Application No.:	A.05-03-
Exhibit No.:	SCE-4
Witnesses:	D. Berndt P. De Martini R. Garwacki D. Kim L. Oliva C. Silsbee M. Whatley

SOUTHERN CALIFORNIA EDISON

An *EDISON INTERNATIONAL* Company

(U 338-E)

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

Volume 4 - Appendices

Before the

Public Utilities Commission of the State of California

Rosemead, California

March 30, 2005

Volume 4 - Appendices

Table Of Contents

Appendix A

Witness Qualifications

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF DAVID L. BERNDT

Q. Please state your name and business address for the record.

A. My name is David L. Berndt, and my business address is 2131 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the manager of Meter Strategy Integration in the Customer Service Business Unit. My primary responsibilities are planning, supervising staff, and supervising projects involving the metering process and the selection of new meter types.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science degree in Chemical Engineering from the California Polytechnic University at Pomona in 1986. I have been with SCE for 13 years and have worked in various supervisory and management positions in the Customer Service Business Unit, including positions as a field engineer, product manager, and service center superintendent.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibits SCE-2, SCE-3, and SCE-4 *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY OF PAUL J. DE MARTINI

Q. Please state your name and business address for the record.

A. My name is Paul J. De Martini, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the AMI program manager for Information Technology. My responsibilities include managing the development of the information technology business case. I also lead the development of the Information Technology product lifecycle management competency.

Q. Briefly describe your educational and professional background.

A. I am currently a Fellow of the Wharton School at the University of Pennsylvania and received a Master of Business Administration (M.B.A) degree from the University of Southern California and a Bachelor of Science (B.S.) degree in Applied Economics from the University of San Francisco. I completed a Certificate, with distinction, in Project Management from the University of California, Berkeley. I have twenty-seven years of combined experience in utility and unregulated energy services operations, systems development, cost estimating, product development and business development. I have been at Southern California Edison for over two years. Relevant experience prior to joining Southern California Edison, I was Vice President of the Energy Strategy practice at ICF Consulting in 2000-2002 with a focus on demand response, advanced metering and distributed generation technologies. Earlier, I was Vice President of Integrated Services at PG&E Energy Services in 1996-1999, and at Pacific Gas and Electric

Company from 1977-1995, where I held a number of managerial positions involving electric systems operations, project management, and project cost estimating and project risk analysis.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibits SCE-2, SCE-3, and SCE-4, entitled *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF JOHN R. FIELDER

Q. Please state your name and business address for the record.

A. My name is John R. Fielder, and my business address is 8631 Rush Street, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am Senior Vice President of Regulatory Policy and Affairs. My organization is responsible for regulatory policy and matters involving state and federal regulatory bodies.

Q. Briefly describe your educational and professional background.

A. I received a Master of Business Administration from UCLA in 1970 and a Juris Doctor Degree from Pepperdine University in 1978. I am a member of the State Bar of California.

Upon graduation from UCLA in 1970, I was employed by the Organization and Procedures Department of Southern California Edison. Three months later I was called to active duty in the Army and served three years. I returned to Southern California Edison and joined the Data Processing Department (now Information Technologies). I held supervisory positions in Administration, Quality Assurance, and Technical Support. In 1987, I became Manager of Information Technologies, and on January 1, 1989, Vice President responsible for Information Technologies. On February 1, 1992, I assumed my current position.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE-1, entitled *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF RUSSELL D. GARWACKI

Q. Please state your name and business address for the record.

A. My name is Russell D. Garwacki, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. My current responsibilities include managing the Load Research and Rate Design functions within SCE's Regulatory Policy and Affairs (RP&A) department.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Arts degree in Economics from Whittier College in 1980 and a Master of Arts degree in Economics from Claremont Graduate School in 1983. I have been employed by SCE since 1983. From 1983 to 1993, I worked in the load research area of RP&A, ultimately supervising the group. During that time, I gained an understanding of sample design, cost allocation, and other regulatory policies and procedures. In 1994, I joined the Customer Service Business Unit (CSBU) as the Credit Analysis Manager, working to reduce both write-off and credit operational costs. From 1997 to 1999, I managed the Measurement and Efficiency group, delivering process improvements for CSBU's Field Services, Credit, Payment, and Customer Communication Center functions. From 1999 to 2004, I managed various CSBU activities including Job Skills Training, Internet Delivery, Benchmarking, and various technical support functions. In 2004, I returned to RP&A to assume my current responsibilities.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE-4, entitled *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY
OF DOUGLAS H. KIM

Q. Please state your name and business address for the record.

A. My name is Douglas H. Kim, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the project manager of the AMI business case project in the Customer Service Business Unit. My primary responsibilities are work-planning, developing methodology, framework and analyses for the AMI business case; and managing the overall project activities.

Q. Briefly describe your educational and professional background.

A. I received a Master of Business Administration (MBA) degree from UCLA Anderson School of Management in 1996 and a Bachelor of Science degree in Engineering from Harvey Mudd College in 1982. I joined Edison International in 1996 to work in the corporate strategic planning and new business development group. My primary responsibility was to work as an internal business consultant for various projects across different Edison businesses. I joined SCE in 2001 and have since been primarily involved in business planning and various analytical activities.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibits SCE-1, SCE-3, and SCE-4 entitled *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?
A. Yes, it was.
Q. Insofar as this material is factual in nature, do you believe it to be correct?
A. Yes, I do.
Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A. Yes, it does.
Q. Does this conclude your qualifications and prepared testimony?
A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF LINDA R. LETIZIA

Q. Please state your name and business address for the record.

A. My name is Linda R. Letizia, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company (SCE).

A. I am a Manager of Special Regulatory Projects in the Regulatory Policy and Affairs Department, and have responsibility for the management, development, and presentation of various ratemaking showings before the California Public Utilities Commission.

Q. Briefly describe your educational and professional background.

A. I graduated from the University of California at Davis in 1980 with a Bachelor of Science degree in Mathematics. I have been employed by Southern California Edison Company since 1984. Since joining SCE, I have held various positions in the Regulatory Policy and Affairs Department. My responsibilities have included revenue allocation and rate design, the preparation of pricing studies and analyses, and the development of revenue requirements and ratemaking proposals for numerous regulatory proceedings before the California Public Utilities Commission. I have also been employed in the Capital Recovery Section and Corporate Budgets Section of the Controller's Department.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibits SCE-2 and SCE-3, entitled *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF LAWRENCE M. OLIVA

Q. Please state your name and business address for the record.

A. My name is Lawrence M. Oliva, and my business address is 22 Via Del Tesoro, San Clemente, CA, 92673.

Q. Briefly describe your present responsibilities.

A. I am Managing Director of Corepoint Associates, Inc., and provide consulting services to clients in the energy sector.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science degree in Civil Engineering from Southern Methodist University in 1972. I completed all required course work toward a Masters of Architecture degree in Urban Design at Virginia Polytechnic Institute and State University in 1974. I began my consulting career in 1974 with SCS Engineers, Inc., and worked as a staff engineer on consulting assignments in the energy and environmental field for the federal government. I joined Resource Planning Associates in 1977 as an Associate and provided consulting services to the U.S. Department of Energy and private clients. In 1984, I joined Putnam, Hayes and Bartlett, Inc., and provided consulting services primarily to electric and gas utilities in a variety of areas including power plant economics, power contracts and alternative energy. I became a principal in the firm in 1987. In 1995, I joined Arthur Andersen, LLP, as a principal and was elected to the partnership in 2001. I provided consulting services and led consulting practices for the firm in electric utility deregulation and transmission organization transformation. In 2002, I joined Navigant Consulting, Inc. as a Managing Director and led a consulting practice in transmission organization development. In 2003, I founded Corepoint Associates, Inc., and provide consulting services to clients in the energy industry.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibits SCE-3 and SCE-4, entitled *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF CARL H. SILSBEE

Q. Please state your name and business address for the record.

A. My name is Carl H. Silsbee, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am Manager of Regulatory Economics in the Regulatory Policy and Affairs Department. In this position, I am responsible for marginal cost studies and related studies to support rate design, performance based ratemaking, and a variety of special projects. I have held the position since November 1985.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor's degree in Engineering from Harvey Mudd College in 1974 and a Master's degree in Engineering-Economic Systems from Stanford University in 1975. I joined Southern California Edison in 1981. Prior to my present position, my responsibilities have included coordinating and preparing operating and maintenance expense forecasts for general rate cases, preparing revenue requirement analyses in support of Certificate of Public Convenience and Necessity (CPCN) applications, and filing, avoided cost pricing for qualifying facilities and supporting wholesale rate case applications before the Federal Energy Regulatory Commission.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE-4, entitled *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure*

Deployment Strategy and Cost Recovery Mechanism, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY OF MICHAEL A. WHATLEY

Q. Please state your name and business address for the record.

A. My name is Michael A. Whatley, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the Integrated Planning Manager in SCE's Resource Planning & Strategy group. In that capacity, I am responsible for managing aspects of SCE's Long Term Resource Plan (LTRP) and directing scenario analyses in support of the LTRP. My position also requires me to provide recommendations on emerging issues including forecasts for needed generation, economic evaluation of new supply-side and demand-side resources, and establishing long-term market price forecasts and scenarios.

Q. Briefly describe your educational and professional background.

A. I earned my Bachelor of Science in Nuclear Engineering from the University of California, Santa Barbara. I have over 12 years experience in the California energy sector addressing natural gas and electric power issues. I joined SCE in March 2003 as Integrated Planning Manager. I have previously held the position of Manager, Systems Dynamics for Edison Mission Energy where I conducted technical analyses for various business development opportunities. I have also held positions in Edison International's Strategic Planning & New Business Development group, in SCE's Energy Supply & Marketing department and for SCE at the San Onofre Nuclear Generating Station.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE-4, entitled *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF LYNDA L. ZIEGLER

Q. Please state your name and business address for the record.

A. My name is Lynda L. Ziegler, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. As Director of the Customer Programs and Service, I am responsible for market research, strategy and business planning for the customer service business unit, regulatory, customer satisfaction and communication, market management and communication, electric transportation, consumer affairs, energy efficiency and load management programs, as well as program/product development.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science degree in Marketing from Cal State University, Long Beach, in 1982, and an MBA from Cal State University, Fullerton, in 1988.

From 1973 through 1978, I was a District Manager with Skil Power Tools in charge of a million dollar sales territory. From 1978 to 1981, I was a Marketing Account Executive, developing marketing and sales promotion campaigns for various consumer goods corporations.

In 1981, I joined the Southern California Edison Company. I have held a number of different positions, several in the energy-efficiency arena. I have been a program planner, a field supervisor, major account executive, and

Manager of Energy Efficiency Programs. Outside of the energy-efficiency and demand response arena, I have served as a Customer Service Manager, Service Planner, and Credit Manager.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE-1, entitled *Testimony of Southern California Edison Company Supporting Application for Approval of Advanced Metering Infrastructure Deployment Strategy and Cost Recovery Mechanism*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

Appendix B

AMI Technology Selection Assumptions for Business Case Analysis

APPENDIX B

AMI TECHNLOGY SELECTION ASSUMPTIONS FOR BUSINESS CASE ANALYSIS

In Attachment A to the July 21, 2004 Ruling, we were required to design our business case around certain functional requirements of the meters and supporting network, which included specific a number of required technological and operational functionalities. This section describes our chosen metering and communications infrastructure solution and how this solution was selected. Additional details of the selected technology and how it would be applied in the two best scenarios is included in the business case analysis in Volume 3. This appendix only describes the technology used in our business case analysis and does not describe the technology selection for our proposed Advanced Integrated Meter development project.

The selection of an appropriate AMI technology is fundamental to the business case analysis required by the Commission. AMI system design should appropriately balance technology risk with our primary obligation as a utility whose principal objectives include operational and customer service excellence. Because the AMI system will be a key part of SCE's core business transactions system, only proven technologies with significant and successful field testing should be considered for deployment in the AMI business case analysis.

A. Background on Technology Selection Process

In order to identify the appropriate AMI system for this business case analysis, we issued a vendor Request for Information to 23 potential respondents who have some level of experience with various metering and communications technologies. For confidentiality reasons and to avoid negatively impacting a possible future bid, we will not be disclosing the names of the vendors or any identifying details of their RFI responses. In the RFI, we required that the AMI solution must conform to the guidelines established by the WG3

Functional Requirements sub-team. A high-level summary of our interpretation of these guidelines is provided in Table B-1 below:

Table B-1
Summary of Required Functionality

Elements	Description
Estimated Meter Quantity	Residential: 3,962,000 < 20 kW C&I: 586,621 20-199 kW C&I: 143,787
Data Interval	From 15 minute to hourly increments
Collection Methods	Remote with manual read capability
Collection Frequency	Daily with on-demand read capability. Customer access to personal energy usage data with sufficient flexibility to ensure that changes in customer preference of access frequency do not result in additional AMI system hardware costs
Data available to Customer	Previous days data available to SCE next day by 8:00 a.m./Same day (near real-time) capabilities for subset of customer population
Customer Data Interface capabilities	KYZ output and/or other near real-time usage data presentation capability
Remote meter programming capability	Required

In response to our RFI, we received proposals from 18 vendors. Once the proposals were received, we used criteria identified in the RFI to evaluate the responses, as set forth below in Table B-2. These criteria are important because they are fundamental to balance system cost and service excellence. The criteria were weighted based on our experience in developing and deploying past technology solutions. A cross-functional team of SCE subject-matter experts was assembled to assess the vendor responses. The team addressed information gaps that, if unresolved, could significantly expose our ratepayers to unnecessary risk. Select vendors were contacted and provided with the opportunity to respond.

It is important to note that none of the 18 vendors contacted provided a response claiming commercial availability of a fully-integrated ("under the cover") metering solution with two-way ALC interface with end-use devices such as AC thermostats (providing set-back functionality rather than operating as an on-off load switch). In fact, the majority of the respondents claimed that their AMI solution would be compatible with and/or would possess the ability to interact with future (*i.e.*, yet to be developed) modules that could facilitate ALC and/or in-home usage information devices. A handful of respondents did have commercially available load switches (on/off capable) to control one or more end-use devices, but these would not be categorized as possessing ALC functionality. A real ALC technology option with integrated ALC does not yet appear to exist.

From this RFI process and based on the evaluation criteria, we selected the most appropriate technology based on the July 21, 2004 Ruling's required functional specifications.

Table B-2
AMI Request for Information Criteria

Evaluation Criteria	Description	Weighting
Reliability	The AMI technology solution's capability of ensuring data is not lost in the event of a component failure. Adequate redundancy needs to be balanced with cost considerations to maximize cost effective, reliable performance.	30%
Functional Requirements	The conformity of the AMI technology solution's functionality with the functional requirements of the RFI.	30%
Expected coverage	The AMI technology solution should reach at least 90% of SCE's customer base.	20%
Adherence to SCE (IT)	The ability of the AMI technology solution to reduce project complexity, costs, and risks.	20%

Standards		

B. Selection of Radio Frequency Technology Solution

Based on the evaluation process discussed above, we selected a balance of technological maturity and the technology solution's ability to leverage our existing communications infrastructure assets. Other technological solutions, such as power line carrier and other RF solutions, have some appeal but are not yet proven at the required scale, are still in the developmental stages, do not possess the data transmission capabilities, or are not available within the timeframe required by the Commission's business case parameters.[1]

The RF technology selected for the business case analysis had the greatest amount of flexibility and scalability given the various deployment strategies under consideration in this proceeding. In addition, this RF technology leverages our existing communications and metering systems. Our distribution system currently has a network of approximately 30,000 radio devices already installed and operational that are used for distribution management and interval metering purposes. From the vendors' responses, we understand that this solution has the ability to provide some level of protection against data loss generally meets the functional requirements of the RFI and is capable of reaching 90 percent of our customers. It also appears to reduce project costs and complexity in comparison to other solutions.

The selected business case technology will require that we replace all residential and small commercial meters with new solid state meters. Using a different RF technology that would allow retrofitting of a subset of existing meters was not found to be a more favorable alternative, given that retrofitting adds to the complexity of an already aggressive deployment schedule without providing any real cost advantage. Based on our experience in attempting to retrofit existing meters for the AMR program, we learned that retrofitting adds

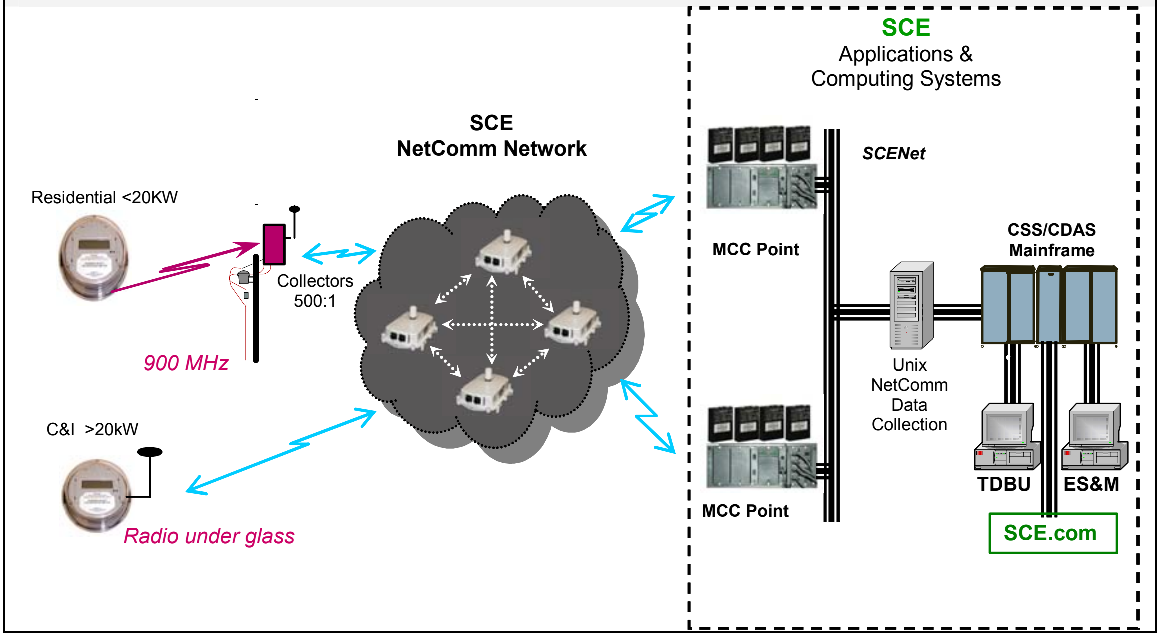
[1] For example, we recently attempted to test several metering solutions, but learned that some promised components are still under development and may be as many as 12-18 months away from delivery for testing purposes.

substantial complexity and operational cost, including retrofit compatibility issues, higher incidences of failures, and additional handling requirements. Based on the cost estimates for both solutions, we found there was no significant economic benefit to a retrofit solution compared to simply replacing all meters with new solid state technology and leveraging our existing RF network assets.

The AMI technology solution selected for the business case analysis uses two RF technologies; one for residential meters and commercial meters less than 20 kW and one for greater than 20 kW meters. Meters using the first RF technology will be equipped with a radio that communicates with a "collector" to form a Local Area Network (LAN). The collectors will be mounted in the power space of a utility pole or streetlight and will typically communicate with meters within a 400 to 700 meter distance.[2] The greater than 20 kW meters will be equipped with radios under the meter cover and will communicate directly with the network. The two RF technologies are illustrated in Figure B-1.

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

Figure B-1
Illustration of Selected RF Technology



The Wide Area Network (WAN) is made up of the existing network, the addition of new radio devices, and the 20 kW and above meters equipped with radios. Each end-device radio generates a "packet" of data that travels the network by "hopping" from radio to radio in the direction of the destination-addressed radio. The route chosen for traveling the network is dynamic and employs an automatic rerouting system. This system automatically minimizes the amount of "hops" between the radios, which increases the transmission speed of the data packets. The packet is "addressed" to the communication controller take out point. Each point is connected to the SCE network.

The RF technology uses two distinct types of radio transmission spectrum technology to collect and send meter data. The residential and less than 20 kW commercial meters use a "direct sequence" spectrum technology. This technology typically provides a range of up to 0.5 miles from the meter to the collection device. The technology is one-way, from the meter to the collector. The 20 kW and above commercial meters use a "frequency hopping" spectrum technology in a license-free area of the radio spectrum. This technology provides a range of up to 5 miles. The technology will be deployed in two ways. In some cases, it will be under-the-cover of the meter, typically mounted at approximately five feet high. In other cases, it will be within the collection device normally mounted at a height of 20 to 30 feet. This technology is also peer-to-peer[3] and provides an unlimited number of "data hops." This system is designed to be able to maintain high levels of reliability.

The selected RF technology meets the Ruling's functional requirements among the alternatives considered. This same technological solution would be used for a partial case scenario, but scaled down in size to the targeted geographical area. The details of how this was scaled down are provided in the business case scenario analysis described in Volume 3.

C. AMI Technology Failure

Our technology solution uses solid state metering with electronic components. Throughout the course of the AMI deployment and thereafter, the solid state meters and associated communications infrastructure will experience some level of failure. This failure can be attributed to the actual hardware components failing and/or technology related (*i.e.,* RF) interference impeding meter data communications. These failures will likely result in a required field visit to the meter location to attempt to identify the source of the problem and may require additional investigation. Hardware failures may include one or more of the solid state meter components, the RF communications module, and/or the "collector" device, all of which comprise the LAN communications infrastructure. Hardware failures may be attributed to one of multiple causes, including manufacturer design flaws, defective material provided by other third party manufacturers or vendors (components used to build the meters and communications equipment), and/or defects in workmanship related to the assembly and construction of these components.

Based on our experience with testing new meter technology and with other solid state meter remote communication deployments, it is expected that a higher "meter" failure rate

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

(AMI technology failure rate of the LAN components) will be experienced than the level of failures associated with our existing mechanical meters. We experienced a high level of equipment failures in our recent RTEM and SPP deployment due to communications and hardware problems.

Over a three-year period, from 2001 through 2004, we purchased approximately 16,000 remotely communicating interval meters. The meters were used in both the RTEM and the SPP projects. The remote communication technologies deployed for these projects included wireless pagers, wireless radios (RF technology), and/or wired phone lines. Since initial deployment in 2001, approximately 48 percent of the 16,000 meter population has been returned for warranty repair. Meter recalls due to design or material defects accounted for 66 percent of these failures. The remaining 34 percent can be attributed to a combination of various material and workmanship related issues. These combined problems translate to an overall average annual failure rate of 16 percent for our RTEM meters throughout this time period.

For the AMI preliminary business case analysis submitted in January 2005, we assumed a lower failure rate than that observed in our RTEM experience. Even though the rapid and wide-scale deployment envisioned under the full deployment scenarios, combined with potential competition for limited metering hardware may cause a higher incidence of product-related problems, we used an estimated failure rate that decreases over time. Our estimated failure rate is higher in the early deployment years, continuously declining until a steady state is reached in the fifth year of the five-year deployment. The average annual failure rate projected over the entire static meter population for the business case analysis is approximately two percent. The impacts from these failures will affect multiple organizations including our Customer Communications, Billing, FSMRO, and Electrical Metering Services organizations.

D. Staging and Development of Applications

The July 21, 2004 Ruling's required five-year meter deployment schedule is aggressive and thus, would require that much of the communications infrastructure deployment and development of IT applications occur simultaneously. As a first priority, we would plan to focus on developing support applications for our supply chain management and meter installation work flow management functions that would necessarily need to be operational before any meter deployment could take place. In order to deploy AMI meters beginning in 2006, we would need to start developing these applications beginning early in 2005. All other remaining applications necessary to support AMI would start being developed in 2006 and would not be operational until mid 2007. The communications infrastructure would start being deployed in 2006 and would not be operational until mid 2007 as well. Deployment of the infrastructure will continue to fill in any coverage gaps identified during the remainder of the five-year period to achieve the 90 percent coverage.

