installation

(1) Residential and small commercial (less than 20 kW)

As discussed in detail in Volume 2, the communications network and information technology applications necessary for AMI deployment will not be operational until June 2007. Accordingly, we expect to continue our current meter reading and field service practices for all meters, even those that receive an AMI meter before June 2007.[5] We analyzed various methods to handle the AMI installations and continue our existing field work. Since partial deployment is short-term in nature, we determined that it would be more cost effective to hire temporary personnel rather than full-time personnel. The use of temporary resources depends on the assumption that we will receive IBEW concurrence to reactivate the project temporary meter reader job classification[6] and approve the creation of a project temporary installer job classification.

(2) Complex Meter Installations

Under a Zone 4 partial deployment, there are approximately 20,000 meters that are considered complex and need to be installed by Meter Technicians with specialty training. These complex meters are associated with Rate Schedule GS-2 and accounts with monthly energy demands of over 20 kW. They are also used for 240v three-phase accounts and residential accounts with current transformers and potential transformers.

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[5] As described in Volume 2, Section II, in addition to manually read meters, SCE currently has more than 350,000 meters that are being read via van-based automated meter reading. As part of the RTEM project, SCE is collecting interval data on a daily basis from more than 12,000 commercial customers.

[6] IBEW approved the use of the Project Temporary Meter Reader job classification for the AMR deployment which took place in 2000. We understand that the use of non-labor on utility construction projects is currently under Commission review and thus, if represented employee labor were required, the cost estimates for meter installation could change.

e) Support Related Costs

In order to support partial AMI deployment, our field personnel will need to attend various training classes. As new meter readers are hired to replace those who have taken Project Temporary Installer positions, they will need to attend new hire meter reading classes. As existing Meter Readers transition to Field Service Representative positions to replace those who have taken Project Temporary Installer positions, they will need to take classes on handling billing inquiries and using various customer service systems. Project Temporary Installers, who will handle meter installations for the residential and less than 20 kW commercial accounts, will need to undergo a training program that covers Meter Installation Procedures and Practices as well as a class on how to use our meter tracking systems.

B. Communications Infrastructure

In a Zone 4 partial deployment, we will be utilizing the same radio frequency communications system as detailed in Volume 2. This system is comprised of collectors, packet routers, and MCC take-out points. Our AMI technology solution leverages our already-existing network and expands from there. New collectors will be mounted in the power space of a utility pole or streetlight and will communicate with radios in the residential and less than 20 kW meters to transmit meter data throughout the network to the MCC take-out points. The meter technology for greater than 20 kW customers includes the use of "radio under the meter cover" technology that will provide an RF "mesh-type" network of an additional 16,000 radios to the overall AMI communications network. Given the number of meters in partial deployment, we anticipate congestion on the communications network, particularly for those locations in close proximity to the MCC take-out points. The installation of a packet router will help ease this congestion and ensure data transmission to the SCE network in a timely manner so that it is available for bill calculation. The MCC take-out points need to be installed in order to collect the meter data and transmit it to SCE's computing network. Under partial deployment, we will need to supplement the 100 MCC take-out points currently in place.

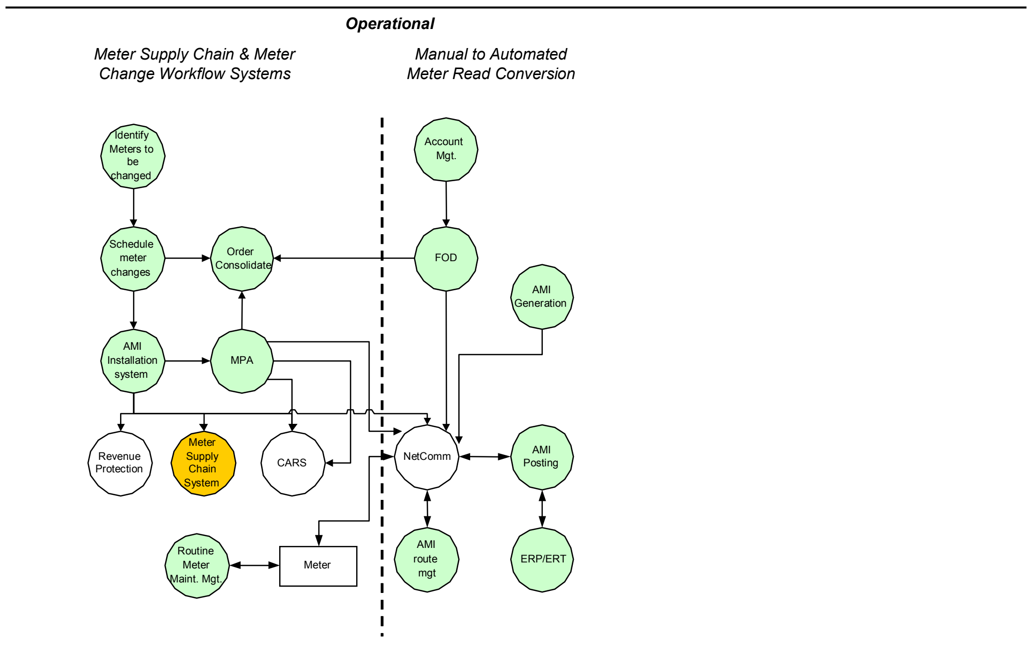
C. Information Technology Infrastructure

The information technology and application cost category captures the costs associated with applications and computer services. These activities are described in more detail in the sections that follow.

1. Applications

Under a Zone 4 partial deployment, we will need to enhance certain existing IT systems and/or develop new ones. Figure 4-1 illustrates the conceptual system architecture that will be required for partial deployment.

Figure 4-1
Partial Deployment IT Systems Architecture



The systems that need to be developed or enhanced to support partial 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.

a) <u>Meter Supply Chain Management</u>

We will need to make changes to the Meter Supply Chain (MSC) system so that the following procurement processes can be automated under partial deployment:

- 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 Centers for installation.

Each pallet of meters received from the vendor will be equipped with Radio Frequency Identification (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 unit identifiers 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 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 below, to pass meter delivery information automatically to the service centers. Further, MSC system will interface with SCE's general ledger system to record new and retired asset information as meters are replaced and installed during partial deployment.

b) <u>Meter Change Workflow Systems</u>

As shown in Figure 1 above, a number of new IT systems will be needed to handle the meter change workflow in the areas of:

- New Meter Identification;
- Meter Changes Order Scheduling;
- AMI Installation;

- Meter Order Consolidation; and
- Meter Process Automation.

First, a new system will be needed to identify the meters that that will require a change to the new AMI metering. This application will be able to identify the sites where AMI meters need to be installed. The application will interface with the MSC system to identify the exact meters to be installed at a particular site.

In addition, partial deployment will require development of a new system 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 a full or partial deployment. Therefore, a new system will be required to handle the significant volume of meter changes associated with partial deployment. The new Scheduling Meter Change (SMC) system will need to interface with the new AMI Route Management system that verifies meter readiness for AMI integration. The SMC also automates the switching to the AMI network. It will need to interface with the current Customer Data Acquisition Management system which maintains 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 field inspections) related to AMI meter installation. This system will have the ability to issue and cancel orders, and to schedule appointments or reprioritize orders as field conditions warrant.

A Zone 4 partial deployment will also require a new system to handle the collection of necessary meter information to properly route the meter installation request to the field personnel installing the AMI meter. The AMI Installation (AMI-I) system will provide field personnel with the route information necessary to locate the meters that will be changed. As meter removals and installations are completed by field personnel, the AMI-I system will process completion information, including Global Positioning Satellite (GPS) data, and deliver it to the Meter Inventory system for further processing.

The AMI-I system will also interface with the SMC system to reschedule incomplete orders. The system will also identify 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 Field Tool system. Accordingly, users of the Field Tool will have the capability to view orders and input completion information. The Field Tool will also allow users to cancel or refer orders, if appropriate.

Under a Zone 4 partial deployment, a new system is required to interface with the existing MPA system (which currently schedule, track and post data on meter orders). The Order Consolidation (OC) system will be developed to examine and consolidate various meter orders for the same installed service account. This will maximize operational efficiency.

To accommodate a Zone 4 partial deployment, we expect to enhance the existing MPA system used to schedule, track, and post data related to meter orders. Enhancements are necessary because the current MPA system is not capable of managing the meter volumes expected in partial deployment. One required enhancement will be an interface to the new AMI-I system that will provide a link between the existing and new systems. In addition, enhancements are required so that the MPA system can store GPS data returned from the field to facilitate meter location tracking.

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

As shown in Figure 4-1 above, under a Zone 4 partial deployment, a number of new systems need to be developed to handle the AMI process. Additionally, enhancements to existing meter-related systems are required.

As a result of partial deployment, 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. For partial deployment, 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 can input interval data usage in situations where the data is not available for certain periods of time. Another example of a required change to the AM system involves changing the data validations and prorating algorithms to handle interval data usage.

We also expect to modify the current Field Order Dispatch (FOD) system to accommodate partial deployment. The FOD system is currently responsible for the management of field visits related to metering and communications incidents that may include error detection, failures, and replacements. Modification of this system will need to be developed to route field events from FOD to the AMI communications network support group and meter support groups.

A Zone 4 partial deployment will also require development of a new system to monitor the status of accounts on each of the routes. This system will determine when all of the installed AMI meters on a particular route are communicating with the network. Once the new AMI Route Management system has validated that all newly installed AMI meters on a route are successfully communicating with the network, the route can then be switched to an AMI route.

We expect partial deployment to require a new system 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.

Under a Zone 4 partial deployment, a new system is needed to collect meter read information from the 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 partial 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 communications network through an electronic file. In addition, modifications 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 modified systems represented in Figure 4-1 requires computing services infrastructure to support the software handling the partial deployment AMI data. Computing Services includes the actual procurement and installation of necessary infrastructure. Computing Services infrastructure and hardware fall into the following broad areas:

- Additional servers;
- Additional processors to increase MIPS on the mainframe;
- Additional processors to increase processing capacity on RISC and Wintel systems;
- RFID tag reading equipment;

- 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.

D. Customer Service Systems Category

This section describes the operations, processes, and systems affected by partial AMI deployment. These are needed to provide an adequate level of customer services essential to the efficient installation and operations of a Zone 4 partial deployment of the AMI infrastructure and to assure a continued high level of services throughout the installation phase. Specifically, the customer services discussed in this section include Billing, Call Center, Meter Order Processing, and Customer Communications (Marketing) activities. This section will not include meter reading and field services costs, because these functions are essential to the Meter System Installation and Maintenance costs discussed in prior sections.

1. Description of Billing Activities Impacted by Partial Deployment

SCE's Billing Organization currently processes and delivers over fifty-six million customer billing statements a year. For the most part, this process is highly 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 and rate structure changes, both of which play a significant role in the partial deployment of AMI. Under the partial deployment scenario, we expect that we will need to supplement the existing billing system, that depends primarily on manual reads in the field, with a system that can generate a bill based on the AMI data transmitted through the network communications infrastructure. Billing Operations will also be affected by the incremental replacement of an additional 195,000 meters throughout the sixteen-year analysis period. These meters will be replaced because of anticipated AMI meter/communication failures (*see* Table 4-1 above).

Under the partial deployment Operational-Only case we assume that we will read the vast majority of meters remotely only once per month and that there is no need for interval data beyond that being collected today. Accordingly, processes associated with aggregating, validating, and processing interval data are not affected by the partial deployment Operational-Only scenario. As will be seen, the processing of interval data in several of the other scenarios has a significant impact on billing costs. This will be particularly evident in the demand-response scenarios where the majority of Zone 4 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 fifteen-minute or hourly read. For the Operational-Only case, we expect the need for approximately thirty-four FTEs in 2006 and 2007, dropping down to fourteen by 2010 as installations are complete and meter failure rates decrease to a steady rate of two percent per year. For the demand response cases, these numbers increase significantly, going from approximately thirty-eight to forty FTEs (depending on the scenario), and dropping to approximately fifteen as operations reach a steady state.

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. The largest partial deployment impact on the Billing Organization's operations and processes occurs during the installation phase and, as previously discussed, is attributable to 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. Though small in terms of percentage of the total, the initial replacement of nearly 500,000 meters will result in a significant increase in the number of billing exceptions being processed.

A major contributor to the increased exception processing is the anticipated failure rate of AMI meters we expect will occur in the initial stages of partial deployment. 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. This process becomes considerably more complex when 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.

We estimate that fifty percent of all meter failures will require exception processing within the Billing Organization. Meter failures are expected to peak at 43,000 in 2007, and drop below 8,700 by 2011. We expect that beyond the initial installation phase, meter failures will continue at a steady state rate of approximately two percent throughout the meters' useful service lives.

Another contributing factor to billing installation impacts is related to the development of new validation routines to replace the validations that currently take place in the field as meters are being read manually. Reading meters remotely adds a whole new layer of data quality concerns, not only attributable to new meter technology, but to the likelihood of communication system failures which will inevitably occur. This assessment is based on our experience with the recent implementation of RTEM, as well as our earlier experience with deployment of 350,000 van-based AMR meters.

Overall, under partial deployment, we expect a slight improvement in metering accuracy. We also expect higher meter failure rates and the loss of field validations.

2. Description of Call Center Activities Affected by Partial AMI Deployment

Our Call Center receives and handles over eleven million calls per year. Partial deployment of AMI is expected to result in call volume increases ranging from a low of approximately 20,000 calls for the initial year of the Operational-Only scenario to a high of approximately 245,000 calls during the peak installation phase for certain demand response scenarios. The call volume increases result from customers calling to inquire about the new meter that has been installed to questions about opting out of the new rate in the demand response partial deployment scenarios. For analytical purposes, the 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 choose to stay on the new rate. In determining the effects of partial deployment on Call Center, we estimated that seventy percent of calling customers would actually opt out. This estimate is based on our assumption that most customers calling to opt out will already have made up their minds. However, with proper training of Call Center personnel, we feel we should be able to convince thirty percent of such callers to continue the program.

We expect that as AMI is deployed and more accurate billing will result in call volume reduction. Billing inquiries today are received for several reasons, one of which is inaccurate meter reads. Based on a study using 2003 data, 22,791 calls were the result of meter reading errors. We used this number as a percentage of all calls to determine the percent of Zone 4 billing inquiry calls we could expect as a result of meter read errors. For the business case, we assumed that 100 percent of these Zone 4 calls would be avoided with automated meter reads. Ultimately, we expect call volume to be reduced by approximately 2,200 calls per year for all partial deployment scenarios.

E. Management and Miscellaneous Other

This section describes the overall Project Management and miscellaneous "other" costs not identified in the other cost categories. Other costs include centralized training costs, personnel recruiting costs, employee communications, and miscellaneous start-up costs. For the most part, these costs fall into the "start-up" and "installation" categories. The Billing Organization has identified some on going O&M management costs that are expected to continue through the duration of the analysis period.

1. Program Management

For the partial deployment scenarios, 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 ten 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 Ruling, with deployment starting in 2006, there will likely be project planning tasks that should occur in 2005. However, the 2005 Program Management costs are not included in this analysis.

2. Training Costs

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 for specialized instruction related to AMI metering activities and new rate options as well as for more generalized, new-employee training. Our JST training includes the cost of curriculum development, preparation of training materials, and payment of the instructors. JST training is primarily for new employees in the Meter Reading, Call Center, and Billing Organizations that will be needed to meet the added workload during the installation phase of AMI. These costs do not include the employee compensation 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

Under the "Operational-Only" partial deployment scenarios, we expect only a minimum level of direct customer communications costs beyond what we currently experience. We are required to notify customers of planned meter changes and we expect to comply through a regular monthly bill insert or bill message. Any mass media or other outbound communications that the Commission may feel is needed for purposes of public notification under the Operational-Only scenario would add incrementally to our estimated costs.

The costs associated with the addition of demand response options under the partial deployment scenario will differ based on scenario, but the basic structure and approach to the media and information delivery campaign will be similar. The campaign's strategic approach is to utilize an integrated mix of media designed to affect long-term cultural and behavioral change. To do this, the campaign must be multi-year. There are three tenets of the campaign: 1) raise awareness and educate customers about the program and its benefits as well as the behavioral changes required to comply with each specific demand response option; 2) develop and implement a strong and comprehensive acquisition effort to recruit customers and meet participation rate expectations; and 3) develop and implement a vigorous retention campaign to maintain the customer base over time. The media mix we envision for the campaign includes:

- Mass Media: television, radio, and print for education and awareness;
- Targeted/Ethnic Media: local print, cable television, and strategic partnerships (ethnic business chamber promotion) including the use of in-language media;
- Direct Communications: bill inserts, direct mail, e-mail notification, face-to-face communication through the account management function; and
- "CPP Day" Notification: use of phone banks, radio, public service announcements, and press releases/press relations to notify customers of demand response events.

Each cost category includes a basic level of communication and outreach designed to reach 100 percent of our Zone 4 customers and saturate the customer base with broad-based educational and customer-specific behavioral change information. Additionally, each partial deployment demand response scenario will require extensive research to understand consumer attitudes and to adapt messaging appropriately for all geographic and ethnic groups prior to the start of the campaign.

The campaign will differ significantly from prior SCE campaigns, which are designed to create customer awareness and promote programs on a short-term basis. This campaign will create customer awareness and education about behavioral changes required to comply with the chosen demand response option. Customer adoption of long-term behavioral and cultural change is essential to the program's success. Accordingly, one of the campaign's two main objectives is to teach customers why demand response requires a behavioral change and then move them toward appropriate behavior modification. Through education, we expect to teach customers about the effects of their energy usage and the impact of time-differentiated pricing options on their overall costs. This will be achieved through the customer-specific education portions of the campaign. The second campaign objective is to recruit and retain customers to these demand response rate programs over time. This will be accomplished through the customer-specific acquisition and retention portions of the campaign.

The cost of the campaign is affected by our location and the customer base we serve. The greater Los Angeles area is the second largest and highest cost media market in the country, and is both linguistically and culturally diverse.[7] Because of this diversity, messages must be created and delivered in languages other than English. Additionally, thirty-five percent of SCE's customer base has demonstrated a lack of interest in electricity issues other than specific power outages.[8] Customer communications must break through this demonstrated low

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[7] 2003 – 2004 Nielson Universe Estimates, DMA Ranking and Advertising Age Magazine, July 24, 2000.

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

level of interest and do so through a variety of linguistically and culturally appropriate approaches which properly address various Asian, Spanish-speaking, and African American communities, as well as the general population.

4. Other Costs

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

III.

PARTIAL AMI DEPLOYMENT BUSINESS CASE ANALYSIS FOR >200 KW CUSTOMERS

The Ruling requires the analysis of large commercial and industrial customers (>200 kW of demand) placed on default two-part real-time tariff, with the option of switching back to their currently applicable TOU tariff. We considered this scenario, but provide an alternate approach for the following reasons.

First, by memo dated August 6, 2004, Agency staff acknowledged that a two-part RTP rate for California utilities has not been developed and, as an alternative, suggested that utility analysts use data provided in findings from two reports on RTP tariffs, one from a study in Georgia and the other from a study in New York. We used the study from Georgia by Christenson Associates[9] as the basis for estimating demand response from RTP segmented by Standard Industrial Classification (SIC) code. Our approach for estimating the demand response for RTP using this study is explained in Volume 2 of this filing.

Second, we have no reasonable data available for estimating the opt-out percentage that would result from the implementation of the RTP tariff on a default basis. The largest customers in this group are relatively sophisticated and will evaluate and affirmatively choose whichever rate is most beneficial to them. Hence, implementation of the RTP tariff on a default basis may not be as effective for this customer class as it would be for smaller customers. Alternatively, for purposes of this analysis, we assume that RTP would be implemented on a mandatory basis. This assumption provides the maximum customer participation and highest demand response benefit.

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[9] "Potential Impact of Real Time Pricing in California," by Steve Braithwait and David Armstrong, Christensen Associates, January 14, 2004.

We made additional adjustments to the study of large customers placed on an RTP tariff. The Ruling required that the large customer analysis be combined with Scenarios 4 and 7, but we have kept the analysis as a separate scenario so it could be added to any of the full or partial AMI deployment scenarios. Moreover, we analyzed two variations of RTP deployment. In Scenario 12, we assume that all large customers with RTEM meters are placed on a RTP rate on a mandatory basis. For Scenario 13, we assume 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.

A. Operational Costs

For Scenarios 12 and 13, we expect to incur certain information technology infrastructure costs that we have preliminarily estimated at $300,000 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. We will continue to refine our preliminary estimates for the costs and reflect these refinements in our final showing as appropriate.

As shown below in Table 4-2, the only difference between Scenarios 12 and 13 pertains to expected customer acquisition costs for the rate incentives that would be paid to Rate Schedule I-6 customers. For this preliminary analysis, we forecast costs of approximately $355.5 million. We will continue to refine this preliminary estimate and will reflect changes in our final showing, as appropriate.

Table 4-2 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

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 as presented in Volume 2, Appendix C. A distribution loss factor of 8.4 percent was applied to energy and capacity benefits.

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. Our methodology for estimating demand reductions for these scenarios is discussed in Volume 2.

Table 4-3 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, RTP Customers	$224	$113
Demand Response Benefit DR-1, Schedule I-6 Customers	n/a	$330
Demand Response Benefit DR-2	$31	$61
TOTAL:	$255	$504

C. Uncertainty and Risk Analysis

No risk analysis of cost or operational benefit was performed for Scenarios 12 and 13 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. The literature indicates that, while some large customers can adjust usage, others cannot.

D. Net Present Value Analysis

Table 4-4 summarizes the Net Present Analysis for Scenario 12.

Table 4-4 Summary of Cost/Benefit Analysis for Scenario 12 ($Millions)				
Costs	**Benefits**	**Pre-tax PV**	**After Tax NPV**	**Rev. Req. NPV**
$17.9	$255.3	$237.4	141.0	$237.1

Table 4-5 Summary of Cost/Benefit Analysis for Scenario 13 ($Millions)				
Costs	**Benefits**	**Pre-tax PV**	**After Tax NPV**	**Rev. Req. NPV**
$373.3	$504.0	$130.7	$77.6	$126.2

As shown in Tables 4-4 and 4-5, analysis of Scenarios 12 and 13 result in positive NPVs of $141.0 million and $77.6 million, respectively. These scenarios derive their positive value by obtaining demand response benefits with no incremental meter deployment costs.

IV.

PARTIAL AMI DEPLOYMENT BUSINESS CASE ANALYSIS FOR ZONE 4 OPTION

This section provides our second approach to partial AMI deployment to approximately 435,000 customers in climate Zone 4 as delineated in the SPP. Our objective in analyzing these partial deployment scenarios is to determine the best-case cost/benefit results by selecting a portion of our service territory where we can reasonably expect to realize the highest opportunity for load reduction and demand response capabilities and which is geographically situated so as to benefit from significant meter reading savings. Climate Zone 4 is the portion of our service territory that meets these two criteria. This zone covers Baseline Regions 14 and 15 of our service territory, which includes the Coachella Valley (including Palm Springs and surrounding resort communities). The primary reasons for adopting Zone 4 are discussed in Section II.

The following sections address the eight separate partial deployment scenarios required by the Ruling. Table 4-6 below identifies the partial deployment scenarios for which we are providing this revised business case analysis.

Table 4-6 Listing of Partial Deployment (Zone 4) Scenarios	
Scenario No.	Description
14	Partial AMI: Climate Zone (Zone 4) - operational only case
15	Same as Scenario 14 except includes outsourcing
16	Partial AMI: Zone 4 – TOU tariff is default
17	Partial AMI: Zone 4 – CPP-F tariff is default for residential, CPP-V default for small C&I, no large C&I customers included
18	Partial AMI: Zone 4 – Current tariff with opt-in to CPP-Pure tariff (residential and small C&I)
19	Partial AMI: Zone 4 – Current tariff with opt-in to CPP-F residential/CPP-V small C&I
20	Partial AMI: Zone 4 – Current tariff with opt-in to CPP Pure
21	Partial AMI: Zone 4 – Current tariff with opt-in to CPP-F residential/CPP-V small C&I
22	Removed from the October 22, 2004 preliminary analysis
23	Removed from the October 22, 2004 preliminary analysis

The following subsections describe the costs and benefits we expect to result from implementation of each scenario. These costs and benefits are described as "incremental" to our "Business As Usual" case, as presented in Section II(B) of Volume 2. "Partial Deployment" means replacing ninety-seven percent of the 449,000 existing Zone 4 meters over a two-year time period, and building the communications infrastructure to allow automatic reading of seventy percent of these meters.

A. Scenario 14: Operational Only - Utility Implemented

In this subsection we describe the operational costs and benefits expected to result from partial deployment to Zone 4 by SCE of the AMI metering and communications infrastructure. These costs and benefits are quantified using the Ruling's 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 net present value analysis. As required by the Ruling, "this scenario assumes that no new tariffs are established as a result of the full deployment of AMI, so costs and benefits that derive from the rollout of new tariffs are excluded in this case."[10] The operational activities processes and procedures affected by full deployment under this particular scenario were fully discussed in Section II, above.

1. Costs

Appendix A of the 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 4-7, below, summarizes our estimated costs for Scenario 14 in the five applicable cost categories.

Table 4-7
Summary of Costs for Scenario 14
(000s in 2004 Pre-Tax Present Value Dollars)

Cost Categories	Total
Metering System Infrastructure	$73,522
Communications Infrastructure	4,767
Information Technology Infrastructure	59,039
Customer Service Systems	8,125
Management and Miscellaneous Other	12,461
TOTAL:	$157,915

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

[10] Ruling, Attachment A, p. 7.

a) Meter System Installation and Maintenance

(1) Start-up and Design

Appendix A to the Ruling does not identify any cost codes for meter system start-up or design. As such, all Meter System start-up or design activities have been classified as an installation cost below.

(2) Installation and Maintenance [MS-1 through MS-11]

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)

Residential and Small Commercial (< 20 kW) Meters

We are assuming that our current field services representatives and meter readers will be selected for the Project Temporary Installer positions, as discussed further in cost category MS-5. At the start of 2006, we estimate that we will have seventy-eight vacancies in our meter reading staff caused by employee movement to other areas to support AMI deployment. We plan to fill those vacancies in early 2006.

As discussed in Scenario 1, when filling these positions, we have taken into account the productivity differential between a new meter reader and an experienced meter reader. As such, in addition to the seventy-eight vacancies that will be filled, we will need to hire an additional twenty-two project temporary meter readers in 2006. The anticipated cost is $2.89 million in 2006.

For the meters in Zone 4 that are handled by our rural service center personnel, we will rely on our existing Field Service Representatives (FSRs) to handle the 75,640 installations. Existing meter readers will be upgraded and trained to handle the FSR job responsibilities to backfill for the FSRs taking the project temporary installers positions. We plan to backfill the vacancies in our meter reading staff with project temporary meter readers. We estimate that we will need eighteen meter readers in 2006. The anticipated cost is $0.99 million in 2006.

(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 an additional supervisor and 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 ten incremental FTEs are estimated to cost $0.93 million.

(c) Cost of Purchasing Meters (MS-3)

Our preliminary estimate is that we will procure approximately 655,000 meters at a cost of $43.9 million over the 2006 to 2021 timeframe. We will procure five different meter types for the AMI deployment. Each meter will be equipped with an RFID tag to facilitate our procurement and supply chain processes. Sales tax was added to the meter cost.

We will procure over 435,000 meters in order to replace the existing meters installed in the Zone 4 area. Table 4-8 shows the types of meters, quantities, and prices that will be procured for partial deployment.

Table 4-8
Meters, Quantities and Prices in Partial Deployment

Meter Type With Communication Module	Amount	Base Cost	RFID Cost
< 20 kW residential single phase	406,000	$50	$2
< 20 kW network	3,000	$130	$2
< 20 kW 3-phase commercial & residential	16,000	$320	$2
> 20 kW commercial	10,000	$700	$2
	435,000		

As discussed in Scenario 1, in addition to the cost estimates in Table 4-8, we will incur additional costs for meter lock rings and adapters.

Our preliminary analysis shows that during the partial deployment, we will have meters that fail after the three-year warranty period has expired. We estimate that there will be approximately 109,000 meter failures during the 2009 to 2021 timeframe based on our projected failure rate.[11] In those cases, we will need to procure and install new AMI meters at these meter sites. Table 4-9 illustrates the expected meter type and volumes associated with replacing these failed meters.

[11] *See* Volume 2, Section III concerning how this failure rate was calculated.

Table 4-9 Cost Table for Meter Failures Out of Warranty Purchases Only 2009 Through 2021	
Meter Type With Communication Module	**Quantity**
< 20 kW single phase	102,000
< 20 kW 3 phase commercial & residential network	1,000
< 20 kW commercial	4,000
> 20 kW commercial	2,000
TOTAL	109,000

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 0.11 million new meter sets during the 2006 to 2021 timeframe due to customer growth. Table 4-10 shows the expected meter type and volumes associated with these new meter sets.

Table 4-10 Cost Table for Growth Meter Purchases Only 2006 Through 2021	
Meter Type With Communication Module	**Quantity**
< 20 kW single phase	104,000
< 20 kW network	1,000
< 20 kW 3-phase commercial & residential	4,000
> 20 kW commercial	2,000
TOTAL	111,000

(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 $2.4 million for installation equipment and facility costs.

While Scenario 1 contained costs related to reconfiguring our meter testing equipment, in a partial deployment, we would be able to take advantage of our existing equipment without incurring any incremental reconfiguration costs.

(e) Installation Labor (MS-5)

(i) 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 343,000 meters. We project the need for sixty-three project temporary installers during 2006.[12] The cost for the additional personnel to perform installations is estimated to be $4.6 million in 2006.

(ii) Complex Meters

To meet the partial deployment schedule, we estimate that additional personnel will be needed to install approximately 20,000 meters. While we rely on both full-time and contract resources in Scenario 1, we are solely utilizing full-time resources in the Zone 4 partial deployment. In 2006, we will dedicate thirty Meter Technicians to these installations. These resources will also need to work overtime. We have estimated that the overtime that will be worked is equivalent to one incremental full-time employee in 2006.[13] The cost for the additional personnel is estimated to be $2.6 million in 2006.

[12] As in Scenario 1, we base this estimate on the assumption that an installer will install twenty-five residential meters per day or eighteen commercial/industrial meters per day. Installation rates for the meters covered by Rurals are different because of the vast difference in geographic locations between meters. They are twenty residential meters per day and five commercial/industrial meters per day.

[13] As in Scenario 1, we based these estimates on the assumption that a Meter Technician can install an AMI meter in 2.5 hours on average.

(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 $148,000 in 2006.