Appendix C

Demand Response Approach and Assumptions

APPENDIX C

DEMAND RESPONSE APPROACH AND ASSUMPTIONS

A. Demand Response Approach and Assumptions

In this Appendix, we describe our approach and key assumptions for estimating demand response benefits from time-differentiated rates (TDRs) enabled by AMI. We followed the guidelines provided by the July21, 2004, and November 24, 2004 Rulings including the framework for demand response scenarios, prescribed assumptions and demand response benefit categories. Our January 12, 2005 preliminary filing presented our approach and results for all required scenarios. This analysis relies on the same general methodology for the best full and best partial deployment cases, but updates certain assumptions from newly available data.

This section is divided into four subsections. First, we describe the key factors and assumptions which support our demand response benefit analyses. In the second subsection, we provide an analysis of the effect of 1-in-10 weather on demand response benefits. In the third subsection, we describe our analysis of the impact on total annual energy use for each scenario. In the fourth subsection, we explain our analysis of the cost-effectiveness of enabling technology based on Summer 2004 results in the Statewide Pricing Pilot (SPP).

1. Key Factors and Assumptions in Estimating Demand Response Benefits

Demand response benefits are driven by four key factors:

- Rate Design and Bill Impact Assumptions - Rate design and bill impacts drive both customer adoption and customers' responsiveness to TDRs.
- Customer adoption of TDRs - Customer adoption in our best-case scenarios was based on opt-out enrollment assumptions provided by the July 21, 2004 Ruling. Customer enrollment in a dynamic rate was a necessary condition for assuming price responsiveness.

- Customer responsiveness to TDRs – The SPP provided observed measurements of customer behavior to dynamic pricing. This provided the basis for estimating demand response of SCE customers under business case scenario-specific assumptions. Adjustments were made to account for SCE customer-specific characteristics, statistical modeling variance and probability, and enrollment methods.
- Value of demand response - Load reductions as a result of TDRs can provide avoided resource value.

Each of these factors is addressed in turn below.

a) Rate Design and Bill Impact Assumptions

Consistent with the July 21, 2004 Ruling, TDRs used in the AMI business case scenarios for residential, small commercial, and medium commercial/industrial customers were designed to be revenue neutral to their respective otherwise applicable tariff (OAT). For each rate class, rates were designed with TOU periods consistent with existing or experimental CPP rate structures. The design structures are summarized in Table C-1 below and the process we used to analyze our proposed rate design and bill impact analysis is discussed in detail in Appendix K.

Table C-1 Experimental/Existing CPP Rate Structures			
	RES	GS-1	GS-2
Existing CPP Tariff =>	TOU-D-CPPF	TOU-GS-1-CPPV	GS-2-TOU-CPP
On-Peak/CPP Event =>	S/W: 2pm-7pm	S/W: Noon-6pm	S: Noon-6pm
Season-Months =>	S/W - 6/6	S/W – 4/8	S/W - 4/8
Rate Structure =>	S/W: On/Off	S/W: On/Off	S: On/Mid/Off W: Mid/Off
	Proposed AMI CPP Rate Structures		
	RES	GS-1	GS-2
On-Peak/CPP Event =>	S/W: 2pm-7pm	S/W: Noon-6pm	S/W: Noon-6pm
Season-Months =>	S/W - 6/6	S/W – 4/8	S/W - 4/8
Rate Structure =>	S/W: On/Off	S/W: On/Off	S: On/Mid/Off W: Mid/Off

Under CPP-F, residential customers are subjected to 5 hours per daily CPP event between the 14:00 and 19:00 hours. Commercial customers under CPP-V are subjected to three hours per CPP event day, between the 12:00 and 18:00 hours. Using 2003 annual rate group load data, CPP "events" were defined with 100 percent certainty to occur on the system peak demand days. This is an unlikely scenario, but we did not make adjustments in rates to account for this level of uncertainty. Uncertainties of this type are more appropriately included as a de-rating factor associated with the value of the demand response. Reducing the value of the demand response, and hence the CPP rate, could be an appropriate refinement but we did not make that adjustment because it would only serve to reduce the demand reduction associated with a lower CPP rate.

CPP "adders" were based on an $85/kW-year capacity cost divided by the number of hours subject to the CPP-F peak period prices. CPP peak rates for rate schedules with fewer hours were capped at the CPP-F levels as they already exhibited a fairly high ratio relative to their otherwise applicable summer on-peak rate (6:1 in the case of non-AB1-X compliant CPP-F residential rates).

In addition to the above longer-term non-AB1X environment described above, an additional short-term AB1X environment analysis is also contained in Appendix K. In that scenario, the net impacts of financing capital cost additions and net operational cost impacts are included in the rate group bill impacts.

CPP rates and bill impacts were used in calculating demand response and customer acceptance of TDRs. The CPP rate was used to estimate peak load impacts. The bill impacts were used in the Momentum Market Intelligence (MMI) model of customer adoption of TDRs.

b) Approach to Estimating Customer Adoption of TDRs

Customer adoption of Critical Peak Pricing over the study period is difficult to estimate because no utility has implemented such rates over a long period of time. For analysis purposes, we used sustained adoption rates required by the July 21, 2004 Ruling for Opt-out (default tariff) enrollments of 80 percent. We assumed that customers who opt-out of the default rate were assigned an adoption rate in equal proportions to other tariff alternatives. For example, in Scenario 4, we assumed that 80 percent of eligible customers default to a CPP-F rate and assumed that 10 percent opt-into a TOU rate and 10 percent opt-into their current rate.

For large customers (>200kW) we assumed that all customers were placed on a two-part RTP rate on a mandatory basis. In Scenario 12, we assumed that all large customers are placed on a two-part RTP rate. In Scenario 13, we assumed that customers currently on Schedule I-6 would stay on that program and all others are placed on a two-part RTP rate. Our analysis of demand response impacts from two-part RTP (*i.e.,* Scenarios 12 and 13) is discussed in Appendix I.

Our customer adoption rates assumed for the business case scenarios in this filing are shown in Tables C-2, C-3 and C-4 below.

Table C-2 Residential Customer Tariff Adoption Rates by Business Case Scenario						
Scenario	**Default Tariff**	**Other Tariffs**	**Full or Partial Deploy-ment**	**TOU**	**CPP-F**	**Current**
4	CPP-F	TOU or Current	Full	10%	**80%**	10%
17	CPP-F	TOU or Current	Partial	10%	**80%**	10%

The percentages in bold indicate assumptions required by the Ruling. Percentages are of total residential meters.

Table C-3 GS-1 C&I Customer Tariff Adoption Rates by Business Case Scenario						
Scenario	**Default Tariff**	**Other Tariffs**	**Full or Partial Deploy-ment**	**TOU**	**CPP-V**	**Current**
4	CPP-V	TOU or Current	Full	10%	**80%**	10%
17	CPP-V	TOU or Current	Partial	10%	**80%**	10%

The percentages in **bold** indicate assumptions required by the Ruling. Percentages are of the total of C&I customers meters.

Table C-4 GS-2 C&I Customer Tariff Adoption Rates by Business Case Scenario						
Scenario	**Default Tariff**	**Other Tariffs**	**Full or Partial Deploy-ment**	**TOU**	**CPP-V**	**Current**
4	CPP-V	TOU or Current	Full	10%	**80%**	10%
17	CPP-V	TOU or Current	Partial	10%	**80%**	10%

The percentages in **bold** indicate assumptions required by the Ruling. Percentages are of the total of C&I customers meters.

There are several reasons for a high level of uncertainty regarding long-term adoption of TDRs. First, there is only very limited experience with customer acceptance of CPP-type rates in the residential class. CPP rates have not been implemented in a mass market, other than pilots, in the United States and thus, customers are generally unfamiliar with such rates.[4]

Second, more than 40 percent of customers surveyed by SCE preferred a tiered or flat rate over time-differentiated rates.[5] While about 30 percent of customers' initial preference was a time-of-use rate, the initial preference for CPP rates was less than 10 percent.[6] It is unknown whether initial preferences predict actual enrollment either in the short run or on a sustained basis.

Third, the utilities had difficulty recruiting customers for participation in the SPP experiment. To meet minimum enrollment targets for the experiment, the utilities had to contact customers individually by telephone to get their agreement to participate in the SPP.

Fourth, the results of market research conducted in the SPP concerning the adoption of TDRs varied widely depending upon expected bill savings and customer awareness of the rate options available to them.[7]

The assumption that 80 percent of customers will indefinitely remain on CPP rates required by the Ruling also requires an assumption about customer awareness of their rate options. The research conducted in the SPP found that an initial enrollment of 80

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[4] Customers are generally familiar with peak/off peak time-of-use rates in the communications industry. However, CPP rates differ in that only certain days, when called by the utility, have very high rates. Customer notification is important and customer understanding of and reaction to that notification, good or bad, has not been examined outside of the SPP experiment where customers received incentives to participate in the program.

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

[6] *Id.*

[7] Momentum Market Intelligence, A Market Assessment of Time-Differentiated Rates Among Residential Customers in California, December 2003. See Chapter 5.

percent in CPP-F as a default rate could be reached under an assumption that only 60 percent of customers are aware of their rate options.[8] This research found that increased awareness of rate options (*e.g.*, above 60 percent) would lower the adoption of TDRs on an opt-out or default enrollment basis.[9] Over time, as customer awareness grows, adoption rates would decline, according to that research. Sustaining enrollment would be difficult. Even the CPP treatment group in the SPP that was offered financial incentives to continue to on the program in 2004 had an attrition rate of four to six percent in 2003.[10]

While CPP rates may have appeal to policy makers because high prices can elicit more demand responsiveness, customers have shown little interest in them so far. Only very few large SCE customers have signed up for the voluntary CPP tariff since it was offered in December 2003. The primary barriers to large customer participation are: 1) the effect on customer products or productivity; 2) the level of on-peak prices or non-performance penalties; 3) the relatively small amount of potential bill savings; and 4) the perceived inability to reduce peak loads.[11] Recently, the Commission concluded that voluntary CPP rates for large customers have not yielded what was expected.

> "When interval meters were installed, and voluntary critical peak pricing tariffs were put in place, we expected that the customers with these meters would provide a significant source of demand response capability. Instead, what we have found is that few customers have enrolled in the voluntary critical peak pricing tariffs."[12]

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[8] Momentum Market Intelligence. Customer Preferences Market Research, A Market Assessment of Time-Differentiated Rates among Residential Customers in California, December 2003, Table 5-3 p. 109.

[9] *Id*. P. 106

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

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

[12] Assigned Commissioner and Administrative Law Judge's Ruling Directing the Filing of Rate Design Proposal for Large Customers, December 8, 2004, R.02-06-001.

Our market research found that only 9 percent preferred CPP rates and 29 percent of customers preferred TOU rates in a SCE market research study.[13] This is similar to the SPP market research that found that the CPP-F pilot rate would yield an opt-in market share of 10 percent if 30 percent of customers had awareness of their rate options, 17 percent enrollment with 50 percent awareness, and 34 percent enrollment with 100 percent awareness.[14]

Because the market research indicates that the vast majority of customers do not prefer CPP rates, a CPP program could create a customer backlash if implemented on a default or mandatory basis. The repeal of the Puget Sound Energy's (PSE) short-lived TOU rate program is an example of what can happen when customers become dissatisfied with TDRs. When PSE provided quarterly report cards to customers showing them how much they did or did not save on their TOU rate program, many customers realized that they saved very little or even paid more on the new rate and became upset and opted out of the program. This initially resulted in a public relations problem and ultimately led to PSE's decision to cancel the program.[15]

With respect to the number of customers eligible to enroll in TDRs, we assume that all customers equipped with AMI meters would be eligible, including customers eligible for CARE rates. We ignored the legislative requirements of AB1X, as directed by Agency Staff in Working Group 3.

To sustain the 80 percent customer adoption for CPP over the study period, marketing efforts are necessary to make up for lost enrollments due to premise moving, customer dissatisfaction or customer choice of other options. We anticipate that the

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

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

[15] Williamson, Craig, "Primen Perspective: Puget Sound Energy and Residential Time-of-Use Rates – What Happened?," Energy Use Series, Volume 1, Issue 10, December 2002, p. 4.

drop-off rate per year would be significant due to higher costs, lack of savings, customer dissatisfaction or moving. Even the SPP participants who were offered an incentive payment to continue to participate in 2004 after 2003 had an attrition rate of four percent.[16]

c) Approach to Estimating Customer Response to TDRs

Our approach to estimating the amount of customer response to TDRs is based on: (1) statistically significant peak load impact results of the SPP for 2003 and 2004,[17] (2) adjustment of the SPP-measured load impact to SCE's territory, (3) adjustment for statistical model variance, and (4) differences in customer response behavior between the TDR enrollment approach in the SPP and the assumed enrollment approach in the business cases. For the first point, we relied on peak load rate impact results for the all-summer period from the SPP based on summer 2003 and 2004 data. On the second point, we used Charles River Associates Inc.'s (CRA) method and analytical simulation model to adjust SPP results for SCE's customer characteristics and service territory weather. On the third point, we adjusted the demand response estimated from the statistical models, using the standard errors produced from the modeling, to obtain an estimate of the 95 percent confidence interval. For the last point, we adjusted the average per customer demand response resulting from the previous steps to account for the fact that the average customer who is defaulted to the CPP rate under an opt-out enrollment will not behave in the same way as the customers who affirmatively opted-in to the SPP experiment. We describe this approach for each of these points further below.

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

The SPP consultant, CRA measured the observed residential customers' response to CPP-F, TOU and CPP-V rates and small C&I customers' response to

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[16] Charles River Associates, Inc., Impact Evaluation of the California Statewide Pricing Pilot, Final Report (DRAFT), February 11, 2005, p. 25. A total of 4% of customers elected to opt-out of the experiment between July 1 and October 31, 2003.

[17] *Id.*

the CPP-V rates. Based on the consultant's findings, only the CPP-F results for residential were directly applicable to the business cases. For CPP-V rates, we used a CPP-F proxy. For other tariffs we used the following proxies as described below:

(a) TOU Rates:

SPP results were inconclusive for customers on TOU rates as explained in the consultant's final report: "In short, there are reasons for taking the analysis of the TOU rate treatment with a 'grain of salt.'" Indeed, an argument could be made that the non-CPP day elasticities from the CPP-F treatment would be better predictors of the influence of TOU rates on energy demand than are the TOU price elasticity estimates."[18] Accordingly, we used the non-CPP day time of use elasticities for our analysis.

(b) CPP-V for Commercial Customers:

SPP results were inconclusive because the treatment samples were relatively small and not representative of the C&I population as a whole. As a proxy, we used a price elasticity for C&I that is 25 percent of the residential price elasticity found in the SPP. This estimate is supported by current literature.

(c) CPP-Pure for Residential and Commercial Customers:

This rate was not tested in the SPP. In our preliminary studies, we used the price elasticity for CPP-F as a proxy. CRA supports this proxy assumption. This rate was not used in our best scenarios described in this filing.

(d) Two-part RTP for Large Customers:

Two-part RTP rate was investigated in WG 2 and no conclusions or guidance on how a rate could be designed were provided. We therefore used the literature to develop an approach to large customer response to a two-part RTP. This approach is described in Appendix I to this volume.

[18] *Id.* , p. 91.

(2) Application of SPP Statewide Results to SCE Territory

There are two key components of estimating the demand response from TDRs in SCE's territory: (1) the existing energy use by rate period for customers in the target population prior to the introduction of a new rate, and (2) price elasticities, which are used to predict the change in energy use by rate period. Our approach to developing each of these components is described below.

(a) Existing Energy Use

We estimated the existing average energy use of SCE customers by climate zone and rate period for residential, GS-1 and GS-2 customers from our load research data. The average energy use was based on summer 2003 data, which is a reasonable proxy for the "average" summer for SCE. Our average energy use assumptions are shown in Table C-5 below.

Table C-5
Existing Average Energy Use by Class and SCE Climate Zone (kWh/hr)

Rate Group	SPP Climate	CPP Day		Non-CPP Week Day		Summer Week Day		Weekend/ Holiday
	Zone	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak	
Residential	2	0.67	0.53	0.63	0.50	0.64	0.50	0.55
	3	1.63	0.91	1.28	0.79	1.31	0.80	0.96
	4	1.73	1.02	1.44	0.89	1.47	0.90	1.08
GS-1	All	2.29	1.26	2.14	1.22	2.17	1.22	1.08
GS-2 < 200 kW	All	27.01	16.62	25.52	16.06	25.78	16.16	18.56

(b) Price Elasticities

The price elasticity econometric models were developed by CRA using statewide observations in the SPP for 2003 and 2004. Two summary measures of price response used in this analysis are the elasticity of substitution and the daily price elasticity of demand. As described above, the elasticities used in the analysis are based on the SPP results for CPP-F rates. The SPP elasticity data for all of California are found in Table 4-10 of the CRA February 11, 2005 report and are summarized in Table C-6 below for SCE climate zones.

Table C-6
Residential CPP-F Rate Elasticity Estimates Statewide
All Summer Averages

Climate Zone	**Elasticity of Substitution**		**Daily Price Elasticity**		
	CPP Days	Non-CPP Days	CPP Days	Non-CPP Days	Weekend Days
2	-.061	-.055	-.042	-.044	-.018
3	-.102	-.093	-.043	-.047	-.026
4	-.113	-.105	-.032	-.039	-.020

To determine price elasticities for SCE, we made adjustments based on the weather conditions (*see* Table C-7) and the central air conditioning (CAC) saturations representative of SCE populations in our Climate Zones 2, 3, and 4 (*see* Table C-8).

Table C-7
Cooling Degree Hours by Zone and Period for Normal Year

Climate Zone	**CPP Day**		**Non-CPP Day**		**Average Summer Day**	
	Peak	**Off Peak**	**Peak**	**Off Peak**	**Peak**	**Off Peak**
2	10.39	1.90	1.83	0.17	2.60	0.31
3	21.60	5.59	8.13	1.24	9.45	1.63
4	27.16	12.44	15.95	5.88	17.02	6.47

Table C-8 SCE Central Air Conditioning Saturations	
Climate Zone	**CAC Saturation (Percent)**
2	21.2
3	57.81
4	60.89
All	41.91

With the guidance from the SPP consultants, CRA, and the PRISM load reduction simulation tool, we derived load reductions for customers in our territory by making adjustments for air conditioning saturation and cooling degree hours.[19] The impact estimates for residential CPP-F and TOU TDRs are shown in Table C-9 below. As noted above, we used the impact estimates on peak for CPP-F as the proxy for CPP-V (for C&I customers equals the impact for residential times 25 percent) and the impact estimates on peak on non-CPP days for TOU.

[19] The Price Response Impact Simulation Model (PRISM) prepared by CRA and provided to SCE for use on February 11, 2005.

Table C-9 Peak Period Impact Estimates for SCE Specific Residential Tariffs Based on All Summer SPP Results					
Climate Zone	**Impact Measure**	**CPP-F Rate**		**TOU Rate**	
		CPP Day Peak	**Non-CPP Day Peak**	**CPP Day Peak**	**Non-CPP Day Peak**
Zone 2	**Change (kWh/hr)**	-0.107	-0.019	-0.019	-0.019
	% Change	-16.01	-3.09	-2.78	-2.78
Zone 3	**Change (kWh/hr)**	-0.362	-0.069	-.069	-.069
	% Change	-22.21	-5.40	-5.81	-5.81
Zone 4	**Change (kWh/hr)**	-0.366	-0.085	-0.085	-0.085
	% Change	-21.17	-5.90	-7.79	-7.79

(c) Adjustment to SPP Load Impacts for Statistical Model Variances

The issue of how much forecasted load reduction could be counted as a load modifier for resource adequacy purposes has not been determined by the Commission. For purposes of this analysis, we have taken statistically significant price elasticity estimates and applied average energy usage, average weather and average air conditioning saturation data particular to SCE to derive estimated load impacts from TDRs. We suggest that an additional statistical analysis is required to determine what load impact result from the SPP for SCE customers can be reasonably relied upon at a 95 percent confidence level.

The load pricing impacts were estimated using the CRA spreadsheet model, which applies the Elasticity of Substitution (ES) model parameters to CAC saturations and weather data for the SCE service territory. Two elasticity values are calculated, each based on three model parameters and the weather and saturation data.

These elasticity parameters are then applied to customer usage and price data for SCE's customers to arrive at the load impact during on-peak hours for each climate zone. Because these load impacts are estimates based on statistical modeling, there is uncertainty in these estimates. While there can be uncertainty from various sources, our analysis focused on the uncertainty due to the model estimation process. We did not attempt, in this step, to account for uncertainty from other sources.

The variance observed in this analysis is the variance of the average customer response. The response from any individual customer will be much more variable. Because we are looking at the total load impact (which depends on the average customer response), we are not including the individual customer load impact variability in this analysis. CRA's PRISM models included the standard errors and t-statistics by zone for all variables that were necessary to do this analysis.

We used Monte Carlo simulation to estimate the distribution of the load impacts. The simulation program (Crystal Ball) generates many replicates of a set of random variables, and then evaluates a formula based on those replicates to get a distribution of the result of the formula. Using this approach, we developed an approximate distribution for the load impact results for each climate zone. Using this approximate distribution, we also determined a one-sided 95 percent confidence interval on the load response.

The results of our Monte Carlo analysis for capacity planning in each zone are shown in Table C-10 below.

Table C-10
CPP-F Peak Load Impact at 95th Percentile

Zone	PRISM Peak kW/kWh Impact	95th Percentile Peak kW/kWh Impact
2	-.1073	-.0996
3	-.3620	-.3387
4	-.3662	-.3313

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

A critical assumption in the analysis of demand response benefits is the expected response of the population who default onto the CPP-F rate. We do not have empirical data on which to base this assumption. The SPP provided measurements of participant response to TDRs in the Impact Evaluation of the California Statewide Pricing Pilot, Final Report, prepared by CRA.[20] However, the response measured in the experiment was of customers who adopted the CPP-F rate on a *voluntary and affirmative enrollment basis*.

Importantly, this method of enrollment would likely yield average customer behavior to TDRs that is very different than customers who are enrolled by default. SPP participants were unique in that they were heavily recruited, fully informed of the rate options under the pilot, affirmatively opted-in to a rate and were paid an incentive for participation. Even under these special conditions, only a small percent of those customers initially contacted agreed to participate in the experiment. Opt-out or default enrollments result in a portion of customers who default on a rate unless they affirmatively opt out to another rate. The opt-out or default method can result in high enrollments because customer knowledge and understanding of their rate choice is not necessary. In fact, the SPP research found that high enrollments were consistent with relatively low customer awareness of rate choices under opt-out enrollment.[21] Differences in behavior between opt-in and default enrolled customers would be due to differences in interest in participation and understanding/awareness of rate options.

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[20] Statewide Pilot Project, Summer 2003 Impact Analysis Impact Evaluation of the California Statewide Pricing Pilot, Final Report, Charles River Associates, August 9, 2004February 11, 2005, (Draft).

[21] *Id.*, Momentum Market Intelligence.

Customer awareness of rate options is important because it is a key factor in price responsiveness. If the customer is not aware of the rate or price, the customer will not respond. Undoubtedly, “unaware” customers would not take affirmative steps to reduce load at peak periods in the same way as “aware” customers. SPP participants, due to the recruitment process and the affirmative actions they made to enroll in the experiment should be assumed to have full awareness of the CPP-F rate and their options. Their education and awareness in the enrollment process prepared them to respond when prices were high during CPP events.[22]

To quantify the appropriate response of all customers on the CPP-F rate at peak under an opt-out scenario, we must adjust for these customers who default to the rate unknowingly. We made this adjustment first by assigning the full portion of the SPP measured peak load reduction from the CPP-F rate to the portion of customers in a business case scenario who we estimate would have affirmatively opted-in to the CPP-F rate. Then, for the remaining portion of customers assumed to default to the CPP rate, we assigned a lower percentage of the peak load reduction measured in the SPP from the CPP-F rate. Essentially, we believe that customer responsiveness under an opt-out enrollment process is a function of customer awareness of and interest in their rate.

The way we derived the customer responsiveness for opt-out enrollment is described as follows: Scenario 4 assumes that 80 percent of eligible residential customers enroll on the CPP-F rate on a default basis. Using the MMI model developed from the SPP, we determined that about 16.8 percent of SCE’s residential customers would have affirmatively opted-in to the CPP rate if it were offered on that basis. For discussion purposes, we called this group “willing enrollments” on the CPP-F rate. Thus, the remaining 63.2 percent (80-16.8) must be customers who would not opt-out of the CPP-F rate due to inertia, perception of risk, are unaware or would not understand their rate options. In

[22] A summary of the measures to recruit and inform customers is provided in CRA’s Final Impact Evaluation of the Statewide Pricing Pilot, July 2003-December 2004, pp. 23-25.

essence, the 63.2 percent group are "default enrollments" but are assumed on the CPP-F rate nonetheless. The load impact from the "default enrollments" was not tested in the SPP or any other experiment and is unknown. The MMI work in the SPP project demonstrates that to achieve an eighty percent enrollment on an opt-out basis about half of those enrolled would be unaware of their rate options. Using this data implies that 50 percent or more of the "default" enrollments would not respond to CPP events due to a lack of awareness or understanding of the price signal.

We used a weighting factor to determine an average load impact to apply to all customers on an opt-out enrollment of CPP-F rates. For willing enrollments, we applied 100 percent of the SPP observed load reductions at the 95 percent confidence interval (*see* Table C-10 above). For the default enrollments, we applied 50 percent of the load reductions observed in Table C-10. Accordingly, on a weighted basis, we apply a 60.5 percent factor to the full SPP load impact for CPP-F on a per-customer basis for the entire population assumed to be on the CPP-F rate in Scenario 4, as shown in the table below. We applied the approach in the above example in Scenarios 4 and 17.

Table C-11
Load Impact Adjustment for Scenario 4 Using SPP Results for Summer 2003

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

The adjusted percentage load impact per customer on CPP-F rates resulting from the adjustment for opt-out enrollment and is shown in the table below.

For the Peak load reductions for the CPP-F rate on CPP days, we include the adjustment for estimating load reduction at a 95 percent confidence level (described above) because these estimates are used to determine avoided generation capacity savings, which is the bulk of the estimated demand response benefits.

Table C-12
Adjusted Residential Peak Period Load Impact from TDRs for SCE Assuming Opt-out Enrollment (Percent Reduction)

Climate Zone	CPP-F Rate	
	CPP Day	Non-CPP Day
2	8.99*	1.64
3	12.57*	3.08
4	11.58*	3.38

* Includes adjustment for 95 % confidence described above.

d) Resource Value

For all the required scenarios, the July 21, 2004 Ruling assigned a capacity value of $85/kW-yr, and energy value of $63/MWh and a congestion avoidance value of $7/MWh. We applied these estimates in all scenarios to comply with the July 21, 2004 Ruling. However, we do not believe that $85/kW-yr is the correct value to use in this analysis. Rather, we make "value adjustments" to account certain operational restrictions attributed to CPP, and uncertainties in market forecasts for supply availability and load. Our value adjustments are described in Appendix D in this volume. In sum, the July 21, 2004 Ruling's assumption for capacity at $85/kW-yr to reflect avoided reserves of 15 percent results in a value of $97.75/kW-yr. With our adjustments, we believe that the value of load reductions from CPP-F rates should be $52.70/kW-yr, which includes 15 percent for avoided reserves.

2. One-in-Ten Year Weather Analysis

As required by the July 21, 2004 Ruling, we prepared an analysis of the effect of 1-in-10 year weather on demand response benefits. Although it is interesting to note the effect of a hot year on demand response however, an average weather year is more appropriate for the business case.

We used 1997 as representative of a one-in-ten weather year based on population-weighted cooling degree hours. That year had higher overall energy use in Climate Zones 2 and 3, and lower energy use in Zone 4 than for the average year. As a result, the demand response benefits increase for Zones 2 and 3 and decrease in Zone 4. In total, the benefits for Scenario 4 increase due to the 1-in-10 year weather analysis. Scenario 17, however, only includes the population of Zone 4. Due to the lower energy usage and cooling degree hours in Zone 4 during 1-in-10 year weather, the demand response benefits are decreased for Scenario 17 from the average weather analysis. The results are shown in Table C-13 below. Supporting data are provided in Tables C-14 and C-15 below.

Table C-13
1-in-10 Year Weather Adjustment Results to Total Demand Response Benefits
PV $2004, in Millions

Scenario	Average Weather Analysis	1-in-10 Weather Analysis	Difference
4	$366.7	$403.5	$36.8
17	$42.9	$35.0	($7.9)

Table C-14
Cooling Degree Hours by Zone and Period for 1-in-10 Year

Climate Zone	CPP Day		Non-CPP Day		Average Summer Day	
	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak
2	13.01	3.39	3.50	0.52	3.98	0.67
3	22.82	7.23	9.94	1.63	10.59	1.95
4	23.41	10.31	15.93	5.47	16.50	5.80

Table C-15 1-in-10 Year Energy Use by Class and SCE Climate Zone (kWh/hr)								
Rate Group	**SPP Climate**	**CPP Day**		**Non-CPP Week Day**		**Summer Week Day**		**Weekend/ Holiday**
	Zone	**Peak**	**Off Peak**	**Peak**	**Off Peak**	**Peak**	**Off Peak**	
Residential	**2**	0.92	0.68	.67	0.56	.70	.57	0.60
	3	1.90	1.06	1.12	0.73	1.19	.76	0.84
	4	1.48	0.87	1.05	0.67	1.09	.69	0.80
GS-1	**All**	2.47	1.33	2.18	1.20	2.22	1.22	1.03
GS-2 < 200 kW	**All**	27.19	17.86	25.09	16.57	25.36	16.73	14.15

3. Impact on Total Annual Energy Use

The November 24, 2004 Ruling directed SCE to answer the following question – "In other words, does the tariff structure assumed result in overall reduced energy usage (conservation impact), shift of load (no overall impact), or increased energy usage?"[23]

To perform this analysis, we used the results from the CRA all-summer PRISM model and results from the CRA all-winter PRISM model, as adjusted for SCE territory and assumed responsiveness. As described in the summer analysis, Non-CPP day CPP-F results were used as a proxy for TOU rates. We provide the results of this analysis for a single year after full deployment in 2012. The results of the analysis provided in the table below shows that there would be an increase in total energy use in each scenario. To put this increase in perspective, for Scenario 4, the increase would be about 0.01 percent of total SCE customer consumption.

[23] Assigned Commissioner and Administrative Law Judge's Ruling Calling for a Technical Conference to Begin Development of a Reference Design, Delaying Filing Date of Utility Advanced Metering Infrastructure Applications, and Directing the Filing of Rate Design Proposals for Large Customers, November 24, 2004, R.02-06-001, p. 4.

Table C-16 Impact on Annual Energy Use (kWh/yr) by Tariff and by Class for 2010				
	Scenario 4		Scenario 17	
	CPP-F	TOU	CPP-F	TOU
Residential	11,187,500	-990,486	3,859,873	254,770
GS-1 (<200kW)	-245,701	-48,655	143,782	11,053
GS-2 (<200kW)	-687,367	-141,880	381,490	29,071
Total	10,254,432	-1,181,020	4,385,144	294,894
Grand Total	**9,073,412**		**4,680,038**	

4. Cost-Effectiveness of Enabling Technology Combined with CPP Rates

In our preliminary business case analyses, we included Scenario 7 which provided the costs and benefits of demand response plus reliability case using a default CPP enrollment plus enabling technology. Our approach in Scenario 7 was to deploy our Advanced Load Control (ALC) smart thermostat technology to a portion of customers not on CPP rates. We used this approach because there was a lack of representative data from the 2003 SPP on the cost and load impact results of customers on CPP rates with enabling technology. We also did not know how many customers would adopt enabling technologies without incentive payments. While those studies provided a reliability component of demand response benefits, the ALC deployment is considered as a decision separate from AMI because we have included ALC is in our business-as-usual case (*see* Appendix G).

For this business case analysis, we used the SPP results for Summer 2004 that provide sample data on two key issues not provided in the Summer 2003 results. With those results, we were able to determine that a scenario assuming CPP coupled with an offering of enabling technology was not more cost effective than our Scenario 4. This analysis is explained below.

The Summer 2004 SPP study provided data on two issues with respect to enabling technologies. First, the study provided an estimate of customer acceptance of enabling technology combined with a CPP rate. A sample of customers from Track A in the SPP was offered a choice whether or not to accept enabling technology, free of charge. About

30 percent of the customers accepted the installation of a Smart Thermostat. No incentives were paid to the customer for allowing the utility to control the thermostat. The second key data provided by the SPP was the demand response of customers in Track A with enabling technology. The demand reduction impact of enabling technology is found in the 2004 data.

We used the assumptions for Scenario 4 where 80 percent of residential customers default to the CPP-F rate. To determine the penetration of enabling technology in this scenario, we applied the 30 percent acceptance rate for enabling technology to the percent of customers who would opt-in to the CPP-F rate. As discussed above, that percentage is 16.8 of residential customers. This yields about five percent of customers on CPP-F rates with the enabling technology and 75 percent of customers on CPP-F without enabling technology. For the cost of enabling technology, we assumed the costs for our ALC smart thermostat (smart thermostat $95 and installation $98.25/unit). Finally, we relied on the SPP Summer 2004 results for Track A customers with enabling technology as the expected demand reduction for that group of customers. The overall result of the scenario with enabling technology was about $36 million in net present value worse than Scenario 4. This is not entirely surprising because the demand response benefit of enabling technology relies on the same load reduction source as the CPP rate at peak. The benefit of the net increase in load reduction derived from enabling technology does not overcome the added cost of the smart thermostat plus installation.

Appendix D

Avoided Procurement Cost Value Assumptions

APPENDIX D

AVOIDED COST VALUE ASSUMPTIONS

A. Summary of CPP Analysis Methodology

This Appendix describes our approach in evaluating the economic generation benefits of demand reductions induced by Critical Peak Pricing (CPP) in the final AMI business case analysis. The approach uses avoided cost principles (marginal energy and capacity) as the value proxy for generation benefits and also incorporates "value adjustments" (both positive and negative) to account for reserve margin benefits, certain operational restrictions attributed to CPP, and uncertainties in market forecasts for supply availability and load. This methodology was used in combination with the Commission-assigned estimates of avoided capacity and energy values to analyze the economic benefits of demand reductions resulting from CPP. We believe the end result is a more accurate and mathematically-sound assessment of the economic value of demand reductions caused by CPP to our customers.

B. An Avoided Cost Approach Was Used To Value The Generation Benefits of CPP

Characteristically, demand response programs derive most (~90 percent or more) of their generation-related value from avoided capacity costs rather than avoided energy costs.[24] Limited-event demand response programs or tariffs, such as CPP, are designed to help mitigate peak load requirements for short durations, not unlike a peaking resource. Such limited-event resources provide opportunities to displace higher-cost energy only when triggered. However, CPP can displace the need for a capacity resource (*i.e.*, combustion turbine) during those periods, which can result in significantly more value than the potential for energy displacement.

For the two required business case scenarios, we assigned a capacity value of $85 per kW-yr, an energy value of $63 per MWh, and a congestion avoidance value of $7 per MWh

[24] Other potential benefits may exist which are not discussed here, such as O&M savings.

consistent with the July 21, 2004 Ruling.[25] Both the energy and capacity values are assumed to be "at the generator" level and levelized over a 15-year period assuming a utility discount rate.

The Commission has a long-standing policy of using a combustion turbine (CT or peaker) proxy method for estimating the marginal value of capacity and a system marginal energy cost for estimating the marginal value of energy.[26] The Commission's view of $85 per kW-yr is nearly the same as our view of marginal capacity value, which is based on the real economic carrying charge methodology[27] of a CT. Similarly, the Commission's view of $70 per MWh[28] is nearly the same as our marginal energy cost estimates for the highest peak periods when CPP would be triggered. This estimate is based on our adopted 2004 Long-Term Procurement Plan (LTPP),[29] with updated assumptions for gas prices, loads and resources to better reflect more recent forecasts.

1. Crediting Capacity Value to CPP

Capacity is generally defined as the right to call on the production of energy, and is analogous to financial call options. It is important to note that capacity only has value if it can be called upon for energy or defers the need for energy. This is a fundamental principle in both electricity and financial markets. In financial markets, a call option's value is derived

[25] Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure (Ruling), July 21, 2004, Appendix B.

[26] For economic valuation purposes, the value of capacity is never higher than the cost of a CT since any greater capital investment would be justified by lower energy costs. This concept is known as Energy Related Capital Costs ("ERCC").

[27] Also referred to as the rental value or deferral value method. We will be updating our view of marginal capacity value in Phase 2 of our General Rate Case (GRC) A.04-12-014 to be submitted in May 2005, consistent with the real economic carrying charge methodology, as we have done in previous GRC filings.

[28] $63 per MWh energy + $7 per MWh congestion charges.

[29] The LTPP was found reasonable and adopted by the Commission on December 16, 2004 in Decision (D.) 04-12-048, subject to modifications that do not significantly affect the need, timing or cost effectiveness analysis of CPP. The baseline assumptions of the LTPP were designed around the overall intent and "loading order" of the joint agency Energy Action Plan, including significant increases in cost effective energy efficiency and demand response programs and meeting the 20 percent Renewable Portfolio Standard by 2010.

from the option holder's right to exercise the option. In electricity markets, the hourly energy requirement of a load serving entity (LSE) is based on its ability to call upon firm capacity resources, whether contracted or directly owned. These capacity resources are in effect "call options" in which the LSE decides from hour to hour whether to exercise these capacity resources for energy. If a particular capacity resource is unable to provide energy when the call option on the energy is exercised,[30] then the value of the resource's capacity to the LSE is zero for the period it was unavailable. This is a common performance-based attribute of how capacity payments are made by LSEs to generation owners.

Demand response programs, generally, cannot be called upon more often than a specified number of strikes (calls) on an annual and daily basis. In the case of CPP modeled in our analysis, this tariff is limited to twelve calls per summer period, and each call cannot exceed a continuous five hours in duration. CPP can effectively be exercised no more than sixty hours per year (12 events per year × 5 hours per event). In contrast to a combustion turbine, which can be called upon up to 8,760 hours in a year, the CPP program is a much less available resource and therefore has less capacity value.[31] However, having lower capacity value benefits does not mean a program is not cost effective; the investment costs of a demand-response program may be lower than that of a CT (on a per kW basis), making the demand-response program more cost-effective by comparison.[32] In order to properly evaluate any difference in capacity value, we must understand the way in which capacity value is allocated across time.

[30] Possibly due to an outage, other physical limitation such as exceeding environmental or startup limits.

[31] This attribute is also true of limited energy resources such as wind generation.

[32] In the case of AMI, where the decision on making a long-term investment in costly metering infrastructure hinges on demand response benefits, the relative value of CPP (including metering infrastructure costs) as a resource compared to other resources is paramount.

2. Time Differentiating Capacity Value

Both marginal energy and capacity values are time differentiated. Energy costs vary according to daily gas prices and hourly system incremental heat rates. Gas prices and heat rates are typically higher during peak demand periods, therefore differentiating energy value across time. Likewise, capacity value varies according to need and the relative risk of low reserve margin events. Periods of supply shortages during system contingencies (unanticipated or anticipated) tend to increase the value of capacity, therefore differentiating capacity value across time.

The marginal capacity value provided by the Commission ($85 per kW-yr) is an annualized value and not yet differentiated by time. Thus, we have "spread" or allocated the annual marginal capacity value using relative loss of load probability (LOLP) values to indicate time differentiated values based on peak period usage.[33] LOLP is a measure of system reliability that indicates the ability (or inability) to deliver energy to the load. A more detailed description is provided in the next section.

a) Loss of Load Probability

There is always some probability, however small, that the electricity system will be unable to serve demand. The risk of a generation shortage can be reduced by over supplying generation, but over investment and high operating costs would significantly increase customer bills. Determining the optimum supply and demand balance requires the study of expected system operations using a probabilistic risk assessment approach. Analysis of a system's LOLP is an appropriate risk assessment approach – it is a measure of system reliability that indicates the ability (or inability) to deliver energy to the load.

The LOLP metric provides a method for allocating annualized capacity value across time-of-use periods in proportion to when the loss of load is likely to occur.[34] For

[33] This approach is a standard utility practice and has been used in prior SCE GRC proceedings.

[34] The purpose of this LOLP analysis is not to forecast the precise timing of future low-reserve margin events, nor is it to forecast the absolute magnitude of any single loss-of-load event. Rather, it is intended to be a relative distribution of risk used to allocate capacity value across time.

example, if the LOLP is greatest in the summer period primarily due to load conditions, particularly during the on-peak, then most of the value we would attribute to capacity will be assigned to those periods. On the other hand, if the probability for loss-of-load is essentially zero during winter off-peak periods, we would assign very little capacity value at those times. LOLP makes it possible to evaluate the relative reliability contribution of different resources across a range of time-of-use periods.

We used Henwood's MarketSym model and the "Medium Load Plan Scenario" from our adopted 2004 LTPP[35] as the basis to calculate a probabilistic estimate of the fraction of time that the SCE system is unable to meet demand. Our analysis employed a Monte Carlo approach by way of two-factor mean reversion sampling of loads and resources. The analysis performed 250 simulations of the entire Western Electricity Coordinating Council (WECC), each unique with regard to hourly supply and demand. From the Monte Carlo analysis, we were able to extract hourly resource availability and loads from each of the 250 simulations. An LOLP event occurs in hour *h* when the load (*L*) exceeds available resources (*R*).

$$L_h - R_h > 0$$

For each simulation, the load in a particular hour can be compared to each of the 250 Monte Carlo outcomes of resource availability in that same hour. In other words, the load in hour *h* is assumed to have the same likelihood of occurring in any of the 250 resource outcomes in hour *h*. The same is true from another viewpoint: the resource availability in hour *h* is assumed to have the same likelihood of occurring in any of the 250 load outcomes in hour *h*. Effectively, this approach yields 250 × 250 or 62,500 possible combinations of load and resources in hour *h*. The above equation can be modified to illustrate this method.

$$L_{h,i} - R_{h,j} > 0$$

[35] *See* footnote 6, *supra.*

Where i and j are from the respective simulations for load and resources. The range of loads and resources is determined by stochastic parameters tied to historical performance.

Each load and resource combination is given equal probability of occurring assuming short-term variations in loads (*i.e.*, weather) and available resources (*i.e.*, forced outages) are purely random. Combinations in which available resources are unable to meet the load (hence, loss-of-load) contribute to the LOLP for that hour. For example, if 125 out of the 62,500 combinations resulted in loads exceeding available resources, then the LOLP for that hour is 0.2 percent (125 divided by 62,500), or a probability of 1 in 500.

The hourly LOLPs, or stochastic LOLPs, are normalized over all hours of the year such that the sum of the normalized LOLPs equals 1. This effectively creates a relative relationship of the hourly LOLP across time.

The stochastic LOLP approach takes into account as much uncertainty as can reasonably be captured within the limitations of the model. These are the same uncertainties facing today's system operators (load forecast, supply availability, and hydro conditions). We believe this approach provides a reasonable representation of estimating the relative risk of not serving the load in any given hour, realizing that not all of the market's inefficiencies can be captured in any single model.

3. Incorporating Necessary Value Adjustments to The Avoided Cost Approach

Generally, the capacity value (*Vc*) of a supply- or demand-side resource is equal to the expected deliverable capacity (*EDC*) of that resource multiplied by the avoided cost of capacity (*AC*).

$$Vc = EDC \times AC$$

For the purposes of analyzing CPP, the *AC* (measured in $/kW-yr) is based on the July 21, 2004 Ruling's value of $85 per kW-yr. The *EDC* is the kW quantity expected to be reliably available and deliverable to the load.[36] For example, if a supply-side resource has a nameplate rating of 100 MW, but after considering expected delivery limitations due to congestion, losses and the environment,[37] it may actually only deliver 80 MW of electricity to the grid. It would be inappropriate to give 100 MW "capacity credit" to this resource if only 80 percent of it is expected to be deliverable. The same is true for demand-response programs, such as CPP, where customer participation based on historical response results will likely reduce the program's nominal rating to a more realistic level.

However, the above equation does not consider certain attributes associated with a demand response program that will affect the value of capacity. The equation will require an adjustment factor to account for the reduced need to procure planning reserves (adding value), and two adjustment factors to account for operational restrictions (subtracting value), all of which are discussed below.

Unlike a supply-side resource, a demand response program reduces an LSE's resource requirement. In effect, this reduces the need to procure additional reserves to meet the load.[38] Therefore, the value of a demand response program should include the value of capacity associated with procuring for a planning reserve margin (*PRM*) requirement.[39]

$$Vc = EDC \times AC \times (1 + PRM)$$

In the above equation, it is important to make the distinction between capacity that can be used to serve the load and capacity that meets resource adequacy requirements. In other words, only 100 percent of the *EDC* can actually be used to serve the load, but 115 percent of the *EDC* can be applied to meet resource adequacy requirements. This distinction

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[36] Both the *AC* and *EDC* values need to be at the same delivery level, *i.e.*, at generator, at ISO-interface, or at the customer level. For the purposes of this analysis, the *Vc* inputs are evaluated at the generator level.

[37] For example, opacity limitations.

[38] For every MW of expected load reduction due to demand-side management, 1.15 MW of capacity procurement is avoided, assuming a 15% planning reserve margin (*PRM*) as directed by the Commission in D.04-10-035, Conclusions of Law No. 4.

[39] *Id.*

is necessary when we later consider the operation limitations of CPP, which will only apply to the *EDC* portion that is dispatchable. Thus, the equation can be algebraically expanded to make this distinction:

$$Vc = (EDC \times AC) + (EDC \times AC \times PRM)$$

The CPP program is a limited energy resource, meaning, it can only be exercised for a limited number of hours per year. Specifically, CPP can be called 12 times a year for five hours each, and only during the summer months. As discussed earlier, capacity only has value if it can be called upon for energy or defers the need for energy. The dispatch limitations of CPP will reduce its value of capacity relative to a CT proxy, which is available year-round. To account for this reduction in value, the prior equation should apply an adjustment factor (*A*) to the dispatchable *EDC* portion:

$$Vc = (A \times EDC \times AC) + (EDC \times AC \times PRM)$$

Where the *A*-factor is less than or equal to 1.

The avoided cost of capacity (*AC*) assigned by the Commission is assumed to be based on a CT proxy, which is a day-of call option[40] for power. Some demand response programs, such as CPP, are designed to be (one) day-ahead options. Generally speaking, a day-of call option has more intrinsic value than a day-ahead call option by virtue of the former having greater flexibility in time of need. To credit the full value of capacity as defined by a CT proxy to a day-ahead program would not be a fair evaluation and will overstate its value. Therefore, the equation should be modified to reflect this adjustment in capacity value with a factor (*B*).

$$Vc = (A \times EDC \times AC \times AC) + (EDC \times AC \times PRM)$$

Where the *B*-factor is less than or equal to 1. For a demand response program that can be dispatched day-of, the *B*-factor by default equals 1.

Finally, the equation can be algebraically modified in its final form as:

[40] The capacity from a CT proxy can be used for energy with one hour notice.