(g) Panel Reconfiguration/Replacement (MS-7)

As described in Scenario 1, for the purposes of this preliminary business case analysis, we relied on our experience to develop a per meter damage cost estimate of $0.14. Overall, the costs associated with these activities are estimated to be $61,000 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 preliminary 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)

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. While we did estimate incremental labor costs for this activity in Scenario 1, we are assuming that we will be able to absorb this work with our existing staff in Scenario 14.

(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 five 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 one heavy transportation driver 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 personnel to supervise the additional FTEs as well as project support personnel to provide forecasts to suppliers and to expedite and track purchases. Throughout the 2007 to 2020 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 2020. We estimate the cost for the additional personnel at $1.92 million over the 2006 to 2020 timeframe.

Currently our central distribution facility is at ninety-five percent capacity, maintaining a monthly average of 25,000 meters new business and system integrity. With a partial AMI deployment, we expect to increase our meter inventory by 20,000 meters monthly. Since the facility will need to accommodate both the new AMI meters as well as meters for the non-Zone 4 customers, a new facility is required through first quarter of 2007 to house the meter inventory because our current facility cannot accommodate the volume of meters required for this deployment.[14] Other non-labor costs that we will incur from 2006 to 2020 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 $1.84 million over the 2006 to 2020 timeframe.

As the meters are delivered to the 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 three additional employees to handle these activities at an estimated cost of $0.23 million in 2006.

A critical assumption in our supply chain management analysis is that we will be utilizing RFID technology to facilitate the meter deployment processes. While this technology is being used in various industries, it is a new technology for us and we will plan to engage consultants with experience in this area to assist with the implementation. We estimate a cost of $0.66 million in 2006 for these activities. Our estimate is based on cost information received from a potential vendor of these services.

(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

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

personnel will be $1.19 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 Organization estimates training costs of approximately $0.57 million. As mentioned in cost code MS-10, our current central distribution facility is at ninety-five 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 $0.54 million in costs in 2006 to make this facility operational.

While we were able to avoid severance-related costs for our rural service center personnel in Scenario 1, we will not be able to avoid these costs in this partial deployment scenario. We will have eleven additional meter readers on staff after the deployment is completed. These employees will need to go through a severance process. The costs associated with this process have been captured in this cost category and are estimated to be approximately $0.76 million.

(3) Operation and Maintenance [MS-12 through MS-14]

(a) Maintaining Existing Metering Systems (MS-12)

As meter failures occur throughout the deployment period and beyond, 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 to 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.

Currently, 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 $4.9 million for the 2006 to 2021 timeframe. We will also incur $0.76 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 200 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 $38,000.

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 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.

(b) 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 $0.60 million over the 2006 to 2021 timeframe.[15] Non-labor costs of $0.14 million will be incurred for tools, equipment, materials, supplies, uniforms and vehicle costs associated with these new meter readers.

(c) 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 200 kW commercial accounts. While we did estimate incremental labor costs for this replacement activity in Scenario 1, we are assuming that we will be able to absorb this work with our existing Meter Technician workforce in Scenario 14.

In addition to the labor costs described in MS-12, we will also incur equipment costs of approximately $56,000 for tools, equipment, materials, supplies, uniforms and vehicle costs associated with the additional personnel handling meter replacements.

[15] As in Scenario 1, our personnel estimates are based upon a pick-up read rate of fifty-six reads per day.

b) Communications Infrastructure

(1) Start-up and Design (C-1 through C-5)

(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 $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 $100,000.

(b) Network Placement Site Surveys (C-2)

As in Scenario 1, 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) 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 928 collectors, ten packet routers, and eighteen MCC take-out points is approximately 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 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 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) Review/Develop Strategies to Retrieve/ Process Data from Meters (C-5)

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 needed to develop new applications or, in some cases, enhance existing applications to handle these requirements. Section II 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 $0.2 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 $0.63 million in project management and business analyst support labor costs for these activities over the 2006 to 2008 timeframe.

(2) Installation (C-6 through C-11)

(a) 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 various 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, we will provide the contractor personnel, who handle the equipment in the field, 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.[16] 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 $0.85 million over the 2006 to 2021 timeframe.

(b) Pole Replacement (C-7)

As in Scenario 1, there will not be any pole replacements required to support the partial deployment to Zone 4.

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

As in Scenario 1, there are no incremental costs associated with this cost category.

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

As in Scenario 1, there are no incremental costs associated with this cost category.

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[16] As discussed in Scenario 1, we assumed 1% 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.

(e) 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 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 thus will not possess remote read capability.

The cost estimates for cost category C-10 also include the equipment costs associated with ten 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 eighteen 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.[17]

Table 4-11 describes the annual deployment volumes associated with the communication infrastructure.

Table 4-11
Communications Infrastructure Deployment Volumes

Equipment	2006	2007	2008
Collectors	515	310	103
Packet Routers	7	3	0
MCCs	12	6	0

[17] 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.

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.[18]

The estimated costs associated with this cost category are $1.4 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.

(f) WAN/LAN Training (C-11)

As in Scenario 1, there are no incremental costs associated with the training for the installation of WAN/LAN equipment.

(3) Operation and Maintenance [C-12 through C-15]

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

As in Scenario 1, there are no incremental costs associated with this cost category.

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

As in Scenario 1, there are no contracts required to retrieve the meter data and services.

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[18] As in Scenario 1, we have assumed an annual failure rate of one half of one percent.

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

As in Scenario 1, there are no dispatch and O&M costs associated with infrastructure equipment.

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

As in Scenario 1, there are no incremental costs associated with this cost category.

c) Information Technology Infrastructure

(1) Start-up and Design (I-1)

(a) Network Planning/Engineering (I-1)

As discussed above, 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.

(2) Installation (I-2 through I-7)

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

Our computing systems will need to be enhanced in order to support AMI. As previously discussed, we will develop new applications and enhance existing applications. To accommodate these applications, new hardware and operating systems, including fifty-eight servers and 1,640 Gb storage, will need to be procured to supplement SCE's existing computing infrastructure.

As described in Scenario 1, in support of meter inventory management, we are planning to utilize RFID technology. Since SCE has not used this technology previously, we will need to acquire the equipment to make this technology operational. The equipment we will procure includes dock door portals, barcode readers, hand-held readers and laptops. 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 charges for the computing systems and associated labor are estimated to cost $6.4 million.

(b) Data Center Facilities (I-3)

No new data center facilities are required.

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

As discussed in Section II, we will be enhancing existing and developing new applications and enhancing existing 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 $25,000.

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

As discussed previously, we will make changes to our Meter Supply Chain system to automate our procurement processes. For the Meter Supply Chain application cost estimate, a critical assumption for this business case is that the Supply Chain project described in the 2006 GRC is deemed reasonable and receives cost recovery.[19] The major cost drivers of the changes needed to the Meter Supply Chain System include Supply Chain software enhancements and configuration for meter procurement process; software support for RFID additional software enhancements to support changes in the procurement process due to meter volume and deployment schedule; and integration with other systems in the meter deployment workflow. The Meter Supply Chain application described in the 2006 GRC will require substantial configuration to enable the embedded modules to support the business requirements for AMI meters. Additionally, these enabled modules will require integration with several 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. We estimate the system configuration, related business process change management, and significant software upgrades will cost $11.5 million over the 2006 to 2021 timeframe.

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[19] *See* SCE's 2006 GRC Application A.04-12-014 submitted 12/21/04.

(e) 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 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 $0.53 million over the 2006 to 2007 timeframe.

(f) 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 $12,000.

(3) Operation and Maintenance (I-8 through I-16)

(a) Maintain Existing Hardware/Software that Translates Meter Reads 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 $20,000.

(b) Process Bill Determinant Data (I-9)

As usage data is collected and processed, we expect that additional customer service representatives will be needed to manually process accounts that the system is unable to process due to usage validation failures. Our personnel estimates of $4.3 million include the costs for 11.0 FTEs in 2006, 11.3 FTEs in 2007, and then steadily decreasing to reach a steady state of 3.1 FTEs from 2011 to 2021.

In terms of our IT systems, we will also need to dedicate resources to defining 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 2006. We estimate the cost for these activities is $52,000.

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

As in Scenario 1, there are no incremental contract administration costs and the costs associated with infrastructure database management are included in I-16.

(d) Exception Processing (I-11)

As meter failures occur, we expect that 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 fifty percent will require manual processing. 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 $2.4 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 ten 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 $62,000.

(e) 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 cost includes an initial software license fee in 2006 and aggregate ongoing license fees for a total of $3.9 million during 2006 to 2021.

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

As in Scenario 1, there are no incremental ongoing data storage/handling costs due to similar data capacity requirements in the "Business As Usual" case.

(g) Ongoing IT Systems (I-14)

As discussed in Section II, 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. 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 $9.9 million during the 2006 to 2021 timeframe.

(h) Operating Costs (I-15)

Once the communications infrastructure is fully operational, it will contain nearly 16,000 commercial meters with radios, 928 collectors, ten packet routers, and eighteen MCC take-out points. As the infrastructure is developed, we will need to phase in eight incremental full-time employees 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 twenty engineers and IT specialists for every 40,000 radios. The incremental labor costs from 2006 to 2021 are $9.6 million.

(i) 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. As in Scenario 1, 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 $8.2 million.

d) Customer Service Systems

This section will describe the Customer Services, related cost codes utilized in assigning costs for the Partial Deployment "Operational-Only" scenario (Scenario 14). For our purposes, Customer Services include Call Center costs, Meter Order Processing, Customer Communications, and a portion of billing related costs.[20] We expect to spend approximately $8.1 million in these 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 1.(a) above.

(1) Start-up and Design

Appendix A of the 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 four FTEs in 2006. 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.

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[20] The majority of billing system installation and operating costs are included in the Information Technology section (Section 1.(c) above) because cost codes I-9 and I-11 better described the billing related functions of "validating and creating billing determinate data" and "Exception Processing."

(2) 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.

(a) 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 \$5.0 million over the duration of the analysis period. 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 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 forty-four FTEs in the initial year of implementation (2006), and will drop off to three FTEs in 2007, two in 2008, one in 2009, and none thereafter, *i.e.*, no incremental cost once the installations are complete. Total meter order processing costs over the duration of the analysis period are expected to be \$3.3 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 $1.6 million for these activities over the 2006 to 2021 timeframe.

(b) Increased Call Center Activity During Installation Phase of the Partial Deployment "Operational-Only" Case (CU-2)

Call center impacts are expected to be minimal for the Operational-Only case, totaling $99,000 through 2021. We expect a relatively small volume of calls will result from media messages introducing the change 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. Call volume during the installation phase of this Operational-Only scenario is expected to reach 20,000 additional calls in 2006, dropping to zero by 2007. This call volume would require the addition of 1.62 FTEs during the peak installation stage.

(c) 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 minor IT costs ($22,000), we have not identified any other incremental implementation costs related to OMS.

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

The Meter Services Organization expects to incur costs of approximately $2.7 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. In addition, the Billing Organization expects to spend $202,000 in this cost code, all in 2006. This is for exception processing work directly related to meter changes during the installation phase.

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

Only cost code CU-5 has the potential to be affected in this Operational-Only scenario. Even though there would be no new rates introduced under this scenario, we expect some 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. This results in a total cost of $172,000 through 2021 in cost code CU-5. 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 those two cost codes. Cost code CU-8, CU-9 and CU-10 have to do with rate changes, interval data and customer communications. These three cost codes are not applicable to the Operational-Only scenario and will be described and accounted for in Scenario 3 through 8.

e) 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.

(1) Start-up and Design Costs (M-1 and M-2)

(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. (*See* explanation for this cost code in Scenario 1, in Volume 3, Section A.1.e.)

(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.

(2) Installation Costs (M-3 through M-11)

(a) Customers' Access to Usage Information (M-3)

Because this scenario is "Operational-Only" we will not be collecting interval data and have not included any costs related to increased support of customer requests for more detailed usage information.

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

The Billing Organization has included a total of $303,000 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.

(c) 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 JST. 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 $346,000 for the duration of the analysis period through 2021. Billing Organization training costs in this cost code are expected to be $266,000 for the same period.

(d) Meter Reader Reroute Administration (M-6)

The cost of recycling and rerouting the thirty percent 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 three additional supervising FSRs assigned to each of the three major districts to supervise the AMI meter system installation process.

(e) 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 installation phase of this scenario is only one year as opposed to five years for the full deployment case. For the partial deployment scenarios, 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 $6.6 million. We have also determined that in order to meet the deployment schedule proposed in the Ruling, with deployment starting in 2006, there will likely be project planning tasks that should occur in 2005. However, since the Ruling directed the business cases to start in 2006, the 2005 costs are not included in this analysis.

(f) 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.

(g) 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.

(h) 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 $400,000 will be spent training Call Center, Field Services and Meter Reading personnel under cost code M-10.

(i) 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.

(3) Operation and Maintenance [M-12 through M-14]

Capital and financing costs (M-12) are included in the NPV calculations at SCE's long-term weighted average cost of capital. Alternative methods of financing are discussed in the outsourcing scenarios (Scenarios 2 and 15). There is no change in the cost associated with mid and off-peak loads (M-13) under this scenario. Customer acquisition and marketing costs (M-14) will be discussed in the demand response scenarios and do not apply to the Operational-Only scenario.

2. Benefits

Table 4-12 summarizes the total estimated benefits we expect to result from the partial deployment of AMI in the Operational-Only case.

Table 4-12 Summary of Benefits for Scenario 14 (000s in 2004 Pre-Tax Present Value Dollars)	
Benefit Categories	**Total**
Systems Operations Benefits	$29,326
Customer Service Benefits	1,144
Management and Other Benefits	11,286
Demand Response	-0-
TOTAL:	$41,756

The following sections will describe only those benefit codes that were actually used in this preliminary analysis. Appendix A to this Volume contains a discussion of all benefit codes identified in the Ruling, whether we actually included them in this analysis or not.

a) 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 314,000 SCE customers in Zone 4. Appendix A of the Ruling identified thirteen 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 thirteen 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. One benefit code (SB-9) applies only to the full deployment demand response scenarios (Scenarios 3 through 18).

(1) 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 twenty-five 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 scenarios, we expect AMI to give us the ability to remotely read approximately seventy percent of all meters in Zone 4 (70% of 449,000 = 314,000). The remaining 135,000 meters, that cannot be read automatically, will continue to be read manually on a monthly basis by approximately twenty-nine meter readers.[21] 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.

(2) 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 benefit would result in a savings of approximately $2.8 million over the duration of the analysis period.

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[21] 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.

(3) Reduction in Energy Theft, Identifying Broken Meters, Wrong Multipliers, and Metered Accounts not Being Billed (SB-3)

No savings have been included (See Appendix A).

(4) 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 4-13 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 0.6 FTEs by 2007. This results in a total cost savings of $364,000 over the duration of the analysis period.

Table 4-13
Reduced Phone Calls – Partial Deployment

	2006	2007	2008	2009	2010	2011
Scenario 14	0	2,216	2,216	2,216	2,216	2,216

(5) Elimination of Rate Design Constraints Due to Meter Programming Limitations (SB-5)

No savings have been included (see Appendix A).

(6) Outage Management System (OMS) Benefits (SB-6)

No savings have been included (see Appendix A).

(7) Better Meter Functionality/Equipment Modernization (SB-7)

No savings have been included (see Appendix A).

(8) Remote Service Connect/Disconnect (SB-8)

No savings have been included (see Appendix A).

(9) Improved Meter Accuracy and More Timely Load Information (SB-9)

Savings have been included in the full deployment demand response scenarios only (see Appendix A).

(10) Distribution Planning and Design (SB-10)

No savings have been included (see Appendix A).

(11) Reduction in Unaccounted for Energy (UFE) (SB-11)

No savings have been included (see Appendix A).