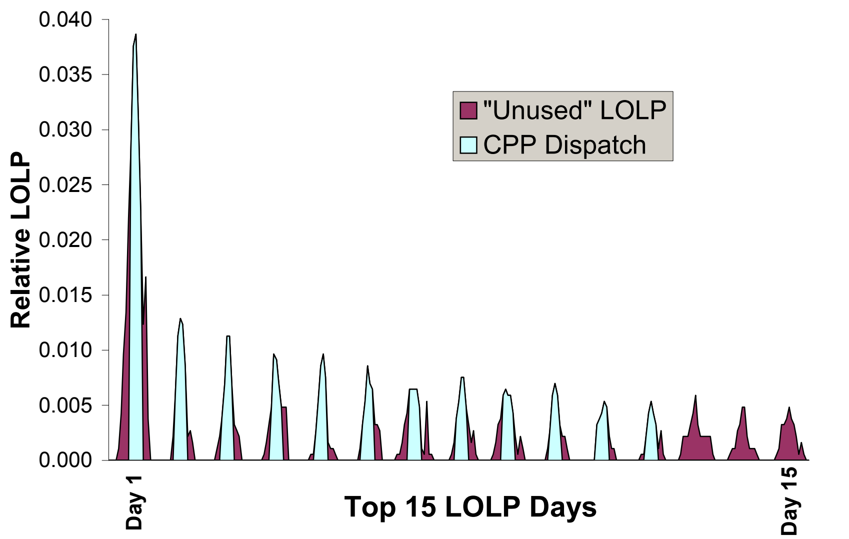
$$Vc = EDC \times AC \times (A \times B + PRM)$$

a) The *A*-Factor

The *A*-factor is determined by simulating an optimal dispatch of the CPP program against an LOLP forecast, and calculating the percentage of time the program is able to "displace" LOLP events, subject to the program's dispatch limitations. As discussed earlier, the LOLP forecast is a method of allocating capacity value across time. To the extent the CPP program can be available during times of need (as defined by the LOLP forecast), it will be credited capacity value during those times. In the optimal dispatch simulation, the CPP program is assumed to be called upon as often as allowed during periods of greatest LOLP. The following figure illustrates the highest LOLP hours over the top 15 days. Each daily LOLP extends for several hours within the day, ranging between 11 AM and 9 PM. Although the CPP program is optimally dispatched, the five-hour window is not enough to capture all LOLP hours in each day. Furthermore, since the CPP program is limited to 12 calls per year, it does not capture LOLP events beyond the 12th day.[41]

[41] Ninety-five percent of the total LOLP occurs over the span of 29 days.

Figure D-2



This analysis results in an *A*-factor of 50.2 percent. The *A*-factor can be increased in three ways: 1) increase the number of allowable events per year beyond twelve; 2) extend the duration of each event to more than five hours; or 3) allow the program to be called during non-summer months.

b) The *B*-Factor

The *B*-factor is based on the difference in value between a day-ahead and a day-of call option for power. A CT is essentially a day-of call option with a strike price equal to the variable operating cost of a CT proxy. The CT proxy value should be adjusted downward for demand response programs that are callable on a day-ahead basis. The CPP program, for instance, is a day-ahead call option resource. For a demand response program that can be dispatched on a day-of basis, the *B*-factor equals 1 by default.[42]

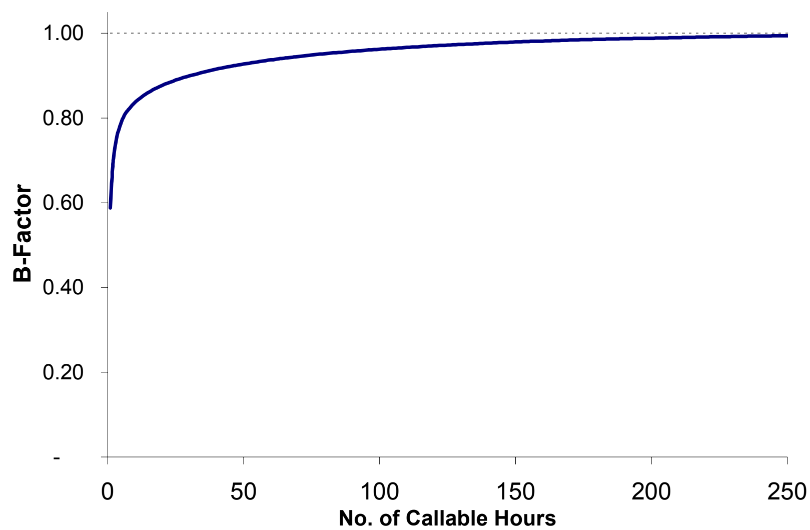
One approximate method to capture the difference in value between a day-ahead and a day-of program is to compare the value of a day-ahead and day-of call option

[42] If the notification time for a day-of CPP program is greater than the time between dispatching a CT and receiving energy, then the value of the *B*-factor is less than 1.

resulting from a Black-Scholes option model.[43] The Black-Scholes model is a standard tool for valuing energy options, but can be used to estimate the relative "payoff" of demand response resource options with differing times to expiration (time horizon). Inputs to the model are the forward view of LOLP, day-ahead and day-of volatility of LOLP, and time to expire. The output of the model is a relative value of each call option. Comparing model outputs for day-ahead volatility inputs versus day-of volatility inputs provides a relationship that can be used to approximate the relative value of a day-ahead versus a day-of demand response program.

For a day-ahead demand response program,[44] the *B*-factor is represented in the Figure below.

Figure D-3



The value of a day-ahead call option approaches the same value of a day-of call option if the day-ahead option has sufficient callable events. A demand response program that is dispatchable for 300+ hours will likely capture all of the LOLP events in a year, regardless of whether the program has a day-ahead or day-of dispatch requirement.

43 John C. Hull, 3rd Edition, p. 393.

44 The *B*-factor only applies to demand response programs with a zero strike price.

In the case of CPP, which is dispatchable up to 60 hours per year, the *B*-factor is 0.937.

c) CPP Capacity Value Results

Given the following:

$$Vc = EDC \times AC \times (A \times B + PRM)$$
$$where$$
$$A = 0.502$$
$$B = 0.937$$
$$PRM = 0.15$$

$$Vc = EDC \times AC \times 0.62$$

Or, the value of capacity (*Vc*) credited to CPP is 62 percent of the full deferral value of a CT proxy. Based on this analysis, the value of capacity at the generator from the CPP program is \$52.7/kW-yr, as shown below:

$$Vc = EDC \times \$85/\text{kW-yr} \times 0.62$$

$$Vc = EDC \times \$52.7/\text{kW-yr}$$

To compute the benefit of the CPP program at the customer level, a distribution loss factor must be applied to the avoided capacity benefit at the generator.

Appendix E

Uncertainty/Monte Carlo Analysis Assumptions

APPENDIX E

UNCERTAINTY/MONTE CARLO ANALYSIS ASSUMPTIONS

A. Monte Carlo Analysis of Demand Response Benefits

Consistent with the July 21, 2004 and November 24, 2004 Rulings, we applied a Monte Carlo simulation approach to the demand response benefit calculation for each scenario. For the opt-out enrollment scenarios, we distinguish customer response between “willing enrollments” and “default enrollments,” as explained in Appendix C. For the Monte Carlo analysis, we varied the customer behavior characteristic of default enrollments from a mean of 50 percent of the load impact of the SPP experiment to 33 percent on the low side and 67 percent on the high side.

In addition, we applied a derated value of demand response (CPP-F tariff) resources, as described in Appendix C. For this Monte Carlo analysis, we assumed a distribution of plus or minus 10 percent around our estimated value of $52.70 kW-yr.

We employed a standard software application, Crystal Ball, to run a Monte Carlo simulation across the range of the above variables. Our alternative results for the DR-1 capacity and energy benefit for Scenario 4 are shown in Table E-1 below.

Table E-1
Monte Carlo Analysis of Demand Response Benefits (DR1 Only)
(PV $2004, in Millions)

	Scenario 4		Scenario 17	
	W/O losses	Including Avoided Losses	W/O losses	Including Avoided Losses
SCE Low	$181	$196	$21	$23
SCE High	$211	$229	$24	$26
SCE Expected Value	$193	$209	$23	$25

Appendix F

Financial Assumptions

APPENDIX F

FINANCIAL ASSUMPTIONS

Our key financial assumptions to develop the cost and benefit information used in our business case analysis for Scenarios 4 and 17 are discussed below.

A. Labor Costs

All of our labor estimates are based on annualized Full Time Equivalent (FTE) employee requirements. Non-represented labor costs were determined by the SCE Market Reference Point for specific job titles. Represented labor costs were determined by our current labor contract for the appropriate job title. Pensions and benefits costs for health care, pension, and benefit plans were determined using marginal costs and escalation rates that are consistent with SCE's 2006 General Rate Case. Installation and meter-handling labor is allocated sixty percent to installation of new meters, and forty percent to removal of old meters. Where required, severance costs were estimated by our Human Resources Department using existing severance plans and policies. Severance is contemplated for certain positions under the full deployment scenario, while some positions will be reduced solely through attrition. Where additional facilities are required for added workers, incremental facility costs for field personnel, Customer Communications, and Billing staff were estimated using market lease rates for the specific required facilities.

B. Capital Costs

Capital costs for AMI meters include meters, installation labor, direct supervisory costs, and related vehicle, material, and supply costs. Tax depreciation for cash flow purposes is based on relevant Internal Revenue Service rules. Capital costs of replacing any devices (*i.e.,* servers, computers, meter batteries), whose useful lives expire between 2006 and 2020 are included in the analysis. Although significant capital replacements for meters, communications equipment and IT hardware would be scheduled to occur in 2021, costs for these replacements were excluded from our analysis.[45] The estimated net salvage value of $1.00 per meter has been credited against removal expense. Unrecovered capital costs at the end of 2021 are not included in the revised preliminary analysis, but would be recovered over future periods.[46]

C. Taxes

For cash flow purposes, we used tax rates of 35 percent for federal and 8.84 percent for state. Tax benefits from early write-off of the removed meters are included in the cash flow and revenue requirement analysis.

D. Cost of External Financing

The July 21, 2004 Ruling requires the utilities to evaluate various financing options for the large capital expenditure anticipated for a full deployment of AMI. Specifically, the July 21, 2004 Ruling required the utilities to evaluate both an internal financing/implementation approach as well as an outsourcing approach in which AMI acquisition, installation, and O&M would be obtained under contractual arrangements with third-party providers.[47]

Any large contractual obligation on the part of SCE has a detrimental impact on SCE's credit rating. For any outsourcing arrangement where we are the counterparty, such as contracting to pay a third-party for 15 years for meter installation/ownership or for meter O&M, rating agencies equate the capital lease with a debt instrument. Thus, in addition to cost of the cash payments to the third-party, capital leases appear on our balance sheet and must be offset by adding equity to the capital structure. Importantly, as was discussed in the outsourcing business case scenarios contained in our revised preliminary business case analysis submitted on January 12, 2005, none of the potential AMI outsource providers

[45] *See* "Uncertainty and Risk Analysis" in Sections IV and V of Volume 3.

[46] Unrecovered capital costs in 2021 were estimated to be approximately $19 million and $190 million for the partial and full deployment scenarios, respectively.

[47] *See* July 21, 2004 Ruling, Attachment A, pp. 4, 8.

demonstrated the ability to provide superior financing terms above our own, notwithstanding the capital lease issue.

E. Net Present Value Analysis and Assumptions

As detailed in Volume 3, all operating costs and benefits were estimated in 2004 dollars, and then escalated to nominal (year-incurred) dollars. Annual nominal cash flows were then summarized and discounted back to 2004 dollars using Excel's "NPV" function, with a 10.5 percent discount rate. All references in these volumes to "2004 NPV" or "2004 Present Value" use this approach. Demand Response benefits were analyzed using the levelized capacity and energy values specified in the July 21, 2004 Ruling.

We present our NPV analysis under two approaches. Under the first approach, we calculated the NPV of each scenario using a standard discounted cash flow approach. Each year's nominal costs and benefits were summarized along with their tax impacts,[48] to produce an after-tax cash flow NPV.

The revenue requirement analysis utilized the same nominal costs and benefits, but used regulatory (or "book") depreciable lives for capital assets and included the carrying costs of new capital investments. It also incorporated the rate impact of the accelerated recovery of the existing meters, which would be removed in an AMI deployment.

The after-tax cash flow analysis demonstrates that, on a financial basis, projects with negative NPVs are a poor use of capital. The revenue requirement analysis demonstrates whether a project will have a beneficial or negative impact on customer rates.

To calculate the annualized or monthly revenue requirement impact, the annual revenue requirements for each scenario were discounted back to a 2004 present value and were then levelized over the 2006 – 2021 analysis period.

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

F. Revenue Requirement Analysis and Assumptions

Revenue requirement impacts, including both the operating expenses and capital costs associated with AMI implementation, were assessed. We estimated net AMI-related revenue requirement impacts for the two scenarios for years 2006 through 2021. These estimates, which are detailed in Appendix K, were determined by subtracting expected revenue requirement reductions from estimated AMI-related revenue requirement. Revenue requirement reductions include cost savings from Customer Service-related O&M reductions, existing meter revenue requirements reductions and procurement cost reductions. AMI-related revenue requirement includes: 1) anticipated O&M expenses and capital costs associated with expected rate base amounts for new AMI-related meters and related infrastructure; and 2) stranded costs associated with the undepreciated balance of existing or replaced meters, which we propose to amortize over the five-year new meter deployment period. We estimate for Scenario 4, that the total project NPV revenue requirement increase would be $952 million, or $125 million annually. For Scenario 17, we estimate that the total project NPV revenue requirement increase would be $130 million, or $17 million annually. These results are discussed in detail in Volume 3. These revenue requirement impacts were assessed for business case analysis purposes only.

G. Treatment of Costs Not Clearly Anticipated by the July Ruling

1. Pre-2006 Start-up Costs

The July Ruling mandates a "2006 to 2021 analysis period,"[49] but in order to meet the five-year deployment target, some costs would have to be spent in 2005 to prepare for a 2006 rollout. These pre-2006 costs have been included in the business case scenarios as 2006 costs.

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

2. Early Retirement of Meters

To implement AMI, all existing meters that do not meet the communication and interval data capabilities required by the July Ruling would have to be replaced, even though those meters that still have much of their useful life left. As of June 2004, we have approximately $318 million in undepreciated meter capital, after adjusting for the small percentage of out-of-scope meters in Scenario 4. Accounting rules require SCE to charge the undepreciated balance of the retired meters, along with the cost of their removal (net of salvage value realized) against accumulated depreciation. This total is estimated to be approximately $631 million for Scenario 4. We have incorporated this cost into the business case, as cost code "MS-9 Salvage/Disposal process for removed meters." These costs will need to be recovered contemporaneously with the system installation through an appropriate cost recovery mechanism.

Appendix G

Business As Usual Case

APPENDIX G

BUSINESS AS USUAL CASE

A. Overarching Approach

The Business As Usual case, as described in the July 21, 2004 Ruling, is to serve as the "base case," or reference point from which to compare the relative costs and benefits of the full and partial AMI deployment scenarios. This case serves three primary purposes: (1) to identify those significant metering and communications investments made that can be leveraged by AMI, and therefore should not be included in the deployment scenarios as new incremental cost; (2) to identify those investments that can be avoided if AMI is deployed; and (3) to identify those investments (*e.g.*, ALC) whose load reduction benefits will be replaced by implementing AMI. For SCE's analysis, we define "Business As Usual" to mean no changes to our metering infrastructure or demand response programs beyond those currently in place or anticipated in the normal course of doing business under existing regulatory standards relating to these matters. Unlike the two AMI deployment scenarios in this analysis, the Business As Usual case is based on actual costs as recorded, and forecast in our 2006 General Rate Case (GRC) proceeding.[50] For the July 21, 2004 Ruling's required analysis period, beyond the time period forecasted in the GRC (*i.e.,* 2009 through 2021), we trended costs based on our experience and judgment. By defining our Business As Usual base case in this manner, we are able to determine all incremental costs that would be incurred solely as a result of AMI deployment, as well as identify which base case costs would be eliminated by AMI.

Although we expect that technology improvements over the next 16 years will likely change today's cost and benefit structure, to facilitate our analysis, our base case assumes that the current operating environment and cost and benefit structure will remain static over

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

the 16-year study period.[51] We will make modifications or adjustments to the base case in order to avoid double counting of costs or benefits where appropriate. For example, full deployment of AMI meters would eliminate the cost of meter purchases that otherwise may occur under the base case. These modifications are described in more detail in the Full and Partial "Business Case Analysis" (Scenarios 4 and 17) in Sections IV and V of Volume 3.

Table G-3 shows the recent history and our forecast of "business as usual" metering capital and O&M expenditures.

Table G-3
Metering O&M and Capital Expenditures
Business As Usual Case ($ Million)

	Recorded					Forecast				
	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Metering O&M	$6.3	$5.4	$4.6	$5.1	$6.2	$7.2	$7.2	$7.4	$7.5	$7.7
Metering Capital	$12.8	$18.8	$12.6	$16.1	$17.6	$20.3	$21.9	$19.2	$19.0	$20.1

B. Existing Advanced Metering and Communications Infrastructure

In the normal course of doing business, we assess the potential for improving operational efficiency and have already implemented advanced metering and communications technologies as previously mandated, as well as automated meter reading (AMR) in those areas where it appears to be operationally efficient and economically beneficial to ratepayers to do so.

[51] Although unlikely, it is necessary to assume costs and benefits will remain static for our purpose here in order to establish the necessary baseline against which the deployment scenarios can be compared.

1. Real Time Energy Metering (RTEM)

We currently have approximately 13,000 RTEM installations which measure 15-minute interval usage data for customers with monthly demands of 200 kW and greater.[52] We also have approximately 700 RTEM units in place for our residential and small commercial customers who participated in the SPP. In addition, we have roughly 10,000 Dynamic Load Profile meters which are used to provide load data for system planning and California Independent System Operator (CAISO) settlement purposes. Data is collected daily from these accounts via paging, telephone, and radio-frequency (RF) communications. Our automatic data collection system makes this data available to our largest customers via the Internet. This data is also used in the monthly billing for our largest accounts and thus, we no longer routinely read these meters manually. Full scale implementation of AMI would essentially eliminate the need for the Dynamic Load Profile metering, given that these meters would be replaced with AMI meters.

2. Automated Meter Reading

We have been a pioneer in mass implementation of AMR, with over 500,000 meters that are currently read using AMR technology. Approximately 360,000 of these meters are installed in our highest cost-to-read routes and are being read by a vendor from a "drive-by" van on a monthly basis. The remaining AMR meters are also high-cost-to-read meters (typically installed because of access problems or meter reader safety issues), scattered throughout our service territory. These meters are read monthly by the meter readers as they "walk-by" these locations on their routine monthly routes. All of our AMR systems utilize meters equipped with encoder/receiver/transmitters (ERTs) which could (theoretically) be paged hourly via a two-way radio network. However, because we are

[52] Pursuant to the December 8, 2004 Assigned Commissioner and Administrative Law Judge's Ruling Directing the Filing of Rate Design Proposals for Large Customers, SCE is moving forward with installations of RTEM meters on the approximately 2,000 customers who do not already have an RTEM. These costs have not been included in this analysis because they are part of the Business As Usual base case.

currently utilizing these systems only for monthly billing purposes, the walk-by, and drive-by data retrieval method is more cost effective.

The AMR program is concentrated in those parts of our service territory where it is most cost effective. We continue to add approximately 20,000 new ERT meters annually as access or safety related problems arise and as we continue to monitor the cost/effectiveness of our existing meter reading routes. Thus, our Business As Usual case includes our estimate of future on-going costs of maintaining AMR and communications technology in today's operating environment.

Under Scenario 4, we have assumed that the entire AMR infrastructure is replaced by AMI. This replacement, on the July 21, 2004 Ruling's mandated deployment schedule, would leave us with an unfulfilled contractual obligation with a vendor for AMR meter reading through 2011. Although these AMR costs would be stranded under AMI deployment, they are reflected in current rates. Thus, we did not make any adjustment to remove these costs from either the full or partial deployment scenarios so that these costs would continue to be recovered. There are no incremental operational savings prior to 2011 that result from re-automating existing AMR meters. To partially mitigate the cost of this fixed commitment, we have assumed the conversion of the AMR routes to AMI would take place late in the AMI implementation schedule, thus obtaining maximum value from the current contract. Avoided cost savings after 2011 would be minimal, since the meters would still need to be read monthly by a vendor or by an SCE meter reader.

3. Advanced Load Control

Air Conditioning Cycling (ACC) systems can and do function effectively, independent of the proposed AMI infrastructure. This is the case with over 124,000 currently-active ACC participants via SCE's existing RF communication systems. In SCE's Long-Term Procurement Plan (LTPP) filed in R.04-04-003, we submitted our proposal to expand and enhance our residential load control program to increase the demand response this program delivers.

Our proposed Advanced Load Control (ALC) Program would result in 500,000 customers participating in load control and providing an estimated peak demand benefit of 700MW. Under our ALC proposal, the cost of ALC devices was estimated to be $138 per residential unit and $130 per unit for installation. Under the AMI deployment scenarios, we assumed that the ALC equipment and installation could be combined with the AMI meter deployment. For the combined deployment, we assumed that the ALC device would be about $95 per residential unit and installation would be $100 per unit.

4. Outage Management System (OMS) and Transformer Load Management (TLM)

We have already invested in developing automated systems to assist us in detecting power outages (through the OMS) and managing load on our transformers (through the TLM system). As described in SCE's 2006 GRC, we continue to improve automation and data communications for its substation operations with Intelligent Electronic Devices (IEDs) that communicate through a Local Area Network to our Supervisory Control and Data Acquisition (SCADA) System.[53] The modern protection and control equipment we are using provides remote, self monitoring control of substation functions, and identifies potential problems to avoid reliability events to which we must respond quickly. Among the many types of automation and sophisticated electronic equipment that we use in our substations and operations network are satellite communications for substation data collection and remote system control in areas where conventional methods of communication are not available or are too costly.

Our existing OMS draws outage information from three different sources: (1) SCADA System, (2) distribution control system (DCMS), and (3) customer trouble tickets from our Customer Services System (CSS). These data are mapped in OMS to computerized

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

graphical representations of circuit maps to help dispatch crews to restore service. OMS also has the capability of tracking the repair work to completion.

The AMI system, as proposed, is potentially a fourth data source into OMS. While it may be possible to link individual meter service outage data from the AMI system into OMS, it is not currently practical given that OMS outage identification based on our current mapping capabilities does not extend beyond the structure level on a circuit map. We would not be able to cost-effectively increase the level of outage knowledge beyond that which we currently receive from SCADA, DCMS and the greater than 85 percent of customer calls into our phone center that are currently mapped through OMS.

Because we already have adequately functioning OMS, TLM, and SCADA systems,[54] we already obtain associated benefits in our T&D activities.[55] As such, the potential added value related to outage management, transformer loading, and other T&D benefits that otherwise might accompany AMI for some utilities is virtually nonexistent for SCE. We have not included any incremental costs or benefits of AMI relative to these systems in our full and partial deployment scenarios.

C. Major Expected Investments

We have already developed a significant infrastructure including Information Technology (IT) systems necessary to access, validate, and store mass quantities of interval data. We have also developed the necessary interface with the billing system to perform monthly billing for internal meters. The costs associated with this existing internal metering infrastructure are embedded in our rate base, as part of our historical recorded O&M expenses. These embedded costs are very difficult, if not impossible, to separate from other existing metering embedded costs. For this reason, we have developed the costs and benefits

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[54] *Id.*

[55] However, these systems do not address an individual or small pocket of customer outages as would an AMI system. Usually when an individual or pocket outage occurs, the customer calls us. Because the marginal benefit of automatic notification via a meter to a very small number of customers affected for a short period of time is likely to be insignificant, no value was assigned for this preliminary analysis.

for Scenarios 4 and 17 on an incremental cost basis. This means that all cost and benefit estimates are incremental, over and above those currently included in the Business As Usual case.

1. IT Infrastructure Supporting Billing

Although much of the existing IT infrastructure which supports our RTEM and SPP program can be utilized in the AMI deployment scenarios, the existing IT systems have various design limitations which will hinder our ability to directly leverage these investments. The existing, internal meter data handling and billing interfaces were built to process and store data acquired monthly from thousands of accounts, not hundreds of thousands or even millions of accounts as is anticipated in the partial and full AMI deployment cases. The incremental cost of developing and operating the new and expanded IT systems have been included in the cost estimates of each of the deployment scenarios.

2. Meter Reading Infrastructure

Meter reading cost and benefit estimates for each deployment scenario are incremental when compared to the base case. However, one adjustment was made to the Business As Usual capital budget presented in our 2006 GRC. Full or partial deployment of AMI would eliminate the need for replacement of some of the meter readers' electronic hand-held computers. These devices will be out of warranty in 2007 and would otherwise be replaced due to wear and tear and technical obsolescence.[56] For Scenario 4, the overall costs were reduced by $2.9 million (in 2004 PV dollars), to reflect the avoided cost of replacing these devices. For Scenario 17, the overall costs were reduced by $785,000 (in 2004 PV dollars).

3. Meter Replacement Costs

Metering capital costs include not only the material cost of the meter itself, but also the labor cost of the initial installation and the final removal. For purposes of this

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

analysis, the labor cost associated with installing approximately 72,000 new meters annually in response to normal customer growth is not expected to change significantly and has been left in the base case. The labor costs are not included in the full or partial scenario as new costs. Material costs on the other hand will be significantly different for the full and partial AMI deployment scenarios. The difference is the estimated incremental material cost of installing interval meters that meet the AMI functional requirements versus the current metering assets.

Each AMI deployment scenario incorporates the estimated cost of purchasing AMI meters for retrofit, replacement, and customer growth, as well as the avoided costs (benefits) of not purchasing electromechanical meters for replacements and customer growth.

Appendix H

Summary of Potential Benefits

APPENDIX H

SUMMARY OF POTENTIAL BENEFITS

All potential benefits identified in the July 21, 2004 Ruling were considered for inclusion in the analysis of the two revised scenarios. Those benefit codes that were actually used have been addressed separately in each scenario analysis. This Appendix includes a discussion of all of the benefit codes identified in the July 21, 2004 Ruling, whether we used them or not. This summary is presented in two sections, Section I addresses the potential benefits as they relate to full deployment Scenario 4, Section II addresses potential benefits as they relate to partial deployment Scenario 17.

D. Summary of Potential Benefits – Full AMI Deployment

1. System Operations Benefits (SB-1 through SB-13)

Appendix A of the July 21, 2004 Ruling identified 13 potential system operations benefits that may result from deployment of AMI. In our review of these potential benefits, we have been able to quantify savings, coming from four of the 13 benefit codes. We expect some net benefit from two other benefit codes, which we are not able to quantify at this time. The remaining seven potential areas of benefit identified in the July 21, 2004 Ruling are either already being experienced by SCE, have associated costs that more than offset the anticipated savings, or otherwise do not apply.[57] The following sections address all 13 of the potential system operations benefits as described in the July 21, 2004 Ruling.

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

This is the single largest area of operational benefits expected to accrue from AMI. We currently employ approximately 570 meter readers and 80 management and

[57] Several cost codes were found to be duplicative of one another. Where this occurs, we point out the duplicate cost code to avoid double counting.

support personnel, 80 percent of which would be eliminated with full deployment of AMI. As described in Volume 3, full deployment under our "best case" scenario will result in our ability to automatically read 90 percent of all our meters. The remaining 10 percent, or approximately 470,000 meters, will continue to be read monthly by approximately 109 meter readers.[58] In addition, we expect to eliminate 16 of the existing meter reader supervisor positions with full deployment of AMI.[59]

The reduction of 80 percent of our current meter reading organization would result in a total savings of $271 million (expressed in 2004 present value dollars) savings over the duration of the analysis period. With our current attrition rate of 35 to 40 percent annually, the reduction of meter reading personnel is expected to take place through normal attrition during the latter phases of AMI deployment. Attrition is expected to ramp-up beginning with the actual activation of the AMI communications system (approximately 18 months after AMI installations begin) and continue throughout the deployment years. Severance of 32 supervisory personnel will result in a one-time cost of $3 million in 2010 ($1.9 million in 2004 present value dollars). This severance cost is included in cost code MS-1. Additional savings will result from the decommissioning of 80 percent of our hand-held meter reading devices. This savings is reflected in benefit code MB-1.

b) <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

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

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

same day. Such orders can be completed merely by taking a meter read, which currently requires a visit to the site at an average cost of approximately $15 per order. Virtually all of these special meter reads for matched on/off meter orders could be eliminated and replaced with the daily AMI meter read. For the full deployment scenario, this benefit would result in the reduction of approximately 30 FTEs and a savings of approximately $29 million over the duration of the analysis period (*i.e.* through 2021).

c) (SB-3) Reduction in Energy Theft–May Provide Ability to Identify Active Accounts for Metered Accounts Not Being Billed, Broken Meters, Wrong Multipliers

In reviewing this "potential benefit," we were unable to identify any incremental savings that may accrue due to AMI deployment. These situations can be identified by a Meter Reader making an actual observation of the meter installation on a monthly basis. The Meter Reader is our primary means of identifying potential meter tampering and energy theft, especially in those instances where the meter is bypassed or "jumpered" and the integrity of the meter itself is not affected. Although we expect to uncover a number of energy theft situations during the installation phase of AMI that may have otherwise gone undetected, the additional investigators required to resolve these new cases will remain in place after the installation phase in order to complete investigations and make optimum use of information derived from the AMI system to track, monitor and perform ongoing investigations.

Energy consumption on accounts not being billed may be identified more quickly under Scenarios 4 and 17, given that daily reads will be available. This benefit is relatively small and is addressed under "Idle Usage Episodes" in benefit code MB-5 below.

Both energy theft and broken meter situations would be harder–not easier–to identify through AMI, given that physical tampering is not readily apparent through automated meter readings and a zero read does not necessarily indicate a broken meter. Many broken meters continue to register consumption, though it may not be correct.

Rather than identifying any SB-6 benefits, we have actually identified several potential risks related to these collective issues based on today's technology.

d) (SB-4) Phone Center Reduced FTEs in the Long Term Due to Anticipated Lower Customer Call Volume (Estimated / Disputed Bills)

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

Table H-1 shows the number of avoided calls that may result from the complete elimination of meter reading errors. Using 3,376 as the average number of Billing Inquiry calls answered per FTE in the Billing Inquiry specialty support group during 2003, under full deployment we are estimating a levelized reduction of seven FTEs by 2010, for a total benefit of $3.5 million through 2021.

Table H-1
Reduced Phone Calls

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

e) (SB-5) Possible Productivity Enhancement / Rate Changes Simplified / Possible Reprogram Rather Than Meter Change

Some currently-installed TOU meters would require re-programming in the field if the Commission ordered a change in the definition of time-of-use on and off-peak time periods, seasonal definitions, holidays, *etc*. This programming limitation does not exist with AMI meters because they record 15-minute and hourly consumption data.

This is a benefit that SCE will already obtain because we are systematically changing our existing TOU meters to electronic interval data recorders. This effort is expected to be completed by the end of 2005.[60] The value of having the ability to more readily apply time differentiated rates to a vast majority of our customers through full AMI deployment is included in the demand response (DR) benefit codes to be described later.

f) (SB-6) Outage Management Benefits

This potential benefit available from today's AMI technology has been addressed in the Business As Usual case in Appendix G as follows: "Because we already have adequately functioning OMS, TLM, and SCADA systems, we already obtain associated benefits in our T&D activities. As such, the potential added value related to outage management, transformer loading, and other T&D benefits that otherwise might accompany AMI for some utilities is virtually nonexistent for SCE. We have not included any incremental costs or benefits of AMI relative to these systems in our full and partial deployment scenarios."[61]

We have identified some savings attributable to the ability to confirm individual service outages when "no-lights" trouble calls are received at the Call Center. This has been quantified and discussed under benefit code CB-2.

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

The broader range of functionality of new electronic meters, such as those that would be used for AMI, provides advantages over their electro-mechanical predecessors. The most apparent advantage is the universal "one-size-fits-all" capabilities of the modern meter. Although there are still a number of variations in "meter forms," and instrument transformers are still the norm for large accounts, the number of variations is not nearly as broad as it once was. The result is a potential for reduced meter inventories (see benefit code

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[60] SCE's Meter Infrastructure Replacement program is described in SCE's 2006 GRC Application in SCE4 Vol. 2, Chapter V.

[61] *See* Appendix G.

MB-4) and the ability to carry replacements for most meters in field vehicles. Because we are already using RTEM and interval metering for our larger C&I accounts, we are already taking full advantage of this functionality benefit through normal business operations and as captured in the Business As Usual case. This more universal metering functionality is less evident among smaller C&I and residential accounts and is recognized as a qualitative benefit arising from any future AMI deployment.

The incorporation of two-way communications provides the potential for meter diagnostics and voltage verification that do not exist today. AMI meters would also provide the potential means to alert the customers of system peaks and could automatically trigger some form of direct load control. They could also provide a means to allow the customer to access their own metered data for use in reducing consumption during peak periods. These are all recognized as qualitative benefits. However, each of these optional functions carries offsetting costs that are not readily quantifiable at this time. Because incremental costs are not available, we are not able to determine the economics of including any or all of these functional options in this business case analysis.

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

We respond to over 1 million turn-on/turn-off service requests annually, and we disconnect and reconnect nearly 1 million additional meters for credit related, non-payment issues. Nearly one-half of the on/off service requests and all of the credit disconnects require the physical disconnection of service at the customer's meter. AMI meters could be equipped with a remote disconnect switch contained within the meter, which could provide the ability to "remotely" turn electric service on or off.

However, today this is a costly option to be added to an AMI meter as a separate add-on module. A typical 200 amp disconnect switch (not including additional hardware/software necessary to activate) would cost approximately $150 to $200 per meter. By comparison, we currently incur a cost of approximately $17 to respond to a next day on/off service order and approximately $24 for same-day service. Thus, the installation of a remote disconnect switch would only make sense where there is frequent customer turn-over (*i.e.*, student housing, apartment complexes, *etc.*) and/or where credit collection problems exist. Even with turn-over rates of two or three per year at any specific location, the cost effectiveness of this option today is marginal at best. Therefore, we have not included the remote service connect/disconnect functionality in our technology selection, nor have we included any related benefit in any of the AMI deployment scenarios.

i) <u>(SB-9) Meter Accuracy - Improved and More Timely Load Information Could Increase Forecasting Accuracy and Reduce Resource Acquisition Costs and Reduce Customer Complaints About Faulty Meter Reads</u>

A new solid state meter is slightly more accurate over the full range of its rated load capability than its electro-mechanical predecessor. A cost savings has been estimated for reduced call volume relating to billing inquiries as described in SB-4 above. On the other hand, the potential for increased initial failure rates for current AMI technology (as was the case with RTEM meters) has been identified as a potential risk and results in significant cost increases in the Billing Organization due to increased meter order and exception processing (see cost codes CU-1, CU-4, and I-11).

Because customer load information would be available in a more timely manner (*i.e.,* hourly, daily, weekly, *etc.*), it will provide some benefit to SCE with regard to forecasting accuracy and in reducing resource acquisition costs. These costs savings have been identified in Scenario 4 where our Energy Supply and Marketing Organization has included interval data collection and processing costs of $2.3 million (cost code M-15) and forecasting benefits of $3.3 million as part of their on-going operations over the duration of the analysis period.

Benefits derived from improved "billing accuracy" are discussed below under benefit code CB-1.

j) <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 80 to 85 percent of our customers with their serving transformer. SCE already has a Transformer Load Management program in place that already provides this information for distribution planning purposes (see benefit code SB-6). As such, we do not expect deployment of today's AMI technology to create any incremental benefits in this area.

k) <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, 24 hours a day, 365 days per year. This would add over 35 million kWh per year in energy consumption.[62]

l) (SB-12) Ability to Monitor Customer Self-Generation Into System on a Real Time Basis

SCE currently has the capability of metering in 15-minute intervals the energy delivered to (or received from) its self generating customers. Currently, metered data is billed on a monthly basis and none of our tariffs require "real time" monitoring. It is conceivable, however, that some demand response benefit could result from the ability to monitor, in real time, which customers are not generating during peak periods. We have not attempted to estimate the value of this benefit or the cost to implement it. We have included some benefit that is expected to result from our ability to provide the customer with real time, interval consumption data as part of the demand response benefit (see benefit code CB-8 below).

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

The SB-5 benefits addressed above recognize the ability to redefine TOU time periods, or seasons, without the need to physically reprogram meters in the field. The time required to make such a change with the majority of today's meters is actually prohibitive.

2. Customer Service Benefits (CB-1 through CB-13)

The July 21, 2004 Ruling identified 13 "additional" Customer Service Benefits. Our review of these potential areas of benefit resulted in anticipated savings from two of the 13. Total savings in Scenario 4 was $8.3 million. Of this total, $5.4 million is the result of improved billing accuracy due to the elimination of estimated bills, more timely billing, and the elimination of meter accessibility problems (CB-1), and the remaining $2.9 million is the

[62] This could add as much as $1.3 million per year to our cost of energy.

result of ancillary benefits derived from improved web site capabilities necessary to provide interval usage data to customers (CB-8).

This section will address our review and conclusions relating to each of the 13 potential Customer Service Benefits.

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

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

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

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

The two-way radio communications capability of the AMI system would give us the ability to verify whether any particular meter is currently in or out-of-service. This would potentially eliminate the need for a field response to approximately 10 percent of our single-service no-lights calls. This is because approximately 10 percent of single-service no-lights calls have utility service and the interruption is attributable to electrical problems on the customer's side of the meter. We estimate this benefit would eliminate about 2,500 field calls (or roughly 2,500 Troubleman hours) per year, which equates to the full time equivalent of 1.5 Troublemen. To accomplish this savings would require installation of the Call Center systems interface and the necessary communications protocol to facilitate the real-time verification process. We have not attempted to estimate the cost of such a systems interface, but have assumed that the costs would likely offset most of the anticipated benefit. No savings have been included for this benefit code.

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

We do not view AMI as an opportunity for additional meter panel inspections. To the contrary, we consider our meter reader to be our eyes and ears in the field, providing a monthly meter panel inspection and identifying any unsafe conditions, such as dogs, loose or constricted service panels, *etc*. AMI implementation would eliminate this monthly site inspection currently provided by meter readers. This is likely to lead to unforeseen cost increases, not cost savings. No savings have been included for this benefit code.

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

Any potential cost savings for this benefit code have been included in the estimate for benefit code CB-1 above.

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

It seems reasonable to assume that individual customer load profile data would be useful in targeting likely candidates for various future energy efficiency and demand response programs. Until the data becomes available for review, it would be very difficult to determine to what extent such usage information would actually be useful, and what value it might have above and beyond the data available today. No attempt has been made to quantify this potential future benefit.

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

As discussed previously under benefit codes SB-5 and SB-13, full scale implementation of AMI would increase our ability to add new customer rate options. The benefits derived from the ability to expand on new time-differentiated rates are included in the demand response (DR) benefits.

g) (CB-7) Customized Billing Date

Because we would no longer be locked in to fixed meter-reading cycles, it would be possible to offer AMI metered customers a choice of when, during the month they would prefer to be billed. This could conceivably provide some cash-flow and/or payment flexibility benefit to those customers. It is hard to see how this provides any direct benefit to SCE, however, beyond some level of improved customer satisfaction which is difficult to quantify. It is also likely that any cash flow advantage to large customers, taking advantage of timing their own cost cycle, could result in a cash-flow disadvantage to SCE. No value has been included for this benefit code.

AMI would also give SCE the ability to change billing dates to enable more efficient use of billing cycles and to improve cash flow from its summary billing accounts. This benefit is discussed in benefit code MB-5.

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

We expect a direct benefit of approximately $2.9 million as part of the demand response analysis resulting from usage data availability to customers through SCE's website. This benefit is largely offset by the added cost of expanding the web site capacity to accommodate this anticipated increase in activity. These offsetting website costs are included in cost code CU-9.

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

The prospect of today's AMI technology opening-up an array of potentially new business ventures is highly speculative. To what extent SCE would be able to participate in these new, undefined business ventures is unclear at this point and no value has been included for this benefit code.

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

SCE's current load surveys utilize 15-minute interval data for the residential, GS-1 (small commercial below 20 kW), GS-2 (20 to 200 kW) and agricultural customer samples. Our AMI deployment assumptions stipulate that, 15-minute data would normally be retrieved only from customers with demands above 20 kW. With special programming, we believe we would be able to retrieve 15-minute data for a select group (a statistical sample) of residential and GS-1 accounts as well. This would eliminate the need for special metering at load survey sites. The cost of performing the load survey sample design and analysis would, however, still remain.

In Scenario 4, we have included all load survey metering costs in our avoided cost of new and replacement meters in benefit code MB-4.

k) (CB-11) On-line Bill Presentment With Hourly Data / More Timely and Accurate Information About Electricity / Information Access

See discussion under benefit code CB-8.

l) (CB-12) Value to Customers of More Timely And Accurate Bills

See discussion under benefit codes CB-1, CB-4 and CB-7.

3. Demand Response Benefits [DR-1 through DR-4]

The July 21, 2004 Ruling identified four potential Demand Response benefit categories to be evaluated in the business cases. Those categories are:

- DR-1: Procurement cost reduction;
- DR-2: System reliability benefits (capacity buffer);
- DR-3: Dynamic fuel switching/dynamic integration of conventional and distributed supplies; and
- DR-4: Avoided/deferred transmission and distribution (T&D) additions / upgrade costs.

For SCE, only DR-1 and DR-2 provide quantifiable benefits that should be included in the business case analyses. Our approach and assumptions for each Demand Response benefit category is described in the following sections.

a) DR-1: Procurement Cost Reduction

TDRs enabled by AMI that result in peak load and energy reductions would yield a reduction in the utility's procurement costs. Such costs that are truly avoided should be counted as benefits in the business case. Avoided costs can be estimated by a "proxy method" where a simple assumption is made that the procurement costs avoided are calculated assuming a single avoided resource cost for capacity and for energy, at all times, as an approximation of the actual costs avoided which in practice vary hour by hour and day by day.

The Commission directed parties to use a "proxy method" namely, $85/kW-yr for capacity savings and $70/MWh ($63/MWh for peak energy plus $7/MWh for congestion) for the energy savings provided by TDR load reductions. Off-peak energy was assigned a value of $45/MWh. The values for peak energy are similar to the levelized capital cost of a combustion turbine (CT) operating at a gas price of close to $6/MMBTU.

The avoided resource value of demand response from TDRs and different characteristics than a CT and their respective values, as resource are not equivalent. SCE used both the required avoided cost values provided in the July 21, 2004 Ruling and adjusted avoided resource values for the capacity component of avoided procurement costs as set forth in Appendix D.

Finally, we applied a distribution loss factor adjustment by increasing the capacity and energy benefits by 8.4 percent. This is a reasonable proxy for distribution losses at peak times (high temperatures) that would be incurred by generation supplies.[63]

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

b) DR-2: System Reliability Benefits (Capacity Buffer)

We agree that for load reductions from "reliable" load response to TDRs, reserve requirements are avoided. We apply a system reliability benefit of 15 percent reserves to the counted load response. We calculate a value for this benefit at the avoided capacity cost defined by the July 21, 2004 Ruling ($85/kW-year) and by what we believe to be our actual avoided marginal reserve cost of $80/kW-year.

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

TDRs enabled by AMI do not provide reliable and rapid response that would enable or improve the dispatch of resources on our system above and beyond the current methods and system capabilities. For example, we have system monitoring and metering at a substation level. It unclear how increased granularity from interval metering at the end use will provide us additional information to facilitate fuel switching or the integration of distributed generation. For purposes of this analysis, the avoided cost savings attributable to AMI for dynamic integration benefits are included in the capacity payment since this payment reflects the cost of a combustion turbine that provides full dispatch capability. Including a separate adder would amount to double counting the savings attributable to dynamic integration benefits.

AMI metering at the residential level is not likely to be aggregated or evaluated in a way timely for fuel switching. AMI does not provide measurable benefits since the amount of energy saved by the AMI program is minimal. Significant fuel diversity savings are caused by programs that save a significant amount of energy thereby affecting the fuel mix required to produce energy.

Moreover, it is unknown how such information, assuming more geographic granularity is better, would translate to quantifiable benefits. Of course, if there were potential benefits to consider, the costs associated with the required systems and applications would also need to be included. Accordingly, without better information concerning this category at this point, we have omitted any potential benefit from fuel switching.

d) DR-4: Avoided/Deferred Transmission and Distribution (T&D) Additions/Upgrade Costs

For a number of reasons, we do not believe that TDRs enabled by AMI provide transmission and distribution upgrade deferral benefits. We first describe below transmission upgrade issues and then explain distribution upgrade issues.

Transmission network upgrades or expansions are required to avoid congestion. However, congestion on specific transmission lines can be caused by generator or system outages and more typically occurs during shoulder months rather than at peak times, when most supply-side resources are available. In fact, reductions in load in certain locations on the network could cause congestion in other areas. Secondly, TDRs are subject to change. If a transmission upgrade was deferred due to expected demand reduction from a TDR and the rate is modified or discontinued, as in the case of Puget Sound Energy explained earlier, system reliability could be immediately threatened. Ultimately, there is a possibility that significant and durable demand response could result in deferring transmission upgrades. However, we believe that counting such benefits in a business case when Commission and legislative intervention in rates has been demonstrated in the past, such as in the case of AB1-X, is not appropriate.

With respect to distribution additions/upgrades, we believe that it is not appropriate to count distribution upgrade deferrals as benefits due to uncertainty concerning rates. In addition, TDRs, especially if CPP programs were implemented widely, could actually cause more simultaneous loading on the distribution network when the rate changes from peak to off peak. For example, assume a residential distribution circuit sized to handle 20 MW of otherwise diversified residential customer load. By signaling a CPP event, customers are encouraged to not use energy during a set peak period. When the CPP event ends and those customers who responded to the program begin to use energy again, there is a risk that the increased coincidence associated with this load will create a higher than otherwise peak load on that distribution circuit. At the end of the CPP event, air conditioners are working hard to bring the temperature down to the desired comfort level at off-CPP peak prices. If there were a high number of customers on a CPP rate during a hot peak summer day the coincident peak loading of the simultaneous turn on of air conditioner compressors is called a "rebound effect."

The phenomenon of distribution system loading can be understood by examining the actual load profile of SPP participants on a CPP day where a higher peak than would otherwise occur was observed in the evening hours.

4. Management and Other Benefits (MB-1 through MB-10)

Only two of the ten potential "Management and Other" benefit codes identified in the July 21, 2004 Ruling were actually used in SCE's analysis. The following sections describe our review of each of the potential Management and Other benefit codes.

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

In Scenario 4, we expect to reduce costs by approximately $2.9 million over the duration of the analysis period by decommissioning 80 percent of our hand-held meter reading devices. Typically these electronic devices would be replaced every five years. This is a cost that would no longer be incurred under full AMI deployment.

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

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

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

Because SCE has already begun to use interval metering for its TOU and interval data needs, no incremental savings would accrue as a result of replacing existing metering with AMI meters. See related discussion under benefit code SB-5.

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

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

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

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

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

f) (MB-6) Possible Reduction In "Idle Usage," Meter Watt Losses – at the Very Least, Quicker Resolution of Idle Usage Episodes.