(12) Self-Generation Monitoring (SB-12)

No savings have been included (see Appendix A).

(13) Reduction in the Amount of Time Required to Implement New Rates or Load Management Programs (SB-13)

No savings have been included (see Appendix A).

b) Customer Service Benefits (CB-1 through CB-13)

The Ruling identified thirteen "additional" customer service benefits, most of which relate to billing and demand-side management and most of which require the availability of interval load data, which does not apply to this Operational-Only scenario. Our review of these potential areas of benefit resulted in anticipated annual savings of approximately $1.1 million over the sixteen-year analysis period of the partial deployment "Operational-Only" scenario. This savings is all attributable to improved billing accuracy (CB-1) due to the elimination of estimated bills and timelier billing due to elimination of meter accessibility problems. Additional customer service benefits from benefit code CB-8 are being recognized in the demand response scenarios (Scenarios 16 through 21). For a discussion of all other Customer Service benefit codes as they relate to partial deployment of AMI, see Appendix A.

c) Management and Other Benefits (MB-1 through MB-10)

We expect to reduce costs by approximately $785,000 through 2021 by decommissioning twenty-five 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 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 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 (Volume 2, Section 2.B.3.c) 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 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 $10.5 million over the duration of the analysis period. .

The remaining areas of potential Management and Other benefits, as identified in the Ruling, are discussed in Appendix A.

3. Uncertainty and Risk Analysis

As discussed in Volume 2 and in accordance with Attachment A of the Ruling, we performed a risk assessment of the operational costs and benefits for the partial Zone 4 deployment scenarios that could result from uncertainty or lack of data. The risk analysis we performed for this scenario is based on the specific cost and benefit data discussed in the sections above.

For analytical purposes, this operational risk assessment focuses on those cost and benefit codes that have estimates (in cumulative nominal dollars (*i.e.* 2006-2021)) of $500,000 or greater. Once appropriate cost and benefit codes are identified, we develop the most likely high and most likely low ranges for each of the cost and benefit cost categories. Consistent with the Ruling, we then applied a Monte Carlo statistical approach to create a probabilistic range around our estimate. The results allowed us to determine the confidence levels of our estimates as well as a contingency value at a ninety percent confidence.

For Scenario 14, the total present value cost estimate for full AMI deployment is $157.9 million. Five cost codes in Scenario 14 represent over 50 per cent of the total cost for this scenario. The most significant cost code in Scenario 14 is MS-3 involving meter and meter-related communications equipment obtained from a single vendor. We estimated a range for this cost code at: plus twenty percent and minus five percent. 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 twenty 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. Our information technology computing systems lifecycle costs have a range of plus or minus forty percent due to the uncertainty of the data processing and storage required**.** Our software development costs ranged plus forty percent to minus fifty percent based on the uncertainty of the final design. The meter and field communication installation costs may vary by as much as plus fifteen percent to minus twenty percent based on installation productivity. Under this partial deployment scenario our Billing Organization estimate may vary in a range of plus twenty percent to minus fifteen percent depending on the number of exceptions processed.

The primary operational benefits relate to the reduction in meter readers and associated meter reading costs that result in aggregate savings of nearly $26 million. We do not expect any variation because the forecast reduction is solely a function of the AMI system communication coverage for Zone 4. The other identified operational savings were less than the $500,000 threshold we used for analytical purposes. As a result, we did not include any operational savings below this threshold in the statistical analysis.

Using the cost ranges estimated above, the application of the Monte Carlo statistical analysis of costs resulted in a range of $149.6 million to $175.7 million around the estimated cost of $157.9 million for this scenario. The statistical analysis indicates that our cost estimate has about a twenty-eight percent confidence. This means that the project has a seventy-two percent chance of overrunning. Our preliminary cost estimates do not include contingency. However, based on our analysis we should consider a contingency of approximately $7.7 million in our final application to reduce the risk of overrun. This contingency amount is the difference between our cost estimate and the value at the ninety percent confidence level.

4. Net Present Value Analysis

Table 4-14 summarizes the overall pre-tax costs and benefits of Scenario 14. Also shown is the after-tax NPV for these scenarios on a cash flow basis, and the present value of the revenue requirement over the sixteen-year analysis period

Table 4-14
Summary of Cost/Benefit Analysis for Scenario 14
($ Millions)

Costs	Benefits	Pre-tax Present Value	After-Tax NPV	Rev. Req. NPV
$157.9	$41.8	($116.2)	($80.2)	($173.2)

Scenario 14 results in a negative Revenue Requirement Present Value of $173.2 million and does not support the implementation of partial AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the scenario 1 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.

B. Scenario 15: Operational Only - Outsourced

The "full-deployment" outsourcing analysis was presented in Volume 3 as Scenario 2. In that section we provided an overview of SCE's general policy considerations regarding outsourcing and we described our approach to analyzing the available outsourcing options for both full and partial deployment of AMI. In this section, we will present the results of the outsourcing option as it relates to the partial deployment scenarios. We will not repeat the general discussion relating to matters that were common to the analysis of both full and partial deployment. All stated values in this scenario are in nominal 2004 dollars and no attempt has been made, at this time, to convert them to present-value dollars as were used in the other scenarios. Therefore, caution must be used in making direct comparisons to any of the other partial deployment scenarios presented in this volume.

1. Overview of Approach

a) Conclusions

Our analysis concludes that there is no potential economic value to outsourcing significant portions of the partial deployment case. Table 4-15 below summarizes the results of the three most viable outsource provider's cost estimates compared to SCE's cost estimates for the same partial-deployment scenario.

Table 4-15 Summary of Financial Analysis of Outsourcing Scenario Partial AMI Deployment					
	($000)				
	Service Provider				
Description	**A**	**B**	**C**	**Service Provider Average**	**SCE**
Installation Total	$ 104,157	$ 117,875	$ 221,033	$ 147,688	$ 212,725
O&M Total	$ 484,698	$ 501,490	$ 127,318	$ 371,169	$ 152,059
Retained Functions	$ 81,423	$ 81,728	$ 79,018	$ 80,723	
Total Costs	**$ 670,278**	**$ 701,094**	**$ 427,369**	**$ 599,581**	**$ 364,784**
All costs in nominal dollars adjusted for inflation					

b) Economic Assessment

As was the case with full deployment of AMI, our preliminary economic assessment does not indicate that the savings opportunity normally associated with traditional outsourcing undertakings (such as IT, Finance, or HR) exist for outsourcing the partial AMI case. The total cost to SCE in both the full deployment and partial deployment outsourcing scenarios would be higher than the equivalent of SCE retaining the work in-house. For partial deployment the total cost of outsourcing (based on an averaging of service provider feedback) is estimated at $584 million whereas the cost of SCE performing the work is estimated at $365 million. To ensure an effective comparison both the outsourced scenario and the internal scenario were developed with all components included (*i.e.,* representing the end-to-end AMI solution including "back office" functions") and with a consistent inflation (escalation) factor applied to all scenarios.

In the partial case, outsourcing major components of the installation and operational phases of AMI would result in duplication of key customer service processes such as meter order processing for meter changes, billing exception processes resulting from new meter installations and meter failures, *etc.* SCE already has many of these processes and resources in place and would have to keep those resources in place not withstanding some level of outsourcing. Such duplication would not exist if SCE were to undertake a partial deployment of AMI on its own.

c) Summary of "Outsourcing" Findings

Although the scope and size of the partial-scope deployment scenario are much more manageable and represent a scope that has been outsourced by other organizations, there does not appear to be a compelling value proposition for outsourcing a partial deployment scenario unless it is intended as a pilot or proof of concept project. Initial analysis indicates no compelling financial justification to outsource partial deployment. However, justification may exist for other business objectives.

There were four integrated solution providers that participated in our analysis. Each provided varying degrees of completeness and each had somewhat different views of how the partial scope deployment AMI outsourced services would be provided. However, in the analysis, each has been normalized to allow a similar "apples-to-apples" comparison.

Based on the financial comparisons, the scope of services does not provide the traditional outsourcing value of reduced expense. This scope of services does not present the opportunity to consolidate the labor force, to leverage existing services, to buy products at significantly reduced rates or improve operational efficiency, all of which are typical ways outsourcing can result in lower costs. Moreover, outsourcing a partial-deployment scenario may introduce redundant services and systems into the solution.

(1) Installation and Start-up

The opportunity for outsourcing this scope of work is financially imbalanced because there will be a large infrastructure and labor overlap between the outsourcing provider and SCE. The financing of the meter assets and associated hardware components appears to have lower cost through SCE financing. All outsourcing providers proposed that SCE finance the meters, given that SCE's cost of capital appears lower than the service providers' rates.

As with the full deployment scenario, all of the integrated service providers proposed to partner with a meter manufacturer as part of their solution and they intended to complete the installations with contract labor. This use of contract labor may have union implications and would require further investigation.

Meter testing assumptions varied by provider. The testing rate would need to be adjusted to meet the required service. This has potential pricing impact, but cannot be estimated until the exact meter manufacturer is chosen and a commitment to a specific defect level is achieved.

The partial deployment scenario requires an inventory and distribution system that can handle the approximately 460,000 meters. All other IT modifications required for AMI would still be necessary. SCE would complete those modifications. SCE would also be required to perform the majority of the estimated customer application upgrades regardless of the decision on outsourcing. The exact cost of such interfaces has not been estimated, but there will be some cost to move data from the provider to SCE and visa versa that has not yet been accounted for.

The initial assessment of the partial outsourcing scenario indicates that, from a cost perspective, the start-up installation of a partial deployment would be less expensive for SCE to retain in-house than to outsource these functions. The outsourcing scenario also adds a governance cost to the total cost.

(2) Operations & Maintenance

On-going operations and maintenance for the partial-scope deployment was assumed to include O&M of the existing meters during the deployment phase (with inherent ramp down with the AMI rollout) and O&M of the new meters during the deployment phase (with inherent ramp up with the AMI rollout) and beyond (deployment was estimated to be in the first year). Responses from service providers included all functions up to and including delivering valid meter data to the billing function (with validation limited to reasonableness type of validation).

Determination on treatment of staff and the transition of staff to a service provider were dealt with only at a high level for this analysis. A number of issues related to union participation, severance, attrition, and training would also have an impact on the ongoing O&M function and cost.

The three integrated solution providers all provided solution descriptions that, at a high level, appear to meet the requirements. Additional analysis would be required to ensure work flows, hand-offs and responsibilities, and systems needs were fully defined.

Given that the cost of outsourcing exceeds the cost to SCE of performing these functions, we do not believe that outsourcing partial AMI deployment offers any benefits.

(3) Retained Responsibilities and Governance

Governance and relationship management costs were estimated at one percent of the service provider's estimated fee. These costs would be necessary to ensure that the performed functions and products meet the requirements and continue to comply with all regulations.

Retained responsibilities were identified for the meter functions (currently within our MSO, FSMRO, and TDBU (Rurals) organizations). These functions primarily would represent service delivery oversight, planning, design, customer relations, and other strategic functions.

Finally, responsibilities related to implementation and operation of AMI that were considered to be out of scope in the outsourcing analysis were identified as a utility-retained function and cost.

C. Scenario 16: Operational Plus Demand Response - TOU Default With Opt-Out

Scenario 16 adds a demand response element to the partial deployment Operational-Only scenario (Scenario 14). Not only do we include the costs associated with partial operational deployment of AMI as presented in Scenario 14, but we have added the cost associated with the goal of placing and keeping a minimum of 80 percent of the eligible AMI metered customers on time-of-use rates, 10 percent that "opt-out" to their current rate and 10 percent to a CPP-F rate, as in Scenario 4.[22] As was the case with Scenario 14, all costs and benefits included in the analysis of this scenario were estimated relative to the "business as usual" case. Table 4-16 summarizes the 2004 present-value dollar costs and benefits associated with Scenario 16, and compares these costs and benefits to Scenario 14.

[22] Our assumption is that 80% of the 70% (or approximately 56%) of the meters that are actually communicating would be able to participate on the default rate.

Table 4-16 Scenario 16 Cost and Benefits Compared to Scenario 14 (Millions in 2004 Present Value $)			
	Scenario 14	**Scenario 16**	**Difference**
Costs	$157.9	$242.2	$ 84.3
Benefits	$ 41.8	$64.4	$22.6
Pre-Tax Present Value	($116.2)	($177.8)	($61.6)
After Tax NPV	($80.2)	($117.9)	($37.7)
Rev. Req. NPV	($173.2)	($236.4)	$63.2

Scenario 16 derives all of the operational benefits previously discussed in Scenario 14 above plus approximately $18.5 million in demand response benefits resulting from energy and demand reduction savings attributable to time-of-use rates, and $4.1 million in additional benefits from making energy consumption information available to customers on the web.[23] These added benefits are offset, however, by added costs of more than $84.3 million, most of which is due to the massive customer communications campaign that would be required in order to meet the stringent twenty percent maximum opt-out limit imposed by this scenario.

1. Costs

The total estimated costs of Scenario 16 are detailed in Table 4-17

[23] The "Web" benefits derived in this scenario are the same as in the full deployment case because these are benefits derived from the upgraded web-based system that will be required to accommodate either the full or partial deployment case.

Table 4-17 Summary of Costs for Scenario 16 (000s in 2004 Pre-Tax Present Value Dollars)	
Cost Categories	**Total**
Metering System Infrastructure	$73,523
Communications Infrastructure	6,626
Information Technology Infrastructure	82,938
Customer Service Systems	52,371
Management and Miscellaneous Other	26,748
TOTAL:	$242,205

a) Meter System Installation and Maintenance

(1) Start-up and Design

Appendix A to the Ruling does not identify any cost categories for meter system start-up or design. As such, any start-up or design activities have been classified as installation costs below.

(2) Installation and Maintenance (MS-1 through MS-11)

For this scenario, the descriptions of activities and the associated costs for these cost categories are identical to those described in Scenario 14.

(3) Operation and Maintenance (MS-12 through MS-14)

For this scenario, the descriptions of activities and the associated costs for these cost categories are identical to those described in Scenario 14.

b) Communications Infrastructure

(1) Start-up and Design (C-1 through C-5)

In Scenario 16, descriptions of activities and the associated costs for cost codes C-2, C-3 and C-4 are the same as those described in Scenario 14. However, there are changes in the costs related to cost code C-1 and C-5. As discussed in Scenario 14, cost code C-1 captures the costs related to assessing the systems needed to ensure the security of the data transmitted within the network. Given the additional applications that we are enhancing, we expect that the labor associated with this assessment will increase from $0.11 million to $0.28 million.

As discussed in Scenario 14, cost code C-5 captures the costs related to determining the appropriate IT application solutions to retrieve and process meter data. As discussed below, we will need to enhance additional applications in order to facilitate demand response capabilities in our systems. Given the additional applications that we are enhancing, we expect that the contractor costs associated with IT application solution design will increase from $0.20 million to $0.37 million.

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 have estimated an increase from $0.63 million in Scenario 14 to $1.1 million in Scenario 16.

(2) Installation [C-6 through C-11]

In the installation area, there are two main differences between the Scenario 14 and Scenario 16 cost calculations. First, in Scenario 14, we did not have any incremental costs associated with cost code C-8. In Scenario 16, we will incur charges related to this cost category for 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 the equipment discussed in cost category C-10. Overall, the cost is estimated to be $0.96 million over the 2006 to 2021 timeframe.

Second, we also have differences in the costs associated with cost category C-10. In this scenario, we will continue to incur the $1.4 million in costs for the communications infrastructure hardware and equipment that were discussed in Scenario 14. In addition, we will need to procure communication equipment that will link SCE's network to the DS3 discussed above. This equipment will be installed in 2006 and will need to be refreshed every five years. The cost associated with this equipment is $81,000 over the 2006 to 2021 timeframe.

(3) Operation and Maintenance [C-12 through C-15]

In Scenario 16, the descriptions of activities and the associated costs for cost categories C-11, C-13, C-14 and C-15 are the same as those described in Scenario 14. The changes to this scenario are related to cost category

C-12. In Scenario 14, we did not have any charges associated with this cost category. However, in Scenario 16, 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.

c) Information Technology Infrastructure

The information technology and application cost category captures the costs associated with applications and computer services. In addition to the costs incurred for the full deployment operational case, we will incur additional charges when demand response rates are introduced.

(1) Applications

In the Scenario 14 discussion, we described the various applications that would need to be developed and/or enhanced. For Scenario 16, these same applications would be required. In addition, enhancements would be required to our Service Billing, Usage Calculation, Wholesale Settlement and SCE.com systems. The discussion that follows provides a brief description of 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. In Scenario 16, 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 that will be 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. In this scenario, 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 full deployment of AMI. As demand, energy, and power factor data are collected from meters, it 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 to the Wholesale Settlement system for financial settlement.

(c) Wholesale Settlement

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 ISO 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 demand response tariff schedules are introduced, the usage data received for wholesale settlement will be actual interval usage data, replacing the use of load profiles. As such, 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 nearly 0.44 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.

(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 fifteen minute data from the previous day. Customers will have access to available interval data for up to thirteen months and will be able to view charts and graphs for comparing applicable data. Customers will also be able to access analytical tools to manage energy usage and control 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. During non-critical event peak hours, we expect an increase in access over what we are experiencing today. During critical event peak hours, we expect a significant increase. The increase is based upon the assumption that we will have a significant volume of users accessing SCE.com during any given critical peak hour and that we will need to support an increase in concurrent user access as well.

(2) Start-up and Design (I-1)

For this scenario, the description of activities and the associated costs for this cost category are the same as described in Scenario 14.

(3) Installation (I-2 through I-7)

(a) 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 16, 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 billing. We are also enhancing SCE.com, our primary customer interface system. As compared to Scenario 14, in Scenario 16 we will need to procure additional hardware, storage, and operating software, including four additional processors and an additional 155 Gb of storage, to supplement the computing infrastructure designed for Scenario 14. Given the data processing requirements of the demand response scenario, we will also need to increase the mainframe resources by 123 MIPS and 254 GB in additional storage.

Another major cost driver in this cost code is related to customer bill printing. As new tariff schedules are introduced to facilitate customers' demand response, we are expecting that the number of pages in a typical customer's monthly bill will increase from four to six. In order to control 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 16, to facilitate demand response, we will be posting a customer's usage data on SCE.com, as discussed in further detail below. Upgrades will need to be made to our website servers in order to accommodate additional customers accessing SCE.com.

In Scenario 14, the cost associated with our computing systems upgrades was estimated to be $6.4 million. In Scenario 16, the costs are more extensive, estimated at $13.3 million.

(b) Data Center Facilities (I-3)

In Scenario 14, we did not have any incremental costs associated with cost category I-3. As discussed in cost category 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 $93,000 are being charged to this cost code in 2006.

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

As discussed in Scenario 14, a critical element of our IT application development efforts involves verifying that new applications or enhancements do not adversely affect existing systems that process meter changes and meter reads and calculate bills. To ensure no adverse effects, we will employ comprehensive testing techniques, such as regression, integration, unit and system testing. Since we are introducing more extensive application changes in Scenario 16, we will need to dedicate additional contractor resources to handle the testing activities. As such, we estimate the cost for these activities to increase from $25,000 to $222,000.

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

As described above, we will need to significantly enhance our Wholesale Settlement system. The costs associated with developing the system requirements and database schema for this system are captured in this cost category. In addition, with the introduction of additional applications in

Scenario 16, we will need to engage additional contractor resources to handle interface design and verification activities during the 2006 to 2021 timeframe. These activities are charged to various cost codes, including I-7 and I-8, depending upon the interface. The overall cost estimates for this cost code will increase from $11.5 million to $12.2 million.

Our Customer Service organization will partner with our IT organization in developing system and business requirements for the revisions that need to happen to 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 that customers find the website easy to use. We have estimated $0.17 million in labor costs associated with these activities over the 2006 to 2007 timeframe.

(e) Records (I-6)

Additional applications will be developed and enhanced in Scenario 16, including Usage Calculation, Service Billing and SCE.com. The costs associated with developing the system requirements and database schema is captured in this cost category. Given these additional applications, plus the extensive scope of the changes to them, we will need additional contractor resources to support these activities. We have estimated that the cost will increase from $0.53 million to $1.1 million in Scenario 16.

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

As detailed in the description for I-5, we will engage contractor resources to handle interface design and verification activities during 2006. In terms of the I-7 cost code, we estimate the cost for these activities will increase from $12,000 to $30,000.

(4) Operation and Maintenance (I-8 through I-16)

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

As detailed in the description for I-5, we will engage contractor resources to handle interface design and verification activities during 2006. In terms of the I-8 cost code, we estimate the cost for these activities will increase from $20,000 to $177,000.

(b) Process Bill Determinant Data (I-9)

In Scenario 16, 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 720 reads and 720 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 is expected to increase from $52,000 to $0.5 million.

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

As with Scenario 14, there are no incremental contract administration costs and the costs associated with infrastructure database management are included in I-16.

(d) Exception Processing (I-11)

As discussed in Scenario 14, our Billing Organization will continue to incur costs related to manual processing of accounts that fail billing system validations. In Scenario 16, 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, we expect to need additional personnel to handle this manual processing. Our cost estimates indicate an $11,000 increase in costs from Scenarios 14 to 16.

In terms of our IT systems, we will need to dedicate additional personnel to defining and developing the process by which exceptions are handled. We estimate the cost for these activities will increase from $62,000 to $98,000.

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

The descriptions of activities and the associated costs for these cost categories are the same as those described in Scenario 14.

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

As with Scenario 14, the incremental costs associated with ongoing data storage and handling were charged to cost code I-16.

(g) Ongoing IT Systems (I-14)

As discussed in Scenario 14, cost code I-14 captures the costs related to the ongoing O&M for applications support, security administration, database administration support, maintenance and enhancement activities associated with the portfolio of applications that have been developed or enhanced to support AMI. In Scenario 16, we are introducing 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 our portfolio. We have estimated that the labor and non-labor costs to perform these activities will increase from $9.9 million in Scenario 14 to $12.4 million in this scenario.

(h) Operating Costs (I-15)

The descriptions of activities and the associated costs for this cost code are the same as those described in Scenario 14.

(i) 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. Given that our computing systems are more extensive (as discussed in the description for cost code I-2) in this scenario than in Scenario 14, we will have more equipment subject to refresh in 2011 and 2016. As such, the costs for refreshing the computing systems and associated labor are estimated to increase from $8.2 million in Scenario 14 to $20.4 million in this scenario.

d) Customer Service Systems

(1) Start-up and Design

Appendix A to the Ruling does not identify any cost categories for customer service systems start-up or design. As such, any start-up or design activities have been classified as an installation cost below.

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

In the installation area, there is one main difference between the Scenario 14 and Scenario 16 cost estimates. In Scenario 16, there will be additional charges related to cost category CU-2 due to increased call volume resulting from rate change letters and "opt-out" inquiries to our Call Center. We expect to experience the same call volume level for mass communications and meter change letters in Scenario 16 as we did in Scenario 14. However, with the introduction of new rate schedules to facilitate customers' demand response, there will be additional customer communications that will ultimately lead to increased call volume. First, we will notify Zone 4 customers that their rate will be changed to a TOU 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 twenty-seven percent of customers call about opting out and seventy percent of those that call will actually choose to opt-out. Overall, we are expecting an increase of approximately 250,000 calls going from Scenario 14 to Scenario 16 and costs are expected to increase from approximately $100,000 to $1.5 million. This results in a total cost difference between the two scenarios of $1.4 million through 2021.

We also expect an increase in IT costs in cost code CU-3 going from $22,000 in Scenario 14, to $169,000 in Scenario 16.

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

(a) Additional Rate Analysis (CU-5)

As new rates are introduced in Scenario 16, 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. Customers who decide to opt out of the rate may want to request a rate analysis to determine a more appropriate rate. The total cost for MCD associated with these activities is expected to be $226,000 in cost code CU-5.

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

In Scenario 16, 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 16, these rate-related calls are expected to increase call volume by 40,000 calls per year at an added cost in cost code CU-8 of $230,000. Web-based rate communication costs are estimated at $353,000 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.

(c) 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 $17,000.

In Scenario 16, 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 $846,000.

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

The most significant cost difference in the operation and maintenance area between Scenarios 14 and 16 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 add a total of approximately $36.3 million in costs. Another $10.5 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.

e) Management and Miscellaneous Other

The Management and "Other" cost categories make up $14.3 million of the $84.3 million in incremental cost differences between Scenario 14 and Scenario 16. The majority of this increase is attributable to the need for $10.5 million in Marketing and Customer Communications expenditures needed to retain eighty percent of the AMI metered customers on TOU rates given that they will have the option of "opting-out" either to return to their otherwise applicable "tiered rate" or to move to an optional CPP rate. The $10.5 million in marketing costs assigned to this cost category is in addition to the $36.3 million described in the previous section in cost code CU-10. The remainder of the management and miscellaneous cost increases for Scenario 16 are described in the following sections.

(1) Start-up and Design (M-1 through M-2)

These two cost codes relate to meter installations and were addressed in the Operational-Only scenario. No additional costs would be incurred in this demand response scenario.

(2) Installation (M-3 through M-11)

Three of these Management cost codes (M-6, M-9 and M-11) have no costs associated with them in either Scenario 14 or 16. Cost code 8 was described in Scenario 14 above and has no incremental increases for Scenario 16.

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

We expect to incur approximately $846,000 in exception billing costs attributable to the increased availability of usage information to the customer.

(b) Employee Communications and Change Management (M-4)

We estimated $56,000 in additional cost related to all demand response scenarios over the duration of the analysis period for web related costs associated with employee communications.

(c) Employee Training for New Systems and Rate Structures, *etc.* (M-5)

Employee communication programs on the web will add $253,000 to this cost code for all demand response scenarios. This will supplement the Billing Organization and JST training described in Scenario 14 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.

(d) Project Management Costs and Overhead (M-7)

The Billing Organization, Call Center, IT and MCD combined will have approximately $2.4 million in management and overhead cost increases under this scenario. This is for indirect management and supervision activities related to the increases in personnel for the functions described previously in the Information Technology (I-1 through I-16) and customer Services (CU-1 through CU-10) cost codes.

(e) Call Center Training Costs (M-10)

The Call Center would incur $238,000 in additional cost for specialized training to be able to respond to the large anticipated call volume brought about by the "opt-out" provisions of the TOU default rate. This is in addition to the "Customer Services" cost impacts discussed previously under cost codes CU-2, CU-8, and CU-9 above.

(3) Operation and Maintenance Costs (M-12 through M-15)

Our capital financing costs are included within the Meter Acquisition costs described previously, and we did not use the M-12 cost code to include any additional or alternative financing costs. Nor have we identified any cost for increased load during mid-peak and off-peak periods (M-13).

(a) 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 $10.4 million of the $46.8 million to be spent on marketing and customer education programs that will be necessary to secure seventy percent of the AMI metered customers on TOU rates, and retain them on those rates for the duration of the analysis period

(b) Risk Contingencies (M-15)

Risk contingencies related to this scenario will be discussed in Section 3 below.

2. Benefits

Estimated benefits for Scenario 14 and Scenario 16 are compared by benefit category in Table 4-18 below.

Table 4- 18
Summary of Benefits for Scenario 14 vs. Scenario 16
(000s in 2004 Pre-Tax Present Value Dollars)

Benefit Categories	Scenario 14	Scenario 16	Difference
Systems Operations Benefits	$29,326	$29,326	$ -0-
Customer Service Benefits	1,144	4,028	2,883
Management and Other Benefits	11,286	12,492	1,206
Demand Response Benefits		18,530	18,530
TOTAL:	$41,756	$64,376	$22,620

Demand response benefits for this scenario are similar to Scenario 3 except this scenario applies only to Zone 4 customers. To determine demand response benefits, we used the Charles River Associates impact simulator model for SCE's Zone 4 adjusted for our cooling degree hours and air conditioning market penetration for that zone, as described in Volume 3, Scenario 3 and in Volume 2, Section III.

In addition to $18.5 million in demand response benefit, we expect to obtain $2.9 million in Customer Service benefits attributable to energy usage information being made available to customers on the web (CB-8). An additional $1.2 million benefit from website equipment offsets (MB-1) reflect the avoided cost of future investments resulting from overall website infrastructure improvements needed to meet AMI program needs.

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix B. For this scenario, the Value of Service loss is approximately $5.3 million ($2004 present value), reducing the total demand response benefit from $18.5 to $13.3 million.

3. Uncertainty and Risk Analysis

For Scenario 16, the total present value cost estimate is $242.2 million. We developed cost ranges as described in Scenario 14 and applied a Monte Carlo statistical analysis of costs that resulted in a range of $229.6 million to $262.2 million for this scenario. The statistical analysis indicates that our cost estimate has about a twenty-eight percent confidence. This means that the project has nearly a seventy-two percent chance of overrunning. Our preliminary cost estimates do not include contingency. However, based on our analysis, it would be appropriate to consider a contingency of approximately $10 million in our final application to reduce the risk of overrun. This contingency amount is the difference between our cost estimate and the value at the ninety percent confidence level.

Uncertainties in the area of demand response and associated benefits are similar to those of Scenario 3, described in Volume 3.

4. Net Present Value Analysis

Table 4-19 summarizes the overall pre-tax costs and benefits of Scenario 16. 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 sixteen-year analysis period.

Table 4-19
Summary of Cost/Benefit Analysis for Scenario 16
($ Millions)

Costs	Benefits	Pre-tax PV	After Tax NPV	Rev. Req. NPV
$242.2	$64.4	($177.8)	($117.9)	($236.4)

Scenario 16 results in a negative Revenue Requirement Present Value of $236.4 million and does not support the implementation of partial AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the Scenario 16 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.

D. Scenario 17: Operational Plus Demand Response - CPP-F/CPP-V/RTP Default With Opt-out

Similar to Scenario 16 above, Scenario 17 assumes partial deployment of AMI meters to Zone 4 customers. The only difference between Scenario 16 and Scenario 17 is that the default rate in this scenario is CPP-F for residential customers, and CPP-V and RTP for C & I customers (TOU was the default rate for all customers in

Scenario 16). Table 4-20 summarizes the costs and benefits of these two scenarios compared to the operational only Scenario 14.

Table 4-20
Comparison of Costs, Benefits, and NPV for Partial Deployment Scenarios 14, 16 and 17
(Millions of 2004 Pre-Tax Present Value Dollars)

	Cost	Benefit	Pre-Tax PV	After Tax NPV	Rev. Req. NPV
Scenario 14	$157.9	$41.8	($116.1)	($80.0)	($173.2)
Scenario 16	$242.2	$64.4	($177.8)	($117.9)	($236.4)
Scenario 17	$245.9	$90.0	($155.9)	($104.9)	($214.6)

The only cost difference between Scenario 16 and Scenario 17 is in the Marketing and Customer Communications programs, where we would expect to spend approximately $3.7 million more over the duration of the analysis period. This difference is entirely attributed to an increase of 350,000 subscribers (by 2021) to the SCE hosted “Envoy” CPP event notification service.[24] There are no other assumed operational cost differences between this scenario and those presented earlier in the Scenario 16 analysis.