AMI meters have the ability to meter smaller loads (below 25 watts) than do existing electromagnetic meters. Most electromagnetic meter discs sit "idle" when less than 20 to 25 watts are being consumed. Our review of our existing residential load survey data shows that some minimum load between 0 and 25 watts exists approximately 3.5 percent of the time (*i.e.*, approximately one hour per day, on average). Though significant time-wise, the actual energy consumed during this un-metered hour is less than 0.004 percent of total metered kWh on average. For an average residential customer, this would equal approximately 25 watt-hours per month. On an annual basis, we estimate that under full deployment, all AMI meters would meter a total of approximately 1.4 million kWh per year (approximately $60,000 in energy costs) more than their electromagnetic predecessors. More accurate measurement of this energy would not result in any cost savings, but merely in a reallocation of these costs to those customers responsible for this currently un-metered load.

Because the value of this unmetered load is so small, we have not included any savings attributable to this benefit in the full or partial deployment scenarios.

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

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

g) <u>(MB-7) Possible New Revenue Source / New Business Ventures / New Products and Services / Web Based Interval and Power-Quality Data</u>

See discussion under benefit code CB-9 above.

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

GPS reads will be recorded for all meter locations during the installation phase of AMI deployment. This will be done in order to be able to mark the actual location of the meter site, since it may be several years before we will ever have to revisit the meter. The GPS read will reduce the odds of physically "losing" the meter as customers add walls and fences, making it difficult to keep track of the meter and its access route. It is conceivable that these GPS reads can be incorporated into the Franchise Payment and Utility User Tax processes, in order to assure more accurate processing of these fees. Because there would be offsetting costs to develop the systems interface to facilitate the use of GPS readings, a much more intense review of costs and benefits would have to be undertaken to determine the economic feasibility of this potential benefit.

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

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

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

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

All benefit codes identified in the July 21, 2004 Ruling, are discussed in the following sections, whether included in the final business case analysis or not.

E. Summary of Potential Benefits Partial AMI Deployment

All benefit codes identified in the July 21, 2004 Ruling are discussed in the following sections, whether in the analysis or not.

1. System Operations Benefits (SB-1 through SB-13)

Appendix A of the July 21, 2004 Ruling identified 13 potential system operations benefits that may result from deployment of AMI. In our initial review of these potential benefits, we have been able to quantify savings coming from three of the 13 benefit codes for a total of $29.3 million for all partial deployment scenarios. We expect some net benefit from two other benefit codes, which we are not able to quantify at this time. The remaining seven potential areas of benefit identified in the July 21, 2004 Ruling are either already being experienced by SCE, have associated costs that more than offset the anticipated savings, or otherwise do not apply.[64] The following sections address all 13 of the potential system operations benefits as described in the July 21, 2004 Ruling.

a) (SB-1) Reduction in Meter Readers, Management, and Administrative Support (And Associated Costs)

This is the single largest area of benefits expected to accrue from partial implementation of AMI. We expect 32 meter reading positions will be eliminated, resulting in total cost savings of approximately $26.3 million over the analysis period. We expect AMI will give us the ability to remotely read approximately 70 percent of all meters in Zone 4 (70 percent of 442,000 = 309,000). The remaining 133,000 meters that cannot be read through the AMI system will continue to be read manually on a monthly basis by approximately 40 Meter Readers.[65] We do not expect to eliminate any of the existing Meter Reader Supervisor positions under the partial deployment scenarios since each of the three major districts involved have only one supervisor who oversees both Field Services and Meter Reading field activities. Additional savings will result from the decommissioning of 30 hand-held meter reading devices. This savings is reflected in benefit code MB-1.

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[64] Several cost codes were found to be duplicative of one another. Where this occurs, we point out the duplicate cost code to avoid double counting.

[65] The remaining 30 percent of the meters with which we are unable to communicate are scattered throughout the Zone 4 area and are generally not adjacent to one another, thus making routine meter reading less efficient than it is today.

b) <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. Under partial AMI deployment, this benefit would result in the reduction of five FTEs and approximately $2.8 million in total costs over the duration of the analysis period.

c) <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 Scenarios 4 and 17, given that daily reads will be available. This benefit is relatively small and is addressed under "Idle Usage Episodes" in benefit code MB-5 below.

We believe both energy theft and broken meters would be harder–not easier–to identify through AMI, given that physical tampering is not readily apparent through automated meter readings and a zero read does not necessarily indicate a broken meter. Many broken meters continue to register consumption, though it may not be correct. Rather than identifying any SB-6 benefits, we have actually identified several potential risks related to these collective issues using today's AMI technology.

d) (SB-4) Phone Center Reduced FTEs in the Long-Term Due to Anticipated Lower Customer Call Volume (Estimated / Disputed Bills)

Billing inquiries today are received for several reasons, only one of which is an inaccurate meter read. Based on a study using 2003 data, 22,791 inquiries to the Call Center were a result of meter reading errors. We used this number as a percentage of all calls to determine the percent of calls in subsequent years that would be projected as meter read error calls. For purposes of this analysis, we assume that 100 percent of these calls currently coming from Zone 4 will be avoided with the partial (Zone 4) deployment of AMI.

Table H-2 shows the number of avoided calls that may result from the elimination of meter reading errors in Zone 4. Using 3,376 as the average number of Billing Inquiry calls answered per FTE in the Billing Inquiry specialty support group during 2003, under partial deployment we estimate a reduction of 0.6 FTEs for a total benefit of $0.4 million through 2021.

Table H-2 Reduced Phone Calls						
Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Partial Deployment	0	2,216	2,216	2,216	2,216	2,216

e) (SB-5) Possible Productivity Enhancement / Rate Changes Simplified / Possible Reprogram Rather Than Meter Change

Some currently-installed TOU meters would require re-programming in the field if the Commission ordered a change in the definition of time-of-use on and off-peak time periods, seasonal definitions, holidays, *etc*. This programming limitation does not exist with AMI meters because they record 15-minute and hourly consumption data.

This is a benefit that SCE will already obtain because we are systematically changing our existing TOU meters to electronic interval data recorders. This effort is expected to be completed by the end of 2005.[66] The value of having the ability to more readily apply time differentiated rates to a vast majority of our customers through AMI deployment is included in the demand response (DR) benefit codes to be described later.

f) (SB-6) Outage Management Benefits

This potential benefit of today's AMI technology has been addressed in the Business As Usual case in Appendix G as follows: "Because we already have adequately functioning OMS, TLM, and SCADA systems, we already obtain associated benefits in our T&D activities. As such, the potential added value related to outage management, transformer loading, and other T&D benefits that otherwise might accompany AMI for some utilities is virtually nonexistent for SCE. We have not included any incremental costs or benefits of AMI relative to these systems in our partial deployment scenarios."[67]

66 SCE's Meter Infrastructure Replacement program is described in SCE's 2006 GRC Application in SCE4 Vol. 2, Chapter V.

67 *See* Appendix G.

We have identified some savings attributable to the ability to confirm individual service outages when "no-lights" trouble calls are received at the Call Center. This has been quantified and discussed under benefit code CB-2.

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

The broader range of functionality of new electronic meters, such as those that would be used for AMI, provides advantages over their electro-mechanical predecessors. The most apparent advantage is the universal "one-size-fits-all" capabilities of the modern meter. Although there are still a number of variations in "meter forms," (the configuration of the meter stabs connecting it to the panel socket) and instrument transformers are still the norm for large accounts, the number of variations is not nearly as broad as it once was. The result is a potential for reduced meter inventories (see benefit code MB-4) and the ability to carry replacements for most meters in field vehicles. Because we are already using RTEM or interval metering for our larger C&I accounts, we are already taking full advantage of this functionality benefit through normal business operations and as captured in the "Business As Usual" case. This more universal metering functionality is less evident among smaller C&I and residential accounts and is recognized as a qualitative benefit arising from any future AMI deployment.

The incorporation of two-way communications provides the potential for meter diagnostics and voltage verification that do not exist today. AMI meters would also provide the potential means to alert the customers of system peaks and could automatically trigger some form of direct load control. They could also provide a means to allow the customer to access their own metered data for use in reducing consumption during peak periods. These are all recognized as qualitative benefits. However, each of these optional functions carries offsetting costs that are not readily quantifiable at this time. Since incremental costs are not available, we are not able to determine the economics of including any or all of these functional options in this analysis.

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

We respond to over 1 million turn-on/turn-off service requests annually, and we disconnect and reconnect nearly 1 million additional meters for credit related, non-payment issues. Nearly one-half of the on/off service requests and all of the credit disconnects require the physical disconnection of service at the customer's meter. AMI meters could be equipped with a remote disconnect switch contained within the meter, which could provide the ability to "remotely" turn electric service on or off.

However, this is a costly option to be added to an AMI meter. A typical 200 amp disconnect switch (not including additional hardware/software necessary to activate) would cost approximately $150 to $200 per meter. By comparison, we currently incur a cost of approximately $17 to respond to a next day on/off service order and approximately $24 for same-day service. Thus, the installation of a remote disconnect switch would only make sense where there is frequent customer turn-over (*i.e.*, student housing, apartment complexes, *etc.*) and/or where credit collection problems exist. Even with turn-over rates of two or three per year at any specific location, the cost effectiveness of this option today is marginal at best. Therefore, we have not included the remote service connect / disconnect functionality in our technology selection, nor have we included any related benefit in the partial deployment scenarios.

i) (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 current AMI technology (as was the case with RTEM meters) has been identified as a potential risk and results in significant cost increases in the Billing Organization due to increased meter order and exception processing (see cost codes CU-1, CU-4, and I-11).

Because customer load information would be available in a more timely manner (*i.e.,* hourly, daily, weekly, *etc.*), full AMI deployment will provide some benefit to SCE with regard to forecasting accuracy and in reducing resource acquisition costs. These costs savings have been identified in the demand response analysis.[68] No similar benefit has been included for partial AMI deployment.

Benefits derived from improved "billing accuracy" are discussed below under benefit code CB-1.

j) (SB-10) System Planning Design Efficiency – Savings from More Accurate Information on Status of Transformers And Distribution Lines Etc.

In theory, AMI would give us the opportunity to aggregate coincident customer loads within any specific area in order to determine the demand on a distribution circuit or an individual distribution transformer. In reality, however, distribution circuit loads are dynamic and cannot be assumed to be confined to any geographic area over any extended period of time. This is because sections of load are constantly being switched from one circuit to another (and from one transformer to another) during circuit interruptions, for routine maintenance, and for load balancing purposes. We estimate that we are currently able to match only 80 to 85 percent of our customers with their serving transformer at any given time. SCE already has a Transformer Load Management program in place that already provides this information for distribution planning purposes (see benefit code SB-6). As such, we do not expect deployment of today's AMI technology to create any incremental benefits in this area.

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[68] *See* Appendix C.

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

As described above, AMI could theoretically give us the opportunity to aggregate customer loads within any specific geographic area in order to determine the demand on any particular distribution circuit. Even if this were technically feasible, it is not clear how this aggregated load information will assist in identifying the source of UFE.

We currently have the ability to analytically model system losses using customer load profile data compared to total system generation, and have concluded that the amount of UFE is not significant enough to warrant any further investigation of the sort suggested as a potential benefit under AMI deployment.

The "watts lost" rating of an electronic meter is typically greater than that of the single phase electro-mechanical meter it would be replacing. We estimate the average AMI meter would be rated at approximately one watt higher than their single phase electro-mechanical counterparts.

l) (SB-12) Ability to Monitor Customer Self-Generation Into System on a Real Time Basis

SCE currently has the capability of metering in 15-minute intervals the energy delivered to (or received from) its self generating customers. Currently, metered data is billed on a monthly basis and none of our tariffs require "real time" monitoring. It is conceivable, however, that some demand response benefit could result from the ability to monitor, in real time, which customers are not generating during peak periods. We have not attempted to estimate the value of this benefit or the cost to implement it. We have included some benefit that is expected to result from our ability to provide the customer with real time, interval consumption data under the demand response scenarios (see benefit code CB-8 below).

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

The SB-5 benefits addressed above recognize the ability to redefine TOU time periods, or seasons, without the need to physically reprogram meters in the field. The time required to make such a change with the majority of today's meters is actually prohibitive. However, for the vast majority of customers on TOU rates, there has not been a compelling reason to redefine time periods or seasons in recent years. As part of the demand response analysis, the ability to implement new rates in a timely manner, especially rates with narrower on-peak periods (or variable peak periods), would be a significant qualitative benefit and would eliminate a major obstacle to periodically re-defining TOU periods when warranted.

Under Scenario 17, we see no incremental savings attributable to this potential benefit over our "Business As Usual" base case. This is because we are already replacing our existing pre-programmed TOU meters with interval meters, and thus we will already derive this benefit. With regard to the demand response scenarios, as was the case with benefit code CB-5, the benefits to be derived from optimizing customer participation on various new rate options is included in the demand response (DR) benefits.

2. Customer Service Benefits (CB-1 through CB-13)

The July 21, 2004 Ruling identified 13 "additional" customer service benefits. Our review of these potential areas of benefit under partial AMI deployment resulted in anticipated savings from three of the thirteen, for a total savings of approximately $4.0 million in the demand response benefit. Of this total, $1.1 million is the result of improved billing accuracy due to the elimination of estimated bills, more timely billing, and the elimination of meter accessibility problems (CB-1), the remaining $2.9 million is the result of ancillary benefits derived from improved website capabilities necessary to provide interval usage data to customers (CB-8). This section will address our review and conclusions relating to each of the 13 potential Customer Service Benefits under partial AMI deployment.

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

Inaccessible and/or locked meter sites are the primary reason for estimated and or un-timely bills. Automated retrieval of meter reads eliminates these meter access problems and reduces the need to estimate monthly meter reads. This, in turn, eliminates the need for many "pick-up" reads and billing inquiry investigations. We have estimated the savings related to this benefit to be approximately $1.1 million for Scenario 17 over the duration of the analysis period.

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

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

The two-way radio communications capability of the AMI system would give us the ability to verify whether any particular meter is currently in or out-of-service. This would potentially eliminate the need for a field response to approximately 10 percent of our single-service no-lights calls. This is because approximately 10 percent of single-service no-lights calls have utility service and the interruption is attributable to electrical problems on the customer's side of the meter. We estimate this benefit would eliminate about 2,500 field calls (or roughly 2,500 Troubleman hours) per year, which equates to the full time equivalent of 1.5 Troublemen. To accomplish this savings would require installation of the Call Center systems interface and the necessary communications protocol to facilitate the real-time verification process. We have not attempted to estimate the cost of such a systems interface, but have assumed that the costs would likely offset most of the anticipated benefit. No savings have been included for this benefit code.

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

We do not view AMI as an opportunity for additional meter panel inspections. To the contrary, we consider our meter reader to be our eyes and ears in the field, providing a monthly meter panel inspection and identifying any unsafe conditions, such as dogs, loose or constricted service panels, *etc*. AMI implementation would eliminate this monthly site inspection currently provided by meter readers. This is likely to lead to unforeseen cost increases, not cost savings. No savings have been included for this benefit code.

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

Any potential cost savings for this benefit code have been included in the estimate for benefit code CB-1 above.

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

It seems reasonable to assume that individual customer load profile data would be useful in targeting likely candidates for various future energy efficiency and demand response programs. Until the data becomes available for review, it would be very difficult to determine to what extent such usage information would actually be useful, and what value it might have above and beyond the data available today. No attempt has been made to quantify this potential benefit.

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

As discussed previously under benefit codes SB-5 and SB-13, implementation of AMI would increase our ability to add new customer rate options. The benefits derived from the ability to expand on new time-differentiated rates are included in the demand response (DR) benefits.

g) (CB-7) Customized Billing Date

Because we would no longer be locked in to fixed meter reading cycles, it would be possible to offer AMI metered customers a choice of when, during the month they would prefer to be billed. This could conceivably provide some cash-flow and/or payment flexibility benefit to those customers. It is hard to see how this provides any direct benefit to SCE, however, beyond some level of improved customer satisfaction which is difficult to quantify. It is also likely that any cash flow advantage to large customers, taking advantage of timing their own cost cycle, could result in a cash-flow disadvantage to SCE. No value has been included for this benefit code.

AMI would also give us the ability to change billing dates to enable more efficient use of billing cycles and to improve cash flow from its summary billing accounts. This benefit is discussed in benefit code MB-5.

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

We expect a direct benefit of approximately $2.9 million as part of the demand response benefits resulting from usage data availability to customers through SCE's website. This benefit is largely offset by the added cost of expanding the web site capacity to accommodate this anticipated increase in activity. These offsetting website costs are included in cost code CU-9.

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

The prospect of AMI opening-up an array of potentially new business ventures is highly speculative. To what extent we are able to participate in these new undefined business ventures is unclear at this point and no value has been included for this benefit code.

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

Partial deployment of AMI would not provide the appropriate statistical representation of the total SCE system that is required for load survey purposes. The full deployment case addresses savings for this benefit code.[69]

k) (CB-11) On-line Bill Presentment With Hourly Data/More Timely and Accurate Information About Electricity/Information Access

See discussion under benefit code CB-8.

l) (CB-12) Value to Customers of More Timely & Accurate Bills

See discussion under benefit codes CB-1, CB-4 and CB-7.

3. Demand Response Benefits

The July 21, 2004 Ruling identified four potential Demand Response benefit categories to be evaluated in the business cases. Those categories are:

a) DR-1: Procurement cost reduction;

b) DR-2: System reliability benefits (capacity buffer);

c) DR-3: Dynamic fuel switching / dynamic integration of conventional and distributed supplies; and

d) DR-4: Avoided/deferred transmission and distribution (T&D) additions / upgrade costs.

For SCE, only DR-1 and DR-2 provide quantifiable benefits that should be included in the business case analyses.

4. Management and Other Benefits

Only two of the 10 potential "Management and Other" benefit codes identified in the July 21, 2004 Ruling were actually used in SCE's analysis. The following sections describe our review of each of the potential Management and Other benefit codes.

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[69] *See* Volume III, Section IV.

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

For Scenario 17, 30 hand-held meter reading devices would be decommissioned for a total savings of $785,000. Typically these electronic devices would be replaced every five years. This is a cost that would no longer be incurred under partial AMI deployment.

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

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

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

Because SCE has already begun to use interval metering for its TOU and interval data needs, no incremental savings would accrue as a result of replacing existing metering with AMI meters. See related discussion under benefit code SB-5.

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

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

This benefit code contains our avoided cost of purchasing approximately 6,300 conventional new and replacement meters each year for the full duration of the analysis period. As discussed in the Business As Usual case (Appendix G) the material cost of 6,300 new and replacement non-AMI meters each year is significantly different than the replacement cost of these same 6,300 meters each year using AMI meters. For this reason, the total cost of all new and replacement AMI meters has been included in the full and partial AMI deployment scenarios in cost code MS-3. The avoided cost of not purchasing conventional meters for customer growth and routine replacements is included as a savings in this benefit code. For Scenario 17, this avoided cost is $10.5 million over the duration of the analysis period.

e) (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. Full deployment of AMI would allow us to synchronize the read dates for all service accounts on summary bills, virtually eliminating the current revenue lag. However, under Scenario 17, we do not expect to gain any improvement in cash flow since we expect not enough individual service accounts could be synchronized to justify the necessary program and systems expenses to accomplish the needed changes.

f) (MB-6) Possible Reduction In "Idle Usage", Meter Watt Losses – at the Very Least, Quicker Resolution of Idle Usage Episodes.

AMI meters have the ability to meter smaller loads (below 25 watts) than do existing electromagnetic meters. Most electromagnetic meter discs sit "idle" when less than 20 to 25 watts are being consumed. Our review of our existing residential load survey data shows that some minimum load between 0 and 25 watts exists approximately 3.5 percent of the time (*i.e.*, approximately one hour per day on average). Though significant time-wise, the actual energy consumed during this un-metered hour is less than 0.004 percent of total metered kWh on average. For an average residential customer, this would equal approximately 25 Watt-hours per month. On an annual basis, we estimate that under partial deployment, AMI meters would meter a total of approximately 140,000 kWh per year (approximately $6,000 in energy costs) more than their electromagnetic predecessors. More accurate measurement of this energy would not result in any cost savings, but merely in a reallocation of these costs to those customers responsible for this currently un-metered load. Because the value of this unmetered load is so small, we have not included any savings attributable to this benefit in the full or partial deployment scenarios.

The "watts lost" rating of an electronic meter is typically greater than that of the single phase electro-mechanical meter it would be replacing. We estimate the average AMI meter would be rated at approximately one watt higher than their single phase electro-mechanical counterparts. Taken on its own, this technical characteristic of electronic meters would add four megawatts of load 24 hours a day, 365 days per year. This would add over three million kWh per year in energy consumption for the Scenario 17.

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

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

See discussion under benefit code CB-9 above.

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

GPS reads will be recorded for all meter locations during the installation phase of AMI deployment. This will be done in order to be able to mark the actual location of the meter site, since it may be several years before we will ever have to revisit the meter. The GPS read will reduce the odds of physically "losing" the meter as customers add walls and fences, making it difficult to keep track of the meter and its access route. It is conceivable that these GPS reads can be incorporated into the Franchise Payment and Utility User Tax processes, in order to assure more accurate processing of these fees. Because there would be offsetting costs to develop the systems interface to facilitate the use of GPS readings, a much more intense review of costs and benefits would have to be undertaken to determine the economic feasibility of this potential benefit.

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

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

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

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

Appendix I

Estimating Large Customer Demand Reductions from Two-Part RTP

APPENDIX I

ESTIMATING LARGE CUSTOMER DEMAND REDUCTIONS FROM TWO-PART RTP

The July 21, 2004 Ruling required the analysis of large commercial and industrial customers (>200 kW) placed on a default basis to a two-part real time tariff, as part of certain AMI scenarios. This requirement could be interpreted to apply to Scenario 4. However, we believe that the consideration of the impact of a rate change on large customers is of interest but not as an AMI business case. This is because the investment in advanced metering for this customer class is already sunk. Since the July 21, 2004 Ruling, the Commission required utilities to make proposals to move the large customer class from TOU to CPP rates on a default basis. Should the Commission order CPP rates be implemented to this class on a default basis, the analysis of moving customers to RTP is significantly altered.

In compliance with the July 21, 2004 Ruling, our October 2004 and January 2005 preliminary business case analyses contained our analysis on two variations of implementing RTP and was submitted as Scenarios 12 and 13. In Scenario 12, we assumed that all large customers with RTEM meters are placed on a RTP rate on a mandatory basis. For Scenario 13, we assumed that our current Schedule I-6 interruptible program is maintained and all other large customers are placed on a RTP rate. Thus, Scenario 12 is a study of large customers on an RTP rate and Scenario 13 evaluates the mandatory implementation of RTP plus reliability provided by Schedule I-6.

This appendix describes the operational costs and benefits of these scenarios and provides our methodology for estimating demand response from two-part RTP.

A. Operational Costs

For Scenarios 12 and 13, we expect to incur certain information technology infrastructure costs that we have preliminarily estimated at $0.3 million for each scenario in costs codes C-3, C-4, C-10 and I-1. In addition, we expect to incur customer education and marketing costs for those customers taking advantage of the default two-part RTP rate schedules. For this preliminary analysis, we estimate these costs at $17.5 million for both scenarios in cost codes CU-10 and M-14.

As shown below in Table I-1, the only difference between Scenarios 12 and 13 pertain to expected customer acquisition costs for the rate incentives that would be paid to Rate Schedule I-6 customers. For this analysis, we forecast incentive costs of approximately $355.5 million.