Benefits are expected to be $25.6 million higher under this scenario. This increase is due to the higher number of customers participating on CPP rates and the significantly more favorable response to CPP rates verses TOU rates under Scenario 16.

1. Costs by Cost Code

Table 4-21 summarizes the Scenario 16 and Scenario 17 costs by cost category.

[24] The “Envoy” service was described previously in Volume 3, as part of the Scenario 4 discussion.

Table 4-21
Summary of Costs for Scenario 16 vs. Scenario 17
(000s in 2004 Pre-Tax Present Value Dollars)

Cost Categories	**Scenario 16**	**Scenario 17**	**Difference**
Metering System Infrastructure	$73,523	$73,523	$0
Communications Infrastructure	6,626	6,626	0
Information Technology Infrastructure	82,938	82,938	0
Customer Service Systems	52,370	56,056	3,686
Management and Miscellaneous Other	26,748	26,748	0
TOTAL:	$242,205	$245,891	$3,686

As pointed out above the only difference in cost for Scenario 17 over Scenario 16 is in cost code CU-10 where the entire $3.7 million increase is attributable to the CPP event notification process.

2. <u>Benefits</u>

Table 4-22 summarizes the Scenario 17 benefits by category and compares them to Scenario 14 and Scenario 16 benefits. Scenario 17 benefits are the same as those described previously for Scenario 16, except the demand response benefits are expected to increase by $25.6 million (going from $18.5 million in Scenario 16 to $44.2 million in Scenario 17). Scenario 17 is similar to Scenario 16 except the default rate for Scenario 17 is CPP, whereas the default rate for Scenario 16 was TOU. Scenario 17 is also similar to Scenario 4 except it applies only to Zone 4 customers.

Table 4-22 Summary of Benefits for Scenario 17 (000s in 2004 Pre-Tax Present Value Dollars)			
Benefit Categories	**Scenario 14**	**Scenario 16**	**Scenario 17**
Systems Operations Benefits	$29,326	$29,326	$29,326
Customer Service Benefits	1,144	4,028	4,028
Management and Other Benefits	11,286	12,492	12,492
Demand Response DR-1 Benefits	-0-	16,597	39,287
Demand Response DR-2 Benefits	-0-	1,933	4,877
TOTAL:	$41,756	$64,376	$90,009

This scenario assumes that eighty percent of eligible Zone 4 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 TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix C. For this scenario, the Value of Service loss is approximately $15.2 million ($2004 present value), reducing the total demand response benefit from $44.2 to $29.0 million.

3. Uncertainty and Risk Analysis

For Scenario 17, the total present value cost estimate is $245.9 million. The risk analysis for Scenario 17 is similar to that described for Scenario 16 Net Present Value Analysis.

Table 4-23 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 sixteen-year analysis period.

Table 4-23
Summary of Cost/Benefit Analysis for Scenario 17
($ Millions)

Costs	Benefits	Pre-tax PV	After Tax NPV	Rev. Req. NPV
$245.9	$90.0	($155.9)	($104.9)	($214.6)

Scenario 17 results in a negative Revenue Requirement Present Value of $214.6 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.

E. <u>Scenarios 18 and 19: Operational Plus Demand Response - Current Tariff with Opt-in to CPP Pure (Scenario 18) and Opt-in to CPP-F and CPP-V (Scenario 19)</u>

These two scenarios are prescribed in Attachment A of the Ruling as two of the five tariff structures to be analyzed in the partial deployment case.[25] Both our Scenario 18 and Scenario 19 assume the existing tariff structures will remain as the "default" tariff and customers will have the option of a CPP tariff in both scenarios. The only difference between Scenario 18 and Scenario 19 is that Scenario 18 offers the "CPP-Pure" rate option,[26] and Scenario 19 offers the "CPP-F" rate option to

25 Ruling, Attachment A, p.11

26 The "CPP-Pure" rate does not exist today. All current CPP rates fall back onto a time-of-use rate for non-critical peak periods. "CPP-Pure" would be a newly adopted rate schedule that would fall-back on the customers Otherwise Applicable Tariff (OAT) for non-critical peak periods.

residential customers and the "CPP-V" rate option to small C&I customers. From an operational standpoint, SCE assumes no difference in costs between Scenarios 18 and 19. The only difference being in the level of Demand Response benefits we would expect to receive between the two options.

For comparison purposes, we will describe the cost differences of these two scenarios relative to Scenario 17, which had CPP-F/V/and RTP as "default" tariffs, with a twenty percent "opt-out" assumption. Thus the following incremental differences in costs and benefits reflect the savings we expect would result from making CPP "optional" rather than the "default" tariff. This difference significantly reduces the level of customer participation, thus reducing not only the cost, but the demand response we expect would result.

Table 4-24 compares the costs and benefits for Scenarios 18 and 19 to the costs and benefits we expect for Scenario 14 and Scenario 17.

Table 4-24
Comparison of Costs, Benefits, and NPV for Partial Deployment Scenarios 14, 17, 18 and 19
(Millions of 2004 Pre-Tax Present Value Dollars)

	Cost	Benefit	Pre-Tax PV	After Tax NPV	Rev. Req. NPV
Scenario 14	$157.9	$41.8	($116.2)	($80.2)	($173.2)
Scenario 17	$245.9	$90.0	($155.9)	($104.9)	($214.6)
Scenario 18	$239.4	$68.8	($170.6)	($170.6)	($229.2)
Scenario 19	$239.4	$70.8	($168.6)	($168.6)	($227.2)

1. <u>Costs by Cost Code</u>

This section will describe the differences between the incremental costs by cost code for Scenario 17 and the incremental costs for Scenarios 18 and 19 (the costs for 18 and 19 being identical). These cost differences are summarized below in Table 4-25.

Table 4-25
Summary of Costs for Scenario 18
(000s in 2004 Pre-Tax Present Value Dollars)

Cost Categories	**Scenario 17**	**Scenario 18**	**Scenario 19**	**Difference (17 v. 18 & 19)**
Metering System Infrastructure	$73,523	$73,523	$73,523	$ -0-
Communications Infrastructure	6,626	7,213	7,213	587
Information Technology Infrastructure	82,938	82,817	82,817	(121)
Customer Service Systems	56,056	51,726	51,726	(4,330)
Management and Miscellaneous Other	26,748	24,144	24,144	(2,604)
TOTAL:	$245,891	$239,422	$239,422	($6,469)

a) Meter System Installation and Maintenance

For Scenarios 18 and 19, the costs are identical to those described in Scenario 17.

b) Communications Infrastructure

For Scenarios 18 and 19, the cost difference relative to Scenario 17 is contained within cost category C-5 for implementation of the CPP Pure rate, which is a new rate for SCE. To implement the new CPP Pure rate, we estimate the need for an additional Project Manager and Business Analyst to work with IT and affected SCE organizations, to develop the processes, design and develop system requirements, follow through from system test to implementation, communicate new rate information, and support ongoing system and implementation issues. We have estimated an increase in labor costs of $0.59 million for Scenarios 18 and 19 for this additional activity.

c) Information Technology Infrastructure

In Scenarios 18 and 19, the cost differences relative to Scenario 17 are contained within 2 cost categories, I-9 and I-11. With the introduction of demand response rates, our Billing Organization will see an increase in the amount of usage data that is collected and processed. As discussed previously, we expect that there will be additional usage validation failures and billing validation failures in demand response scenarios than what we would see in operational only scenarios. Additional customer service representatives are needed to manually process the accounts that the system is unable to process. The number of additional personnel that we need for this activity will vary between Scenarios 17, 18 and 19. Our personnel estimates are driven by the number of customers on a rate requiring interval data. Since we anticipate a smaller number of customers will have rates requiring interval data in Scenarios 5 and 6, we anticipate that we will need less customer service representatives to handle this manual processing of accounts. For cost code I-9, we anticipate decreasing our cost estimate from $4.82 million in Scenario 17 to $4.81 million in Scenarios 18 and 19. For cost code I-11, our cost estimate decreases by $11,000 from Scenario 17 to Scenarios 18 and 19.

d) Customer Service Systems

Customer Service Systems costs are lower for Scenarios 18 and 19 in two specific areas:

- Marketing and customer costs in cost code CU-10 will be $3.2 million lower for these scenarios than for Scenario 17. This is due to the expected smaller number of customer participants and the reduced call volumes for proactive notification of CPP events to those customers who subscribe to the "Envoy" service hosted by SCE.[27]

- Call Center costs will be $0.9 million lower, due again to the lower number of active participants and lower anticipated call volume because there will be no "default" rate change notices and no "opt-out" provision under these scenarios. These costs are shown in cost code CU-2. Cost code CU-8 and CU-9 estimates for the Call Center are also lower for these two scenarios by $0.2 million and $15,000, respectively. This is due to fewer calls expected during CPP events, and resulting bill impacts.

e) <u>Management and Miscellaneous Other Costs</u>

The Management and Other cost categories are $2.6 million lower for these two scenarios due primarily to $3.4 million less required for "customer acquisition and marketing" costs in cost code M-14, as a result of the less stringent requirements of the "Opt-in" assumption. Project Management costs (cost code M-7) are also expected to be $110,000 lower in the Call Center and $1.0 million higher in the Billing Organization over the duration of the analysis period. Call Center training costs (cost code M-10) will also be lower by $127,000, again due to the lower anticipated call volume and reduced training expenses (*i.e.*, fewer new employees).

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[27] For a more detailed description of the Envoy service and the associated costs see Scenario 4 costs in Volume 3, Section III.

2. Benefits

Scenario 18 in the partial deployment case is similar to Scenario 5 in the full deployment case, except that twenty-five percent of AMI metered residential and C&I customers are assumed to Opt-in to the CPP-Pure rate and remain there until 2021. We used the MMI model to determine the customer enrollment percentage in the first year and we used that same percentage for every year in the analysis. For the purposes of the analysis, we used the demand response behavior in the SPP for CPP-F as a proxy for CPP-Pure since the latter was not tested in the experiment.

Under Scenario 19, residential and small commercial/industrial customers below 200 kW could opt-in to either a CPP-F or CPP-V rate. Scenario 19 in the partial deployment case is similar to Scenario 6 in the full deployment case, except that eighteen percent of eligible customers would opt-in to CPP-F and six percent would opt-in to CPP-V. We used the MMI model to determine customer enrollment in CPP-F and CPP-V rates. We also assumed the same customer response to CPP-F rates in the SPP for this analysis for both CPP-F and CPP-V. For C&I customers, the SPP did not find statistically significant price elasticities. Therefore, we used the CPP-F price elasticity results from the SPP times a factor of twenty-five percent which is consistent with the literature for C&I price elasticity relative to residential price elasticity. The demand response benefits for Scenarios 18 and 19 as compared to Scenario 17 are shown in Table 4-26 below.

Table 4-26 Summary of Benefits for Scenario 17, 18 and 19 (Millions in 2004 Pre-Tax Present Value Dollars)			
Benefit Categories	**Scenario 17**	**Scenario 18**	**Scenario 19**
Systems Operations Benefits*	$29,326	$29,326	$29,326
Customer Service Benefits*	4,028	4,028	4,028
Management and Other Benefits*	12,492	12,492	12,492
Demand Response DR-1 Benefits	39,287	20,328	22,172
Demand Response DR-2 Benefits	4,877	2,655	2,788
TOTAL:	$90,009	$68,828	$70,806

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix B. For Scenario 18, the Value of Service loss is approximately $10 million ($2004 present value), reducing the total demand response benefit from $23 to $13 million. For Scenario 19, the Value of Service loss is approximately $10 million (2004 present value), reducing the total demand response benefit from $25 to $15 million.

Table 4-27 Tiered Default with Opt-in to CPP-Pure (Scenario 18) Current Tariff with Opt-in to CPP-F or CPP-V (Scenario 19)		
	No. of Meters (Customers) Year 2021	**Percent of Eligible Meters**
Meters Eligible for TDRs	382,772	
Customers Enrolled on CPP-Pure (Scenario 18)	99,065	25
Customers Enrolled on Tiered Rate (Scenario 18)	283,706	75
Customers on CPP-F (Scenario 19)	75,082	18
Customers on CPP-V (Scenario 19)	24,653	6
Customers Enrolled on Tiered Rate (Scenario 19)	283,037	76

3. Uncertainty and Risk Analysis

For Scenarios 18 and 19, the total present value cost estimate is $239.4 million. We developed cost ranges as described in Scenario 14 and applied a Monte Carlo statistical analysis of costs that resulted in a range of $225.6 million to $260.9 million for this scenario. The statistical analysis indicates that our cost estimate has about a thirty-one percent confidence. This means that the project has nearly a sixty-nine percent chance of overrunning. Our preliminary cost estimates do not include contingency. However, based on our analysis, it would be appropriate to include a contingency of approximately $9.5 million in our final application to reduce the risk of overrun. This contingency amount is the difference between our cost estimate and the value at the ninety percent confidence level.

Uncertainty and risks with respect to demand response benefits for Scenarios 18 and 19 are similar to Scenarios 5 and 6, respectively. (*See* Volume 3.)

4. Net Present Value Analysis

Table 4-28 summarizes the overall pre-tax costs and benefits of Scenarios 18 and 19. Also shown is the after-tax NPV for these scenarios on a cash flow basis, and the present value of the revenue requirement over the sixteen-year analysis period.

Table 4-28
Summary of Cost/Benefit Analysis for Scenarios 18 & 19
($ Millions)

Scenario	Costs	Benefits	Pre-tax Present Value	After-Tax NPV	Rev. Req. Present Value
Scenario 18	$239.4	$68.8	($170.6)	($113.6)	($229.2)
Scenario 19	$239.4	$70.8	($168.6)	($112.5)	($227.2)

Scenarios 18 and 19 both result in a negative Revenue Requirement Present Value of $229.2 million and $227.2 million, respectively. Neither of these two scenarios supports the implementation of a partial AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the Scenario 18 and 19 analyses, 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.

F. Scenarios 20 and 21: Operational Plus Demand Plus Reliability - Current Tariff With Opt-In To CPP Pure (Scenario 20) and Opt-in to CPP-F and CPP-V (Scenario 21)

Scenario 20 is similar to Scenario 18 and Scenario 21 is similar to Scenario 19 except that we include the full benefit of the ALC program in both scenarios as the reliability component. The ruling directs us to evaluate additional reliability benefits if the AMI is coupled with active use of ALC technology. The ALC program was included as part of our Long-Term Resource Procurement Plan in our 2005 Demand Response Proposals which were filed on October 15, 2004.[28] Both our Scenario 20 and Scenario 21 analyses assume the existing tariff structures will remain as the "default" tariff and customers will have the option of a CPP tariff in both scenarios. Scenarios 20 and 21 differ from the Demand Response + Reliability Scenario 8 in that there is no adjustment for reducing the ALC program due to certain customers opting-in to a CPP rate. This is because the amount of customer overlap between a CPP rate and ALC just for Zone 4 is relatively small compared to Scenario 8. The only difference between Scenario 20 and Scenario 21 is that Scenario 20 offers the "CPP-Pure" rate option,[29] and Scenario 21 offers the "CPP-F" rate option to residential customers and the "CPP-V" rate option to C&I customers. From an operational standpoint, SCE assumes no difference in costs between Scenarios 20 and 21. The only difference is in the level of Demand Response benefits we would expect to receive between the two options.