Table I-1
Summary of Costs for Scenarios 12 and 13
(000s in 2004 Pre-Tax Present Value Dollars)

	Scenario 12	**Scenario 13**
Cost Categories	**Total**	**Total**
Metering System Infrastructure	$0	$0
Communications Infrastructure	0	0
Information Technology Infrastructure	327	327
Customer Service Systems	0	0
Management and Miscellaneous Other	17,500	17,500
Rate Incentives for Schedule I-6	0	355,500
TOTAL:	$17,827	$373,327

B. Benefits For Scenarios 12 and 13

Scenario 12 evaluates the demand response benefits of RTP for all large C&I customers above 200 kW. Scenario 13 evaluates the demand response benefits of RTP for all large C&I customers above 200 kW plus the reliability benefits of maintaining Schedule I-6 customers. We estimated a peak MW reduction using the following methodology and escalated that reduction per year based on customer growth for the class.

We applied the Commission's assumptions for capacity value of $85/kW-yr. A distribution loss factor of 8.4 percent was then applied to capacity benefits. We have not adjusted the above demand response benefits for Value of Service Loss to customers due to participation in TDRs. We believe such an adjustment would apply, however, we would require additional information about the actual RTP rates to employ our methodology. The results of our analysis of the benefits are shown in Table I-2 below.

Table I-2
Summary of Benefits for Scenario 12
(Millions in 2004 Pre-Tax Present Value Dollars)

	Scenario 12	**Scenario 13**
Benefit Categories	**Total**	**Total**
Systems Operations Benefits	$0	$0
Customer Service Benefits	$0	$0
Management and Other Benefits	$0	$0
Demand Response Benefit DR-1	$112	$382
Demand Response Benefit DR-2	$16	$53
TOTAL:	$128	$435

C. Uncertainty and Risk Analysis

No risk analysis of cost or operational benefit was performed for these scenarios as the costs and associated risks are relatively low given our knowledge of the existing system and that no incremental operational benefits were identified.

The load reductions from RTP are untested in recent years in SCE territory and therefore unknown. Also, we did not examine potential rate design issues associated with RTP. No market-based real-time prices exist in California so an RTP rate would have to be based on a proxy of market prices or actual real-time costs to the utility. We also do not know how customers would react to mandatory RTP. Current industry literature indicates that, while some large customers can adjust usage, others cannot.

D. Net Present Value Analysis

Table I-3 summarizes the Net Present Value results for Scenarios 12 and 13.

Table I-3
Summary of Cost/Benefit Analysis for Scenarios 12 and 13
($Millions)

	Costs	Benefits	Pre-Tax NPV
Scenario 12	$18	$128	$110
Scenario 13	$373	$435	$62

1. Methodology

This section describes how we developed an estimate of the MW savings at system peak from firm and interruptible customers who would potentially be on RTP rates. The July 21, 2004 Ruling required a business case analysis of two-part RTP rates but we were unable to perform such an analysis directly without additional guidance on a specific rate design and other factors. Consequently, CEC staff recommended that the utilities rely on prior studies on RTP implementation. Thus, our basic approach was to start with the results of the study that Christensen Associates performed for the California Energy Commission (CEC)[70] to estimate the statewide savings due to the potential implementation of RTP across the three major investor-owned utilities (IOUs) in the state. We applied those results, by Standard Industrial Classification (SIC) code, to the population of SCE customers with peak demands over 200 kW.

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

E. Description of the Christensen Report

The Christensen Report was based primarily on an analysis of Georgia Power's RTP program, serving about 1,600 large C&I customers. The analysis showed that the degree of price-responsiveness to RTP rates was related to SIC code. The report provides a list (Table 2 in the report) of 18 SIC codes that were found to be price responsive to some degree. For each SIC code, the report further disaggregated these groups into high, moderate, and low responders, and provided the percentage of Georgia Power customers that had each level of responsiveness for each SIC code. The report provided one elasticity parameter (the peak-period elasticity of substitution) for each responsiveness level for each SIC code.

Using statewide population information, PG&E's dynamic load profiles, historic rates, and historic "pre-energy crisis" wholesale costs, Christensen estimated the total statewide load savings at the system peak for each SIC code, for both a "very high price day" and a "high price day." The load savings by SIC code, both on an absolute and a percentage basis, is shown in table 4 of the report. Note that these savings (a total of 814 MW, or about 17 percent of the total load for the group on the very high price days) represent the expected statewide savings.

F. Determining Impacts on SCE's System Peak

In order to determine the impact on SCE's system peak from SCE's customers with peak demands over 200 kW, we first summarized the contribution to the system peak for these customers by SIC code and rate (including firm vs. interruptible). We then applied the percent load savings for each price-responsive SIC Code from Table 4 of the Christensen Report, using the very high price day information (in order to reflect the load likely to be dropped on extreme days), and totaled the load reductions across the SIC codes to estimate the total load reductions that SCE can expect if RTP tariffs are applied to all customers over 200 kW. Those SIC codes that were not listed in the report were not price responsive, so we assumed that there would be no load reduction by SCE customers in those SIC groups.

Most of the current SCE population of customers with demand over 200 kW already have interval data recorders, but some do not. Contribution to the 2003 system peak data were available for 10,585 of these customers, and 1,170 customers did not have interval data at that time. For the customers with interval data available, we used the actual contribution to the system peak hour. For those customers without interval data, we applied the rate class average coincidence factor for September 2003 to their September 2003 billing demand to estimate the contribution to the system peak hour. The actual demands and the estimated demands were then combined to provide results for the entire population of customers with demands over 200 kW.

We did not include agricultural customers in this analysis. We could not find evidence of agricultural customers being served on RTP rates anywhere in literature, so there was nothing upon which to base calculations.

We then split the SCE load for customers with peak demands over 200 kW into two groups, interruptible and firm, in order to estimate the load reduction if the firm customers were moved to the RTP Tariff and the interruptible customers were left on their current interruptible rates. This required making a few additional assumptions. The first was that the interruptible customers would be in the high responding part of each SIC code group. This was based on the fact that they were already curtailing a significant amount of load when called to do so, so they were certainly capable of responding. The interruptible load for some of the SIC code groups was more than the percent of high responders from the Christensen report, so in those cases, we assumed that all of the high responders in the SIC group were interruptible, and part of the moderate responders were interruptible as well.

G. Determining Load Reductions by SIC Group

The Christensen Report did not provide the load reductions by response level either in the aggregate or for individual SIC code groups. Thus, we made one additional assumption. Because the Christensen Report did provide the peak-period elasticity of substitution for each response level within each SIC code group, we made the simplifying assumption that the load reductions in the high and moderate responding groups were proportional to the peak-period elasticity of substitution for the groups. Based on the Georgia Power results, the elasticity in low responding groups is zero. Therefore we assume that there is no load response among this group. As such, there is enough information to allocate the load response by SIC code group to the high and moderate responders. The assumptions used are described in the following three equations:

$$totpctsavings = pctsavings_h \cdot pct_h + pctsavings_m \cdot pct_m + pctsavings_l \cdot pct_l$$
$$\frac{pctsavings_h}{pctsavings_m} = const = \frac{elasticity_h}{elasticity_m}$$
$$pctsavings_l = 0$$

In this formula, "*totpctsavings*" is the total savings for the SIC code group, expressed as a percent, "*pct*" is the percent in the SIC group for each response level, "*const*" is the ratio of the high responder elasticity parameter to the moderate responder elasticity parameter for the SIC group, "*elasticity*" is the elasticity parameter, and "*pctsavings*" is the estimated percent savings for each response level. The subscripts indicate the response level of high, moderate, or low.

Based on these relationships, for each SIC code group, we estimated the percent reduction by response level for the moderate and high responding groups as follows.

$$totpctsavings = const \cdot pctsavings_m \cdot pct_h + pctsavings_m \cdot pct_m + 0 \cdot pct_l$$
$$pctsavings_m = \frac{totpctsavings}{(const \cdot pct_h + pct_m)}$$
$$pctsavings_h = const \cdot pctsavings_m$$

Once the percentage reductions for each SIC group was estimated in this way, we applied those percentage reductions to both the interruptible and firm loads for each SIC group and each response level. We then aggregated the firm loads together and the interruptible loads together, to get total estimated reductions from each group.

Appendix J

Value of Service Loss Description

APPENDIX J

VALUE OF SERVICE LOSS DESCRIPTION

This appendix describes the method we used to estimate the value of the loss of service as described in this volume from all the ratepayer perspective. We used the Standard Practice Manual's (SPM) definition of the all-ratepayer or societal perspective as a measure of overall economic efficiency. The participant and other ratepayer perspectives address the distributional (cost shifting) impacts of a program. The participant perspective can also be helpful in the design of appropriate incentives. The SPM participant perspectives can be expressed as follows in Table J-1:

Table J-1
Standard Practice Manual Perspectives

	Participant Perspective	Other Ratepayer Perspective	All Ratepayer Or Societal Perspective
Benefits	Bill Savings	Resource Cost Savings Operational Savings Metering Charge Revenues	Resource Cost Savings Operational Savings
Costs	Value of Service Loss Metering Charges	Participant Bill Savings AMI Costs DR/DP Admin Costs	AMI Costs DR/DP Admin Costs Value of Service Loss

SCE used this analytical framework for evaluating advanced metering infrastructure investments.

A. Description of the Estimating Method

We have presented the required full and partial deployment final business case analyses set forth using the "all ratepayer" perspective, in order to emphasize economic efficiency. Cases are presented both with and without customer value of service loss to show the effect that this variable has on the analysis results. Consideration of distributional impacts is better addressed in the design of individual pricing demand response programs. It should be noted, however, that because these programs improve the accuracy of price signals which customers receive, any distributional impacts will, in general, reduce the level of cross-subsidy imbedded in current rate designs.

B. Calculation of Value of Loss of Service

Value of service loss can be calculated based on information on customers' response to dynamic pricing derived from the recent pilot studies. Consider a situation where the price of energy in a peak period, increases from a flat-rate of 15 cents to a "real time price" of 25 cents as a result of a dynamic pricing program, and a customer reduces monthly consumption by 100 kWh as a result. We know from this behavior response that the customer values the use of this electricity by a minimum of 15 cents, but less than 25 cents. If the customers' demand response is linear (straight line) then the average value that the customer would have received from the 100 kWh reduced usage is 20 cents, the simple average of the flat rate and real time price. Therefore, we can infer a value of $20 to the foregone consumption (20 cents times 100 kWh).

This approach is consistent with the economics literature addressing time of use and real-time pricing. Acton and Bridger,[71] and Borenstein, Jaske and Rosenfeld,[72] discuss a general societal welfare (benefit) analysis that includes customer value of service impacts. The resultant change in social welfare from a change in pricing strategy from flat rate to time of use or real time rate is shown by the equation:

Δ Societal Benefit = $-\frac{1}{2}\Delta P_1\Delta Q_1 - \frac{1}{2}\Delta P_2\Delta Q_2$

The ΔPs represent the change in prices and the ΔQs represent the change in quantity. This formula is based on two time periods, but generalizes to any number of periods. Because price and quantity change move in opposite directions (an increase in price decreases usage), overall societal benefit is increased by moving to time-of-use or real time pricing. Using

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

[72] Borenstein, Severin, Michael Jaske, and Arthur Rosenfeld. "Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets", University of California Energy Institute, Center for the Study of Energy Markets, October 2002, CSEM Working Paper # 105.

similar nomenclature, where P_1 and P_2 are the time-of-use or real time prices, resource cost savings and value of service loss can be expressed as follows:

□ Resource Cost Savings = $-P_1$ □ Q_1 - P_2 □ Q_2

□ Value of Service Loss = - (P_1 - ½ □ P_1□ □ Q_1) - (P_2 - ½ □ P_2□ □ Q_2)

Given that the objective of time of use or real time pricing is to set rates equal to incremental resource costs associated with consumption, the change in resource costs is given by $P\Delta Q$. Value of service loss is calculated as described above, the average of flat rate and time of use prices times the change in quantity. Subtracting value of service loss from resource cost savings results in the equation for societal benefit shown above.

C. Results of Calculation

The values that result from the calculation method above for Scenarios 4 and 17 are contained in the following table.

Table J-2
Value of Service Analysis Impacts on Demand Response Benefits by Business Case Scenario
($2004 Present Value in Millions)

(1)	(2)	(3)	(4)=(2)+(3)	(5)	(6)	(7)=(5)+(6)-(4)
Scenario	**Value of Service Loss - On-Peak**	**Value of Service Benefit - Off-Peak**	**Net Value of Service Loss Effect**	**DR-1 Benefit**	**DR-2 Benefit**	**Impact = DR-1 + DR-2 - Net Value of Service Effect**
4	$173.5	($30.0)	$143.5	$325.7	$41.0	$223.2
17	$14.8	(4.3)	$10.5	$38.1	$4.8	$32.4

Appendix K

Rate Design and Bill Impact Analysis

APPENDIX K

RATE DESIGN AND BILL IMPACT ANALYSIS

This Appendix describes the processes we could employ to design the experimental/existing CPP rate structures and also describes our approach to, and results of our analysis of, bill impacts expected from these experimental CPP rate structures both in a longer-term, post-AB1X environment (with a variety of usage reductions) and a short-term AB1X-compliant environment, without meter charges. While a wide variety of rate design and billing impacts could be constructed, these two circumstances represent the relevant spectrum of these analyses.

A. Rate Design Process in a Longer Term non-AB1X Environment

1. Domestic (Residential) Rate Design Process

Two sets of residential rates were developed for the AMI business case scenarios to be revenue neutral to the Schedule D energy charges. No changes were made to customer charges. AMI residential rates are based on a six-month summer, and six-month winter season, consistent with the existing SPP experimental rate structures, with the exception of CPP-P, which is an overlay of existing residential tiered rate structure with a four-month summer, and eight-month winter season.

A default two-part D-TOU-2 rate was developed with an on-peak period of 2:00 p.m. to 7:00 p.m., summer and winter weekdays, and all other hours as off-peak. This structure is consistent with existing experimental SPP time periods, and is used as the basis for CPP-F and CPP-V rate design. All rates were constructed to be revenue neutral to Schedule D, assuming no load alterations. Two sets of residential rates were constructed for analytical purposes; the first compliant with AB1X provisions, and the second ignoring the AB1X restrictions. In the non-AB1X compliant rates, the TOU rates along with their CPP components would be more clearly understood by customers since they would understand exactly what the cost of electricity is at any point in time. Designing rates compliant with AB1X restrictions with usage below 130 percent of baseline not subject to CPP or TOU pricing and usage above 130 percent of baseline subject to dynamic pricing would be extremely confusing to customers as it would be difficult for a medium-usage customer to respond to CPP prices if only a pro-rated portion of its above-baseline consumption were subject to the CPP rate. Customers using less than their baseline allowance would never actually be charged the CPP rate, which would eliminate any demand response contributions they could make. During the 12-month period ending April 2004, 74 percent of SCE's residential customers' usage was billed at or below 130 percent of baseline (Tiers 1 and Tier 2). In fact, about 34 percent of residential customers never exceeded their Tier 2 usage levels, meaning a significant portion of customers would be exempt from participating in CPP rates in an AB1X compliant case.

For both sets of rates, the existing D-TOU-2 rate option[73] is used as a basis for TOU rate design. The CPP Event rate was based on the D-TOU-2 summer, on-peak energy rate, plus an approximate $1.1333 per kWh ($85 prescribed avoided peak demand cost divided by 75 hours) adder. Because this CPP peak rate is significantly above the CPP Pilot rate, it established the cap on the CPP rate (even though the reduced number of CPP hours assumed in the CPP-V rate would demand an even higher CPP rate using the same methodology).

The D-TOU-CPP-F rate was modeled after the existing experimental TOU-D-CPP-F rate and assumes 12 Summer Peak days and 3 Winter Peak days at five hours per CPP Event day, for a total of 75 CPP hours annually. The D-TOU-CPP-V rate was also modeled after the existing experimental TOU-D-CPP-F rate

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

using 12 Summer Peak days and three Winter Peak days with only 3 hours per CPP Event between the hours of 2:00 p.m. to 5:00 p.m., for a total of 45 CPP hours annually. The D-TOU-CPP-P rate used the basic tiered residential rate with a CPP adder based on 12 Summer Peak days and 3 Winter Peak days at 5 hours per CPP Event, for a total of 75 CPP hours annually. In all scenarios, the added revenue resulting from high priced CPP events reduces the remaining non-CPP rate levels to maintain revenue neutrality.

2. GS-1 Rate Design Process

All Small Commercial customers' rates for the AMI business case scenarios were developed revenue neutral to the Schedule GS-1 energy charges. No changes were made to customer charges. These rates are based on a four-month summer, and eight-month winter season, consistent with the existing CPP experimental rate structures.

A default two-part GS-1-TOU-2 rate was developed with an on-peak period of noon to 6:00 p.m., summer and winter weekdays, and all other hours as off-peak. This structure is consistent with existing experimental CPP time periods. This default rate was constructed revenue neutral to the existing GS-1 rate, and used the existing GS-1-TOU option as a basis for TOU rate design.

The CPP Event rate was based on the summer on-peak energy rate, plus a $0.9444 per kWh ($85 divided by 90 hours) adder. Similar to the residential rate structures, this CPP event rate is used for GS-1-CPP-F and GS-1-CPP-V, and GS-1-CPP-P rate schedules. GS-1-CPP-F was modeled after the existing experimental GS-1-CPPV rate using 12 Summer Peak days and 3 Winter Peak days at 6 hours per CPP Event, for a total of 90 CPP hours annually.

GS-1-CPP-V was modeled after the existing experimental GS-1-CPPV rate, based on 12 Summer Peak days and 3 Winter Peak days with 3 hours per CPP

Event between the hours of 2:00 p.m. to 5:00 p.m., for a total of 45 CPP hours annually.

GS-1-CPP-P was based on 12 Summer Peak days and three Winter Peak days at 6 hours per CPP Event, for a total of 90 CPP event hours annually. To preserve revenue neutrality, the added revenue resulting from CPP events resulted in a reduction to the otherwise application tariff (OAT) energy charges.

3. GS-2 Rate Design Process

All Medium Commercial customers' rates for the AMI business case scenarios were developed revenue neutral to schedule GS-2 energy charges. No changes were made to the demand or fixed charges. These rates are based on a four-month summer and eight-month winter season, consistent with existing GS-2-CPP rate structure but with the additional allowance of CPP events occurring in the winter season.

The existing (revenue neutral) GS-2-TOU rate option is used as the TOU default, thus no default two-period TOU rate structure was developed for this rate class. The CPP Event rate is based on the GS-2-TOU summer on-peak energy rate, plus a $0.9444 per kWh ($85 divided by 90 hours) adder. The resulting CPP event rate is used for GS-2-CPP-F, GS-2-CPP-V, and GS-2-CPP-P rate schedules.

GS-2-CPP-F is modeled after the existing GS-2-CPP rate, with the exception of adding winter CPP events, and includes 12 Summer Peak days and three Winter Peak days at 6 hours per CPP Event, for a total of 90 CPP hours annually. GS-2-CPP-V is modeled after the existing GS-2-CPP rate using 12 Summer Peak days and 3 Winter Peak days at 3 hours per CPP Event between the hours of 2:00 p.m. to 5:00 p.m., for a total of 45 CPP hours annually. GS-2-CPP-P is based on 12 Summer Peak days and 3 Winter Peak days at 6 hours per CPP Event, for a total of 90 CPP hours annually. The added revenue resulting from CPP events at the CPP rate was offset by a fixed percentage reduction to the other GS-2-TOU energy charges.

Rates used in the business case analysis are:

Table K-1
Rates Structure for Preliminary Analysis

DOMESTIC			
D-TOU-2-Basis		Rate	
Summer	On	0.28026	<<= 6 Month, 2pm-7pm On-Peak
	Off	0.11566	
Winter	On	0.13133	<<= 6 Month, 2pm-7pm On-Peak
	Off	0.1099	
CPP-F		Rate	
CPP Event			
Summer	On	1.41359	<< = 12 Summer Top Peak Days @ 5 hours/Day, 2 pm-7 pm
Winter	On	1.41359	<< = 3 Winter Top Peak Days @ 5 hours/Day, 2 pm-7 pm
Non-CPP Event			
Summer	On	0.22816	
	Off	0.09416	
Winter	On	0.11864	
	Off	0.09928	
CPP-Pure			
CPP Event		Rate	
Summer	On	1.41359	
Winter	On	1.41359	
CPP-V			
CPP Event		Rate	
Summer	On	1.41359	<< = 12 Summer Top Peak Days @ 3 hours/Day, 2 pm-5 pm
Winter	On	1.41359	<< = 3 Winter Top Peak Days @ 3 hours/Day, 2 pm- 5 pm
Non-CPP Event			
Summer	On	0.24991	
	Off	0.10313	
Winter	On	0.12413	
	Off	0.10388	
GS-1			

GS-1-TOU-2-Default		Rate	
Summer	On	0.34731	<<= 4 Month, Noon-6pm On-Peak
	Off	0.10982	
Winter	On	0.11614	<<=8 Month, Noon-6pm On-Peak
	Off	0.10706	

CPP-F			
CPP Event		Rate	
Summer	On	1.28731	<< = 12 Summer Top Peak Days @ 6 hours/Day
Winter	On	1.28731	<< = 3 Winter Top Peak Days @ 6 hours/Day
Non-CPP Event			
Summer	On	0.28254	
	Off	0.08934	
Winter	On	0.10478	
	Off	0.09658	

CPP-Pure		
CPP Event		Rate
Summer	On	1.28731
Winter	On	1.28731

CPP-V			
CPP Event		Rate	
Summer	On	1.28731	<< = 12 Summer Top Peak Days @ 3 hours/Day, 2 pm-5 pm
Winter	On	1.28731	<< = 3 Winter Top Peak Days @ 3 hours/Day, 2 pm - 5pm
Non-CPP Event			
Summer	On	0.31511	
	Off	0.09964	
Winter	On	0.11069	
	Off	0.10203	

GS-2

GS-2-TOU-2-Option/OAT		Rate
Summer	On	0.12796
	Mid	0.09435
	Off	0.08484
Winter	Mid	0.09921
	Off	0.08484

CPP-F		Rate	
CPP Event			
Summer	Noon-6pm	1.06796	<< = 12 Summer Top Peak Days @ 6 hours/Day

Winter	Noon-6pm	1.06796	<< = 3 Winter Top Peak Days @ 6 hours/Day
Non-CPP Event			
Summer	On	0.10463	
	Mid	0.07715	
	Off	0.06937	
Winter	Mid	0.08285	
	Off	0.07085	
CPP-Pure			
CPP Event		Rate	
Summer	On	1.06796	
Winter	On	1.06796	
CPP-V		Rate	
CPP Event			
Summer	Noon-6pm	1.06796	<< = 12 Summer Top Peak Days @ 3 hours/Day
Winter	Noon-6pm	1.06796	<< = 3 Winter Top Peak Days @ 3 hours/Day
Non-CPP Event			
Summer	On	0.11646	
	Mid	0.08587	
	Off	0.07722	
Winter	Mid	0.09127	
	Off	0.07805	

B. Bill Impact Analysis in a Longer-Term Non-AB1X Environment

1. Residential Bill Impacts

Residential bill impacts, which are incorporated into the MMI simulation tool, provided the basis for estimating customer adoption rates for TDRs in certain AMI opt-in scenarios.[74] Additionally, an understanding of bill impacts is necessary to gauge future program success.