1. Costs

For comparison purposes, we will describe the cost differences of these two scenarios relative to Scenarios 18 and 19. Table 4-29 summarizes the costs and cost differences by category.

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[28] SCE's Demand Response Program Proposals for 2005-2008, in R.02-06-001

[29] The "CPP-Pure" rate does not exist today. All current CPP rates fall back onto a time-of-use rate for non-critical peak periods. "CPP-Pure" would be a newly adopted rate schedule that would fall-back on the customers Otherwise Applicable Tariff (OAT) for non-critical peak periods.

Table 4-29 Summary of Costs for Scenario 18/19 vs. Scenario 20/21 (000s in 2004 Pre-Tax Present Value Dollars)			
Cost Categories	**Scenario 18/19**	**Scenario 20/21**	**Difference**
Metering System Infrastructure	$73,523	$383,275	$309,752
Communications Infrastructure	7,213	7,213	-0-
Information Technology Infrastructure	82,817	82,817	-0-
Customer Service Systems	51,725	51,725	-0-
Management and Miscellaneous Other	24,144	24,144	-0-
TOTAL:	$239,422	$549,174	$309,752

The only cost code that changes when evaluating Scenarios 20 and 21 in relation to Scenarios 18 and 19 is cost code MS-12. In Scenarios 20 and 21, this cost code captures the costs associated with the ALC program. The activities and associated costs are discussed in detail in the following section.

a) Meter System Installation and Maintenance

The only cost difference between Scenarios 20 and 21 and Scenario 18 and 19 relates to the ALC program. The ALC program modifies the existing air conditioning cycling program to include an economic dispatch option. In addition, new digital and programmable thermostats are combined with the existing load control switches. Customers will be provided an incentive payment in exchange for allowing SCE to dispatch the program when most economically effective as well as when emergency situations arise.

In Scenarios 20 and 21, the cost estimates of $309.8 million, which are captured in cost code MS-12, are based upon the assumption that we will capture the full market potential of 500,000 customers that is projected for our new

ALC program by 2011.[30] We are also assuming that the ALC program is approved in early 2005 and the equipment necessary to participate in the program is installed at approximately 142,000 of participating customers' homes or businesses within 2005.

The cost estimate of $309.8 million is comprised of the costs associated with equipment, installation, customer incentive payments and program administration that are incurred over the 2006 to 2021 timeframe. Beginning in 2006, we will incur equipment and installation costs associated with enrolling approximately 358,000 customers on the new ALC program. In terms of equipment costs, our estimates are based upon thirty percent of participating customers choosing to have a direct load control switch installed on their air conditioning unit. This installation will be handled by a contractor resource. The equipment and installation costs are estimated at $161 per customer.

For the remaining seventy percent of customers, we are assuming that a load control transceiver will be installed on the air conditioning unit. This transceiver will have the ability to control the customer's air conditioning unit by communicating with the customer's thermostat. The equipment costs associated with the thermostat and load control transceiver are estimated to be $95 per customer. In addition, we will incur installation costs. The contractor resource costs associated with installing a thermostat in a customer's home or business is estimated to be $90. In terms of the load control transceiver installation costs, we are assuming that fifty percent of the meters will have the module embedded by the vendor at the time of manufacturing. In these cases, there will be no additional installation costs, since we will be utilizing the installers discussed in cost code MS-5 in Scenario 14 to handle the installation of the AMI

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[30] This estimate assumes that the existing customers that are participating on our existing air conditioning cycling program will be migrated to the new program.

meters. However, in fifty percent of the cases, we are assuming that the AMI meter will already have been installed and will need to be replaced with one that contains the load control transceiver. In those cases, we have captured the costs associated with having an installer visit the customer's site to reinstall the meter.

The majority of the $309.8 million cost estimate can be attributed to customer incentive payments. Customers who sign up on the ALC program will have the option of selecting from three different options during an event: 1) shedding 100 percent of their load, or 2) shedding fifty percent of their load, or increasing their temperature setting by 4º F. Incentive payments vary by the option selected and are paid only during the summer season, defined as the first Sunday in June to first Sunday in October. The average incentive payment, assuming four ton per air conditioning unit and thirty days per month, is $86.40 for customers selecting the 100 percent load shed option. Customers opting for the fifty percent load shed option will receive on average $48.00. This fifty percent load shed incentive level is assumed to be the same as the incentive level associated with the 4º F set-back option. We also plan to incur minimal costs on an annual basis associated with program administration and customer communications.

b) Communications Infrastructure

The communications infrastructure costs for Scenarios 20 and 21 are identical to those contained in Scenarios 18 and 19.

c) Information Technology Infrastructure

The information technology infrastructure costs for Scenarios 20 and 21 are identical to those contained in Scenarios 18 and 19.

d) Customer Service Systems

The customer service systems costs are the same in Scenarios 20 and 21 as they are in Scenarios 18 and 19.

e) Management and Miscellaneous Other

The management and miscellaneous other costs for Scenarios 20 and 21 are identical to those contained in Scenarios 18 and 19.

2. Benefits

Table 4-30 shows the expected benefits by benefit category for Scenarios 18, 19, 20 and 21.

Table 4-30
Summary of Benefits for Scenario 20
(000s in 2004 Pre-Tax Present Value Dollars)

Benefit Categories	Scenario 18	Scenario 19	Scenario 20	Scenario 21
Systems Operations	$29,326	$29,326	$29,326	$29,326
Customer Service	4,028	4,028	4,028	4,028
Management and Other	12,492	12,492	12,492	12,492
Demand Response	22,983	24,961	472,473	474,470
TOTAL:	$68,828	$70,806	$518,318	$520,316

a) System Operations Benefits (SB-1 through SB-13)

The system operations benefits in Scenarios 20 and 21 are identical to the benefits in Scenarios 18 and 19.

b) Customer Service Benefits (CB-1 through CB-13)

Customer service benefits in Scenarios 20 and 21 are identical to the benefits in Scenarios 18 and 19.

c) Management and Other Benefits (MB-1 through MB-10)

Management and other benefits in Scenarios 20 and 21 are identical to the benefits in Scenarios 18 and 19.

d) Demand Response Benefits (DR-1, DR-2)

Scenario 20 assumes that residential and C&I customers will opt in to the CPP-Pure rate and that a group of other residential customers, either on a TOU rate or their current rate, would enroll in ALC, providing a reliability feature. We used the MMI model to determine customer enrollment percentage in the first year and used that same percentage for every year in the analysis. For the purposes of the revised preliminary analysis, we used the demand response behavior in the SPP for CPP-F as a proxy for CPP-Pure since the latter was not tested in the experiment. The demand response benefits are shown in Table 4-31 below.

Table 4-31
Current Default with Opt-in to CPP-Pure+Reliability (Scenario 20)

	No. of Meters (Customers) Year 2021	Percent of Eligible Meters	Present Value ($ millions)
Meters Eligible for TDRs	382,772		
Customers Enrolled on CPP-Pure	99,065	25	
Customers Enrolled on Current	283,706	75	
Customers Enrolled in AC cycling	500,000	0	
Total DR-1 Benefits			$418.5
Total DR-2 Benefits			$54.0
Total			$472.5

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix B.

For this scenario, we have not calculated the Value of Service loss for the ALC component of benefits.[31] The demand response benefits from customers enrolled on CPP-Pure would decrease by $10 million from $472 million to $462 million.

Scenario 21 assumes that residential customers will opt in to CPP-F rates and C&I customers will opt in to CPP-V rates. We assume the full ALC program would provide a reliability feature. We used the MMI model to determine customer enrollment percentage in the first year and used that same percentage for every year in the analysis. The demand response benefits are shown in Table 4-32 below.

Table 4-32
Current Tariff with Opt-in to CPP F/V (Scenario 21)

	No. of Meters (Customers) Year 2021	Percent of Eligible Meters	Present Value ($ millions)
Meters Eligible for TDRs	382,772		
Customers Enrolled on CPP-F	76,199	18	
Customers Enrolled on CPP-V	23,345	6	
Customers Enrolled on Current	283,227		
Customers Enrolled in AC cycling	500,000	0	
Total DR-1 Benefits			$421
Total DR-2 Benefits			$54
Total Demand Response Benefits			$475

We have not adjusted the above demand response benefits for Value of Service loss to customers due to participation in TDRs. Our methodology and analysis of Value of Service loss by scenario is presented in Volume 2, Appendix B. For this scenario, we have not calculated the Value of Service loss for the ALC

[31] Value of Service Loss for the ALC portion of demand response is not included, but may also apply.

component of benefits.[32] The demand response benefits from customers enrolled on CPP-F/V would decrease by $11 million from $475 million to $464 million.

3. Uncertainty and Risk Analysis

Scenarios 20 and 21 costs and operational benefit risks and analyses are the same as described in Scenarios 18 and 19.

Uncertainty with respect to demand response benefits for Scenario 20 is the same as for Scenario 8 (*see* Volume 3). Uncertainty with respect to demand response benefits for Scenario 21 is similar to Scenario 6 (*see* Volume 3).

4. Net Present Value Analysis

Table 4-33 summarizes the overall pre-tax costs and benefits of Scenarios 20 and 21. Also shown is the after-tax NPV for these scenarios on a cash flow basis, and the present value of the revenue requirement over the sixteen-year analysis period.

Table 4-33
Summary of Cost/Benefit Analysis for Scenarios 20 & 21
($ Millions)

Scenario	Costs	Benefits	Pre-tax Present Value	After-Tax NPV	Rev. Req. Present Value
Scenario 20	$549.2	$518.3	($30.9)	($63.4)	($117.8)
Scenario 21	$549.2	$520.3	($28.9)	($62.3)	($115.8)

Scenarios 20 and 21 both result in a negative Revenue Requirement Present Value of $117.8 million and $115.8 million, respectively, and neither of these two scenarios supports the implementation of a partial AMI deployment. The Revenue Requirement analysis incorporates the costs and benefits derived in the

[32] Value of Service Loss for the ALC portion of demand response is not included, but may also apply.

scenario 20 and 21 analyses, 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.

V.

REVENUE REQUIREMENT AND RATE 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 partial deployment scenarios.[33] The revised preliminary revenue requirement presented in this section summarizes the operating expenses and investment-related costs identified in Section III and IV above. A cost recovery and ratemaking proposal to recover the AMI-related revenue requirements will be provided in our December, 2005 AMI filing.

Table 4-34 provides the estimated net AMI-related revenue requirement and average customer monthly dollar impacts for each of the partial deployment scenarios.

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. In order to calculate the average customer impacts, SCE utilized the total system retail sales forecast as presented in SCE's 2004 Long-Term Procurement Plan testimony filed on July 9, 2004 in R.04-04-003.

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[33] Due to the 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 2020. These unrecovered costs [of approximately $58 million in unrecovered net plant for the full-deployment scenarios (Scenarios 1-8), and $3.4 million for the Zone 4 partial-deployment scenarios (Scenarios 14-23)] 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' fifteen-year life and their later in-service dates

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, applicable taxes and return on rate base calculated at the Commission-authorized rate of return.[34] The return on rate base amounts included in the Revenue Requirements presented in Table 4-34 uses our currently authorized rate of return on rate base of 9.07 percent.

As discussed in Sections II and III of 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, this revenue requirement analysis amortizes 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.

B. Expected Revenue Requirement Reductions

In order to estimate the net AMI-related revenue requirement impacts, the expected cost savings derived from the AMI benefit have been deducted from the AMI cost-related revenue requirement increase. The cost savings or revenue

[34] SCE has assumed a 15-year recovery period associated with the new meters.

requirement reductions include: (1) Customer Service-related O&M reductions; (2) existing meter revenue requirement reductions; and (3) procurement cost reductions due to demand response.

Table 4-34
AMI Revenue Requirement and Average Monthly Customer Impacts – (Partial AMI Deployment) - (000s of Dollars)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Scenario 12 - Partial-DR-RTEM-RTP																
AMI Meter Installation Revenue Requirements	5,981	5,279	3,831	3,830	3,823	3,879	134	136	136	132	134	132	134	130	131	124
Stranded Cost Revenue Requirement - 5 year	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meter Revenue Requirement in Rates	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Expected Procurement Reductions	(37,131)	(37,131)	(37,131)	(37,131)	(37,131)	(37,131)	(37,131)	(37,131)	(37,131)	(37,131)	(37,131)	(37,131)	(37,131)	(37,131)	(37,131)	(37,131)
Total Net AMI-related Rev Req Impact	**(31,150)**	**(31,852)**	**(33,300)**	**(33,301)**	**(33,308)**	**(33,252)**	**(36,997)**	**(36,996)**	**(36,995)**	**(36,999)**	**(36,997)**	**(36,999)**	**(36,998)**	**(37,001)**	**(37,001)**	**(37,007)**
Avg Monthly Customer Dollar Impact	**(0.54)**	**(0.54)**	**(0.56)**	**(0.55)**	**(0.55)**	**(0.54)**	**(0.59)**	**(0.58)**	**(0.58)**	**(0.57)**	**(0.56)**	**(0.56)**	**(0.55)**	**(0.54)**	**(0.54)**	**(0.53)**
Scenario 13 - Partial-DRR-RTEM-RTP																
AMI Meter Installation Revenue Requirements	58,300	57,599	56,152	56,151	56,144	56,199	52,454	52,456	52,455	52,451	52,454	52,453	52,454	52,450	52,450	52,443
Stranded Cost Revenue Requirement - 5 year	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Meter Revenue Requirement in Rates	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Expected Procurement Reductions	(73,318)	(73,318)	(73,318)	(73,318)	(73,318)	(73,318)	(73,318)	(73,318)	(73,318)	(73,318)	(73,318)	(73,318)	(73,318)	(73,318)	(73,318)	(73,318)
Total Net AMI-related Rev Req Impact	**(15,018)**	**(15,719)**	**(17,166)**	**(17,167)**	**(17,174)**	**(17,119)**	**(20,864)**	**(20,862)**	**(20,863)**	**(20,867)**	**(20,865)**	**(20,866)**	**(20,864)**	**(20,868)**	**(20,868)**	**(20,875)**
Avg Monthly Customer Dollar Impact	**(0.26)**	**(0.27)**	**(0.29)**	**(0.29)**	**(0.28)**	**(0.28)**	**(0.33)**	**(0.33)**	**(0.33)**	**(0.32)**	**(0.32)**	**(0.31)**	**(0.31)**	**(0.31)**	**(0.30)**	**(0.30)**
Scenario 14 - PartialOperational-Zone4-Utility																
AMI Meter Installation Revenue Requirements	45,120	26,716	24,442	23,446	22,879	20,916	18,571	17,905	17,601	17,405	18,053	18,412	17,922	17,432	16,861	12,405
Stranded Cost Revenue Requirement - 5 year	15,627	14,629	12,804	6,640	14,107	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	(991)	(2,654)	(4,387)	(4,531)	(4,702)	(4,856)	(5,040)	(5,209)	(5,409)	(5,593)	(5,806)	(6,004)	(6,234)	(6,406)	(6,580)	(6,765)
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	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Net AMI-related Rev Req Impact	**59,481**	**38,342**	**32,400**	**25,095**	**31,825**	**15,600**	**13,071**	**12,235**	**11,733**	**11,352**	**11,788**	**11,948**	**11,228**	**10,566**	**9,821**	**5,180**
Avg Monthly Customer Dollar Impact	**1.03**	**0.66**	**0.55**	**0.42**	**0.52**	**0.25**	**0.21**	**0.19**	**0.18**	**0.18**	**0.18**	**0.18**	**0.17**	**0.16**	**0.14**	**0.07**
Scenario 16 - Partial-DR-Zone4-TOU-Opt-20																
AMI Meter Installation Revenue Requirements	65,224	45,344	40,847	38,435	36,798	35,350	34,843	22,877	22,387	21,904	23,871	24,360	23,676	22,994	22,336	17,099
Stranded Cost Revenue Requirement - 5 year	15,627	14,629	12,804	6,640	14,107	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	(1,033)	(3,209)	(4,939)	(5,100)	(5,404)	(5,491)	(5,696)	(5,888)	(6,111)	(6,319)	(6,556)	(6,780)	(7,036)	(7,233)	(7,430)	(7,642)
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	(2,859)	(2,896)	(2,933)	(2,971)	(3,009)	(3,048)	(3,087)	(3,127)	(3,167)	(3,208)	(3,249)	(3,291)	(3,334)	(3,377)	(3,420)
Total Net AMI-related Rev Req Impact	**79,543**	**53,557**	**45,357**	**36,582**	**42,070**	**26,390**	**25,639**	**13,443**	**12,690**	**11,958**	**13,647**	**13,871**	**12,889**	**11,968**	**11,070**	**5,577**
Avg Monthly Customer Dollar Impact	**1.38**	**0.92**	**0.76**	**0.61**	**0.69**	**0.43**	**0.41**	**0.21**	**0.20**	**0.18**	**0.21**	**0.21**	**0.19**	**0.18**	**0.16**	**0.08**
Scenario 17 - Partial-DR-Zone4-CPP-Opt-20																
AMI Meter Installation Revenue Requirements	65,224	46,258	41,344	38,948	37,326	35,895	35,407	23,466	22,996	22,540	24,528	25,044	24,350	23,698	23,064	17,857
Stranded Cost Revenue Requirement - 5 year	15,627	14,629	12,804	6,640	14,107	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	(1,033)	(3,209)	(4,939)	(5,100)	(5,404)	(5,491)	(5,696)	(5,888)	(6,111)	(6,319)	(6,556)	(6,780)	(7,036)	(7,233)	(7,430)	(7,642)
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	(6,818)	(6,905)	(6,993)	(7,082)	(7,173)	(7,264)	(7,357)	(7,451)	(7,547)	(7,643)	(7,741)	(7,841)	(7,941)	(8,043)	(8,146)
Total Net AMI-related Rev Req Impact	**79,543**	**50,512**	**41,845**	**33,036**	**38,487**	**22,772**	**21,987**	**9,762**	**8,974**	**8,214**	**9,868**	**10,063**	**9,014**	**8,065**	**7,132**	**1,609**
Avg Monthly Customer Dollar Impact	**1.38**	**0.86**	**0.71**	**0.55**	**0.63**	**0.37**	**0.35**	**0.15**	**0.14**	**0.13**	**0.15**	**0.15**	**0.13**	**0.12**	**0.10**	**0.02**
Scenario 18 - Partial-DR-Zone4-CPP-Pure																
AMI Meter Installation Revenue Requirements	65,826	44,322	40,233	37,393	35,629	34,130	33,521	23,030	22,540	22,063	24,032	24,526	23,847	23,170	22,517	17,282
Stranded Cost Revenue Requirement - 5 year	15,627	14,629	12,804	6,640	14,107	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	(1,033)	(3,209)	(4,939)	(5,100)	(5,404)	(5,491)	(5,696)	(5,888)	(6,111)	(6,319)	(6,556)	(6,780)	(7,036)	(7,233)	(7,430)	(7,642)
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	(3,546)	(3,591)	(3,638)	(3,684)	(3,732)	(3,780)	(3,829)	(3,878)	(3,928)	(3,979)	(4,031)	(4,083)	(4,136)	(4,189)	(4,244)
Total Net AMI-related Rev Req Impact	**80,144**	**51,848**	**44,047**	**34,836**	**40,188**	**24,447**	**23,585**	**12,853**	**12,091**	**11,355**	**13,037**	**13,255**	**12,268**	**11,342**	**10,438**	**4,936**
Avg Monthly Customer Dollar Impact	**1.39**	**0.89**	**0.74**	**0.58**	**0.66**	**0.40**	**0.38**	**0.20**	**0.19**	**0.18**	**0.20**	**0.20**	**0.18**	**0.17**	**0.15**	**0.07**
Scenario 19 - Partial-DR-Zone4-CPP-FV																
AMI Meter Installation Revenue Requirements	65,826	44,322	40,233	37,393	35,629	34,130	33,521	23,030	22,540	22,063	24,032	24,526	23,847	23,170	22,517	17,282
Stranded Cost Revenue Requirement - 5 year	15,627	14,629	12,804	6,640	14,107	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	(1,033)	(3,209)	(4,939)	(5,100)	(5,404)	(5,491)	(5,696)	(5,888)	(6,111)	(6,319)	(6,556)	(6,780)	(7,036)	(7,233)	(7,430)	(7,642)
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	(3,846)	(3,897)	(3,948)	(3,999)	(4,052)	(4,105)	(4,159)	(4,213)	(4,269)	(4,325)	(4,382)	(4,439)	(4,498)	(4,557)	(4,617)
Total Net AMI-related Rev Req Impact	**80,144**	**51,548**	**43,742**	**34,526**	**39,873**	**24,127**	**23,260**	**12,523**	**11,756**	**11,015**	**12,691**	**12,904**	**11,911**	**10,980**	**10,070**	**4,563**
Avg Monthly Customer Dollar Impact	**1.39**	**0.88**	**0.74**	**0.57**	**0.65**	**0.39**	**0.37**	**0.20**	**0.18**	**0.17**	**0.19**	**0.19**	**0.18**	**0.16**	**0.15**	**0.07**
Scenario 20 - Partial-DRR-Zone4-CPP-Pure																
AMI Meter Installation Revenue Requirements	98,999	89,414	89,339	90,508	97,687	93,482	82,193	71,649	71,236	77,770	72,944	73,576	73,048	72,545	72,072	67,043
Stranded Cost Revenue Requirement - 5 year	15,627	14,629	12,804	6,640	14,107	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	(1,033)	(3,209)	(4,939)	(5,100)	(5,404)	(5,491)	(5,696)	(5,888)	(6,111)	(6,319)	(6,556)	(6,780)	(7,036)	(7,233)	(7,430)	(7,642)
Meter Revenue Requirement in Rates	(275)	(349)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)
Expected Procurement Reductions	(28,041)	(42,468)	(54,439)	(65,121)	(74,612)	(83,006)	(86,874)	(86,793)	(86,747)	(86,734)	(86,755)	(86,806)	(86,886)	(86,995)	(87,132)	(87,295)
Total Net AMI-related Rev Req Impact	**85,277**	**58,018**	**42,305**	**26,468**	**31,318**	**4,525**	**(10,837)**	**(21,492)**	**(22,081)**	**(15,744)**	**(20,826)**	**(20,469)**	**(21,334)**	**(22,143)**	**(22,949)**	**(28,354)**
Avg Monthly Customer Dollar Impact	**1.48**	**0.99**	**0.71**	**0.44**	**0.51**	**0.07**	**(0.17)**	**(0.34)**	**(0.34)**	**(0.24)**	**(0.32)**	**(0.31)**	**(0.32)**	**(0.33)**	**(0.33)**	**(0.41)**
Scenario 21 - Partial-DRR-Zone4-CPP-FV																
AMI Meter Installation Revenue Requirements	98,999	89,414	89,339	90,508	97,687	93,482	82,193	71,649	71,236	77,770	72,944	73,576	73,048	72,545	72,072	67,043
Stranded Cost Revenue Requirement - 5 year	15,627	14,629	12,804	6,640	14,107	0	0	0	0	0	0	0	0	0	0	0
Less:																
Expected O&M Reductions	(1,033)	(3,209)	(4,939)	(5,100)	(5,404)	(5,491)	(5,696)	(5,888)	(6,111)	(6,319)	(6,556)	(6,780)	(7,036)	(7,233)	(7,430)	(7,642)
Meter Revenue Requirement in Rates	(275)	(349)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)	(460)
Expected Procurement Reductions	(28,041)	(42,772)	(54,747)	(65,434)	(74,930)	(83,329)	(87,202)	(87,126)	(87,085)	(87,078)	(87,104)	(87,160)	(87,246)	(87,361)	(87,504)	(87,672)
Total Net AMI-related Rev Req Impact	**85,277**	**57,714**	**41,997**	**26,155**	**31,000**	**4,201**	**(11,165)**	**(21,825)**	**(22,420)**	**(16,087)**	**(21,176)**	**(20,824)**	**(21,695)**	**(22,509)**	**(23,321)**	**(28,731)**
Avg Monthly Customer Dollar Impact	**1.48**	**0.99**	**0.71**	**0.44**	**0.51**	**0.07**	**(0.18)**	**(0.34)**	**(0.35)**	**(0.25)**	**(0.32)**	**(0.31)**	**(0.32)**	**(0.33)**	**(0.34)**	**(0.41)**

Appendix A

Summary of Potential Benefits – Partial (Zone 4) AMI Deployment

APPENDIX A

SUMMARY OF POTENTIAL BENEFITS PARTIAL (ZONE 4) AMI DEPLOYMENT

Table 4-35 summarizes the total estimated benefits we expect will result from the partial (Zone 4) deployment[35] of AMI in the Operational-Only and demand response scenarios.

Table 4-35
Summary of Benefits under Partial Deployment
(2004 Pre-Tax Present Value Dollars in Millions)

Benefit Categories	Partial Deployment Operational-Only (Scenario 14)	Partial Deployment With Demand Response (Scenarios 16 through 21)
Systems Operations Benefits	29.3	29.3
Customer Service Benefits	1.1	4.0
Management and Other Benefits	11.3	12.5
Demand Response Benefits	-0-	Range from 18.5 to 474.5
TOTAL:	41.8	Range from 64.4 to 520.3

All benefit codes identified in the Ruling are discussed in the following sections, whether included in the revised preliminary analysis or not.

A. System Operations Benefits (SB-1 through SB-13)

Appendix A of the ACR identified thirteen 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 thirteen 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

[35] Benefits resulting from full deployment of AMI are discussed in Volume 3, Appendix A.

not able to quantify at this time. The remaining seven potential areas of benefit identified in the ACR are either already being experienced by SCE, have associated costs that more than offset the anticipated savings, or otherwise do not apply.[36]

All identified System Operations Benefits are the same for the demand response scenarios as for the operations-only scenario. The following sections address all thirteen of the potential system operations benefits as described in the Ruling.

1. 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 thirty-two 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 seventy percent of all meters in Zone 4 (70% 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 forty Meter Readers.[37] 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 thirty hand-held meter reading devices. This savings is reflected in benefit code MB-1.

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[36] 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.

[37] 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.

2. 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.

3. (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 the AMI demand response scenarios, 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.

4. **(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 4-36 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 4-36
Reduced Phone Calls

Year	2006	2007	2008	2009	2010	2011
Partial Deployment	0	2,216	2,216	2,216	2,216	2,216

5. (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.[38] 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.

6. (SB-6) Outage Management Benefits

This potential benefit has been addressed in the Business As Usual case in Volume 2 as follows: "Because we already have adequately functioning OMS, TLM, and SCADA systems, we already obtain associated benefits in our T&D

[38] SCE's Meter Infrastructure Replacement program is described in SCE's 2006 GRC Application in SCE4 Vol. 2, Chapter V.

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."

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.

7. (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.

8. (SB-8) Remote Service Connect / Disconnect

We respond to over one million turn-on/turn-off service requests annually, and we disconnect and reconnect nearly one 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. In 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.

9. (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

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 AMI (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 all full deployment demand response scenarios (Scenarios 3 through 8).[39] No similar benefit has been included for partial AMI deployment.

Benefits derived from improved “billing accuracy” are discussed below under benefit code CB-1.

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[39] *See* Volume 3, Appendix A, Benefit Code SB-9 discussion.

10. (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 eighty to eighty-five 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 AMI to create any incremental benefits in this area.

11. (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.

12. (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).

13. (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. Under the demand response scenarios, 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 the Operational-Only scenarios, 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.

B. Customer Service Benefits (CB-1 through CB-13)

The ACR identified thirteen "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 $1.1 million in the operational only scenario (Scenario 14) and $4.0 million in the demand response scenarios (Scenarios 14 through 21). 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 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 thirteen potential Customer Service Benefits under partial AMI deployment.

1. (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 all partial deployment scenarios over the duration of the analysis period.

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

2. (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 ten percent of our single-service no-lights calls. This is because approximately ten 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.

3. (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.

4. <u>(CB-4) Improves Billing Accuracy – Reduced Estimated Reads / Estimated Billing – Reduced Exception Billing Processing.</u>

Any potential cost savings for this benefit code have been included in the estimate for benefit code CB-1 above.

5. <u>(CB-5) Customer Energy Profiles for EE / DR Targeting (Marketing)</u>

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.

6. <u>(CB-6) Customer Rate Choice / Customer Rate Options</u>

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.

7. <u>(CB-7) Customized Billing Date</u>

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 improved customer satisfaction and this is very hard to attach a value to. 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.

8. (CB-8) Energy Information to Customer Can Assist in Managing Loads

Though not applicable to the Operational-Only scenarios (Scenarios 1 and 14), we do expect a direct benefit of approximately $2.9 million in each of the partial deployment demand response scenarios 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.

9. (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.

10. <u>(CB-10) Load Survey – AMI Systems Allow Utilities to Perform Load Surveys Remotely and No Longer Require Recruitment and Site Visits</u>

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.[40]

11. <u>(CB-11) On-line Bill Presentment With Hourly Data / More Timely and Accurate Information About Electricity / Information Access</u>

See discussion under benefit code CB-8.

12. <u>(CB-12) Value to Customers of More Timely & Accurate Bills</u>

See discussion under benefit codes CB-1, CB-4 and CB-7.

C. <u>Demand Response Benefits</u>

The 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

d) DR-4: Avoided/deferred transmission and distribution (T&D) additions / upgrade costs

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[40] *See* Vol. 3, Appendix A, under benefit code CB-10

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 Volume 2, Section III, B, 4.

D. Management and Other Benefits

Only two of the ten potential "Management and Other" benefit codes identified in the Ruling were actually used in SCE's revised preliminary analysis. The following sections describe our review of each of the potential Management and Other benefit codes.

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

For the partial deployment scenarios, thirty 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.

2. (MB-2) Reduced Miscellaneous Support Expenses (Including Office Equipment And Supplies)

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

3. (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.

4. (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 (Vol. 2, Section 2.B.3.c) 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 all AMI 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 the partial deployment scenarios, this avoided cost is $10.5 million over the duration of the analysis period.

5. **<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 partial deployment, we don't 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.

6. **<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 twenty-five watts) than do existing electromagnetic meters. Most electromagnetic meter discs sit "idle" when less than twenty to twenty-five 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% 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 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. Taken on its own, this technical characteristic of electronic meters would add four megawatts of load twenty-four hours a day, 365 days per year. This would add over three million kWh per year in energy consumption for the partial deployment scenarios.

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 thirty to sixty 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.

7. <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.

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

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.

9. <u>(MB-9) Tariff Planning – More Flexibility of Rate Contacts & Options Within Standard Customer Rate Classes / Dynamic Tariffs</u>

See discussion under benefit codes SB-5, SB-13 and CB-6.

10. <u>(MB-10) Potential for Tax Savings from Federal Investment Tax Credits</u>

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.