As part of the revenue neutrality component in the rate design process, SCE computed average bills for each of the nearly 3,300 customers in its load

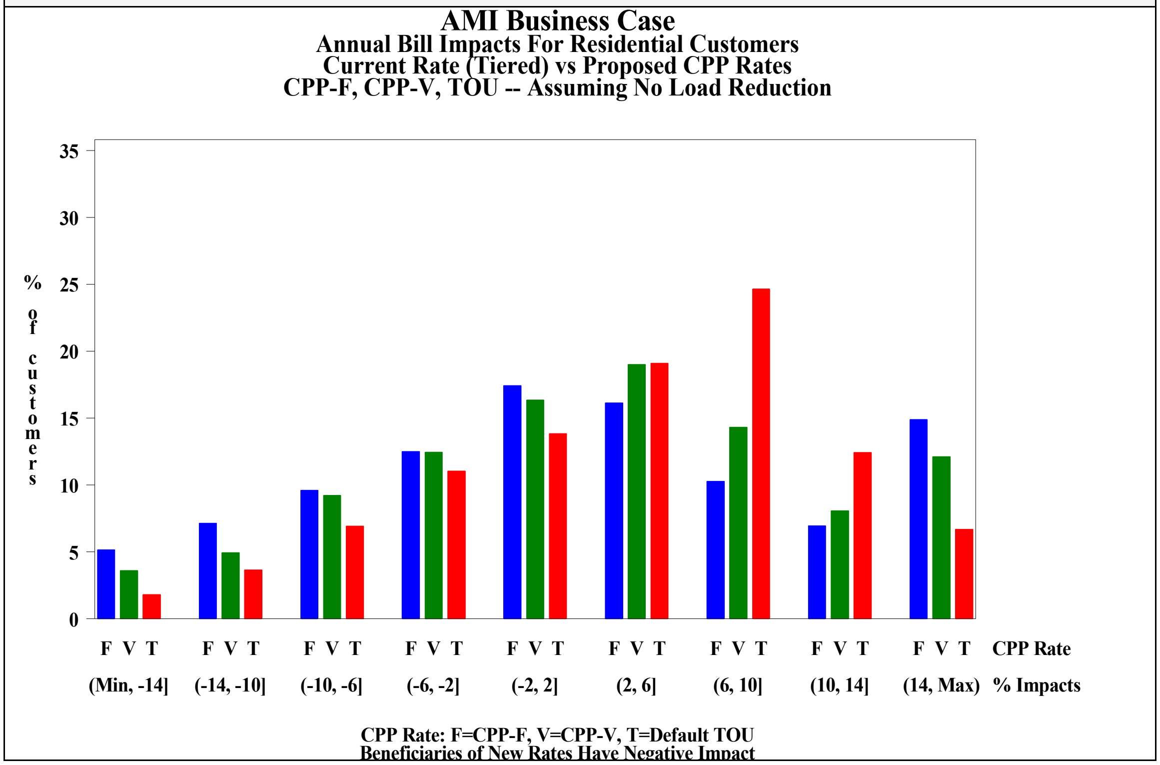
[74] These do not include Scenarios 4 and 17, which were opt-out scenarios.

research residential rate group sample. After applying the relevant sampling weights, rates were scaled to insure that the total bills recovered the same revenue for each customer class. The larger load research sample was used instead of the SPP sample data to gauge these impacts through the use of a larger sample size and to eliminate any impact of participation bias.

Figure K-1 below displays the distribution of bill impacts for the CPP-F, CPP-V, and TOU rates versus the current tiered Domestic rate for the residential customer class assuming no price-induced demand response. Although the revenue-neutral rate design arithmetically centers the distribution around zero, the relatively wide distribution of bill impacts is brought about by a more equitable cost allocation by the CPP rate structures in two ways. First, the elimination of AB1X price cap results in low usage customers experiencing the largest percentage bill increases. Most of the nearly 15 percent of customers experiencing an annual bill increase of at least 14 percent are lower usage customers (see Table K-2). Second, those customers residing in the hotter weather zones using higher amounts of high cost summer on-peak energy also see bills commensurate with their (higher) cost (see Table K-3).

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

Figure K-1
Annual Bill Impacts for Residential Customers – Assuming No Load Reductions



Average Monthly Usage	(Min, -14]	(-14, -10]	(-10, -6]	(-6, -2]	(-2, 2]	(2, 6]	(6, 10]	(10, 14]	(14, Max)	Total
0 - 400 kWh	0.5	1.2	1.	4.	10.1	10.9	6.1	3.0	6.3	44.9
401 - 800 kWh	1.6	4.0	5.	5.	5.	3.	3.2	3.1	7.6	39.1
> 800 kWh	3.1	2.0	2.	2.	2.	1.	1.0	0.8	1.0	16.1

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

Table K-3
Residential Bill Impacts Tiered vs. CPP-F
Percentage Distribution of Accounts by Climate Zone and Percent of Bill Impact

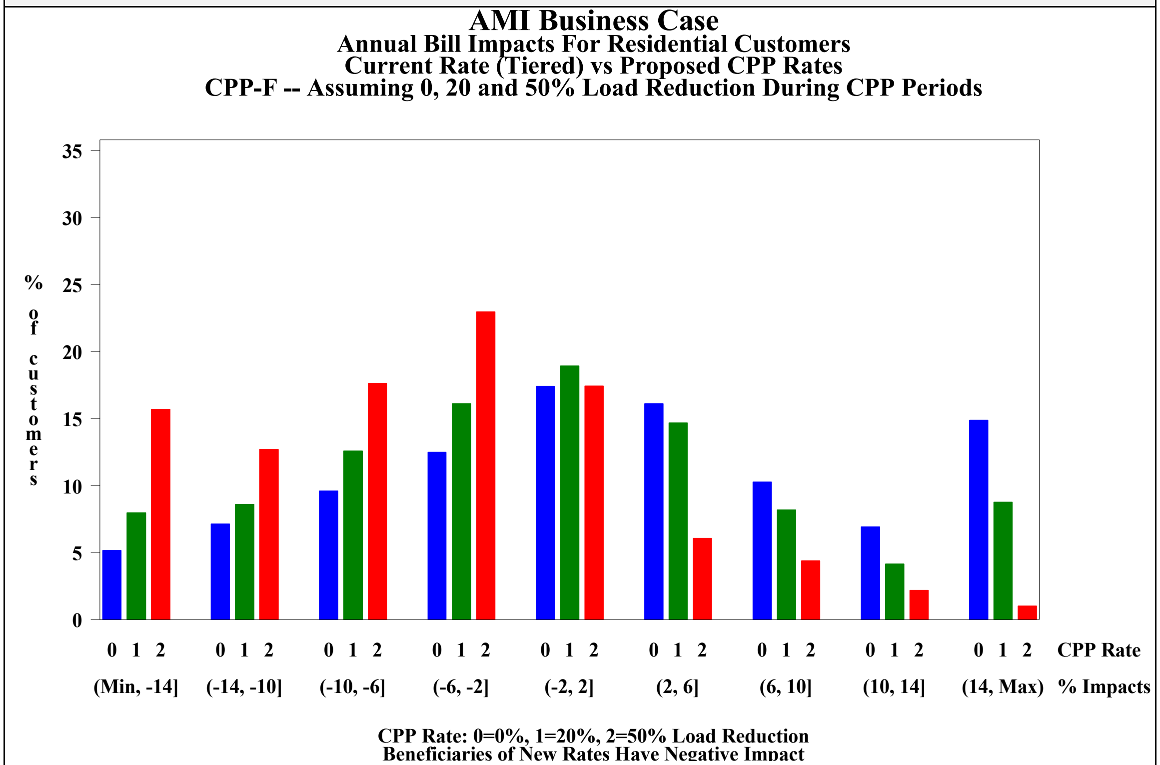
Climate Zone	(Min, -14)	(-14, -10]	(-10, -6]	(-6, -2]	(-2, 2]	(2, 6]	(6, 10]	(10, 14]	(14, Max)	Total
2	3.5	4.7	4.9	6.9	9.1	8.5	4.1	1.4	1.5	44.7
3	1.2	2.2	3.8	4.7	7.1	6.4	5.0	4.8	11.3	46.5
4	0.4	0.2	0.9	0.9	1.2	1.2	1.2	0.7	2.0	8.8
Total	5.2	7.1	9.6	12.5	17.4	16.1	10.3	6.9	14.9	100.0

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

Overall, the TOU and CPP-F rates shift about six to eight percent of the overall revenue burden from the winter season into the summer season, respectively. This type of revenue/cost shift can be accomplished with the existing metering via seasonal energy charges though the peak demand impact of such a seasonal revenue allocation shift would need to be explored. The cost/benefit associated with this option would prove valuable as incremental cost would be negligible and there would almost surely be some demand response benefits.

Figure K-2 below displays three annual bill impact distributions (CPP-F non AB1X compliant versus their tiered OAT rate) for the residential population assuming three different levels of load reduction (0%, 20%, and 50%) for all customers billed on a CPP-F rate. For simplicity, no load shifting was assumed nor were rates re-calibrated to preserve revenue neutrality. Without any load reduction during CPP events, the number of customers experiencing at least a 10 percent annual bill increase is above 22 percent. The most striking component of the bill impact analysis is that the lowest usage customers whose bills would otherwise be frozen by the provisions of AB1-X would see significant bill increases. At the 20 percent load reduction level, typical of the maximum load reductions seen in the SPP pilot, about 13 percent of residential customers still see bill increases of more than 10 percent, while only about 16 percent of our customers would see an annual bill decrease of at least 10 percent.

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



The risk associated with such distributions is that if customers save such small amounts or even see bill increases, while making significant efforts to alter their behavior, they could likely become disillusioned with the program. The cause of this low bill impact despite rather large demand response is that the number of hours designated as CPP periods represents less than one percent of the total hours of energy consumption in the year (75 CPP hours versus 8760 total hours/year). While the CPP rates designed for this application have even a higher ratio to otherwise applicable on-peak rates (at a 6:1 ratio) versus the CPP-Pilot rates, customer bill reductions remain relatively small in spite of significant customer response. It is exactly this type of minimal billing impact despite significant load shifting/reduction that led to the demise of Puget Sound Electric's system-wide TOU deployment. Despite customer response, low bill reductions to those who responded and bill increases associated with the TOU meter cost (at a relatively modest $1/month) led to overall bill *increases* that caused such customer backlash that Puget Sound Energy cancelled the program after less than two years.[75]

Exit interviews of SPP participants will prove valuable at the end of the SPP pilot to gauge ongoing interest and cost savings relative to the effort required to achieve those savings. It is only when customers shed 50 percent of their load during the CPP periods (an extremely unlikely case especially for low usage customers) do significant cost reductions occur (though still not in all cases). In general, the most significant discretionary load capable of providing such a large reduction in load is air-conditioning equipment. It is this overlap that makes us believe that focus on the ALC program is the best alternative for providing cost effective price-induced demand response. Figure K-3 displays similar information using the CPP-V rate design.

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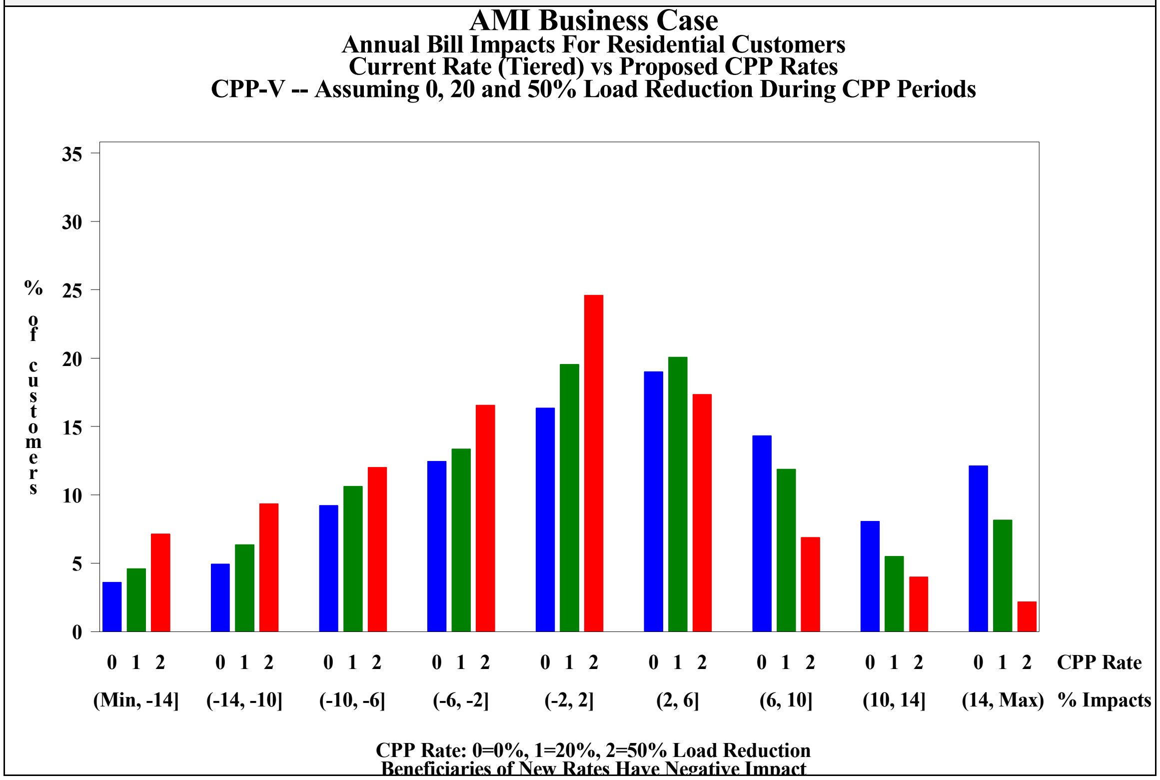
[75] Williamson, Craig, "Primen Perspective: Puget Sound Energy and Residential Time-of-Use Rates – What Happened?" Energy Use Series, Volume 1, Issue 10, December 2002.

Figure K-3
Annual Bill Impacts For Residential Customers – Assuming Load Reductions During CPP-V Periods

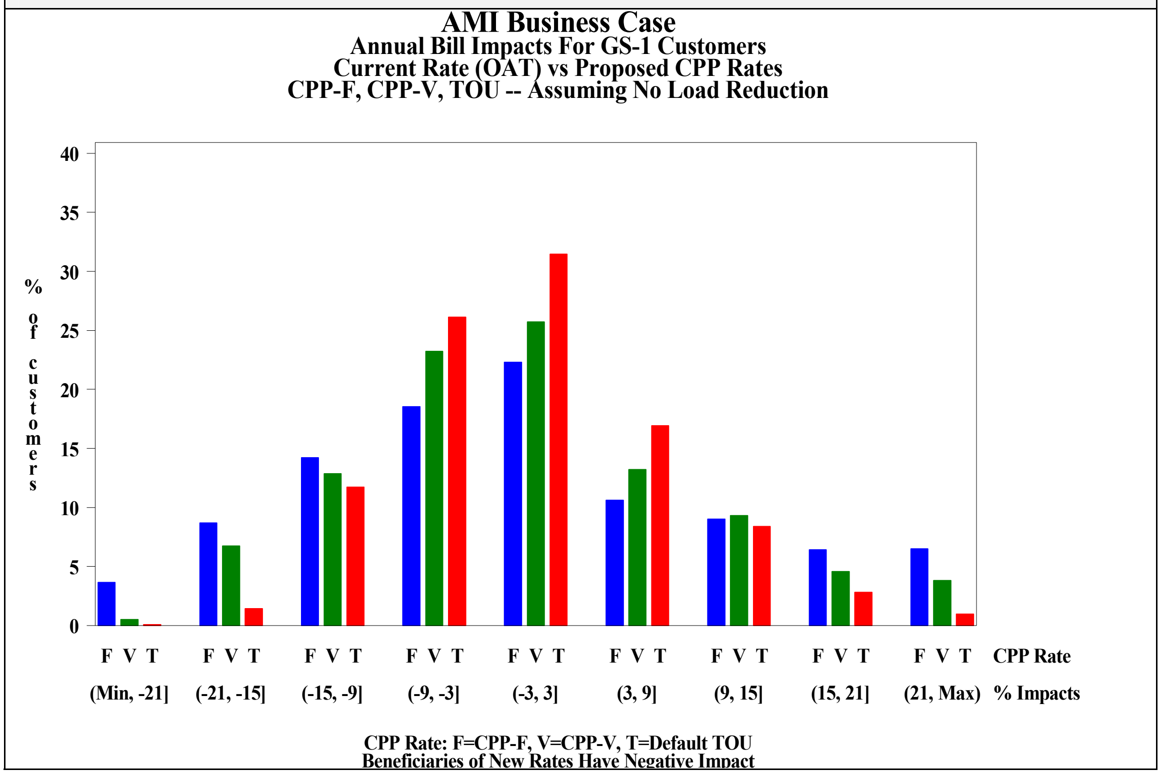


2. Commercial Bill Impacts

As part of the revenue neutrality component in the rate design process, SCE computed average bills for each of the 3,100 and 3,500 customers in its GS-1 and GS-2 load research rate group samples. After applying the relevant sampling weights, rates were scaled to insure that the total bills recovered the same revenue for each customer class. The large load research samples were used instead of the SPP sample data to gauge these impacts due to their larger sample sizes and to eliminate any impacts of participation bias.

Figure K-4 displays bill impact distributions for the small commercial (GS-1) population for the CPP-F, CPP-V, and TOU rate schedules relative to the current GS-1 rate. Again, no load shifting as a result of price response was assumed here. While all three distributions center around zero, under the CPP-F program, about 25 percent of GS-1 customers will experience an annual bill increase of at least nine percent, while about 20 percent of the GS-1 population will experience a bill decrease of at least nine percent due to the more precise cost allocation nature of these rates versus a rate with only seasonal energy charges. The CPP-V and TOU bill impacts have narrower dispersions.

Figure K-4
Annual Bill Impacts for GS-1 Customers –
Assuming No Load Reduction



Figures K-5 and K-6 display bill impact distributions (CPP-F and CPP-V versus their OAT) for the GS-1 populations assuming three different levels of load reduction (0%, 20%, and 50%) for all customers during CPP periods. Load reductions associated with businesses are generally less than residential customers, making the 20 percent and 50 percent cases that much more unlikely (except perhaps in such instances where the utility directly controls the customer's load).

The GS-1 and GS-2 bill impact distributions display similar results to the residential population.

Figure K-5
Annual Bill Impacts for GS-1 Customers –
Assuming Load Reductions During CPP-F Periods

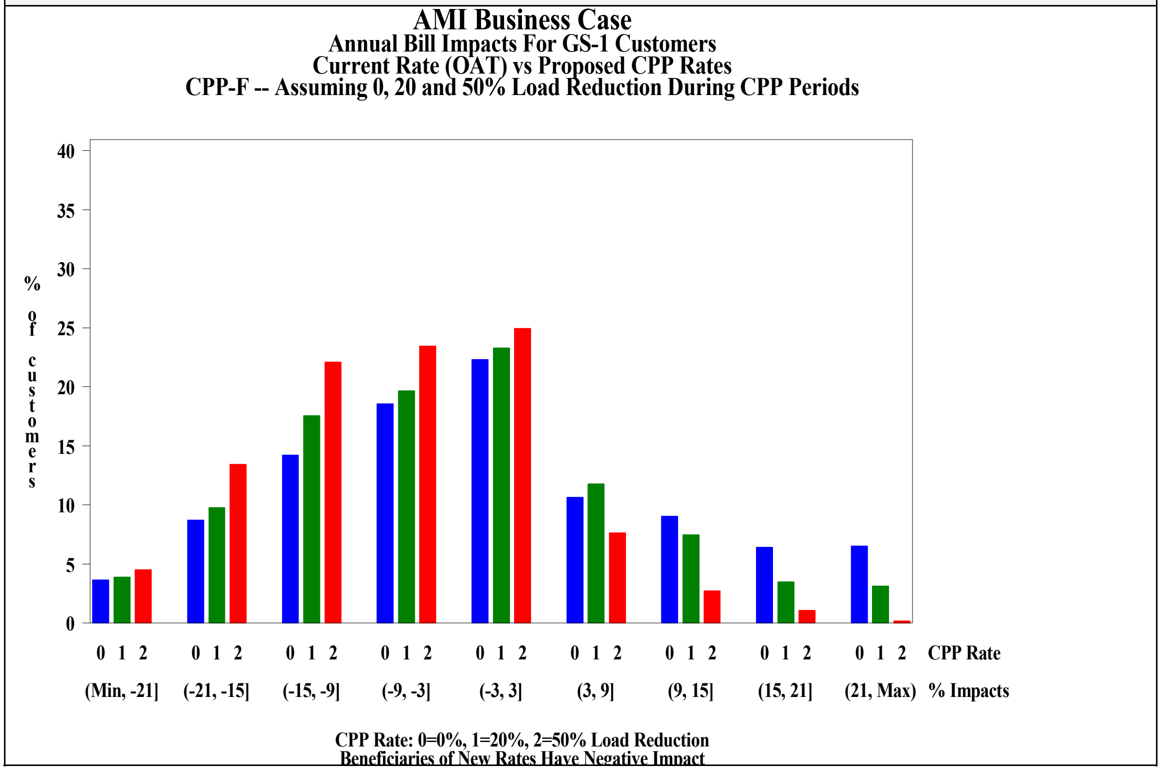


Figure K-6
Annual Bill Impacts for GS-1 Customers – Assuming Load Reductions During CPP-V Periods

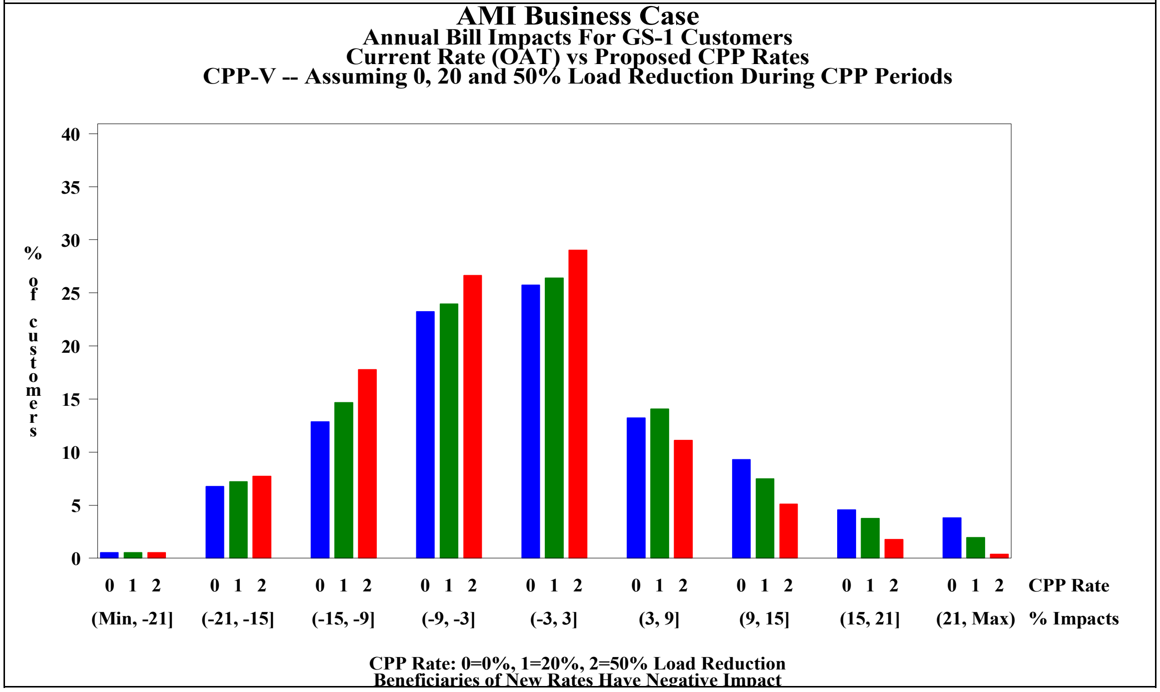


Figure K-7 displays bill impact distributions for the medium commercial (GS-2) population for the CPP-F, CPP-V, CPP-P and TOU rate schedules relative to the current GS-2 rate. Again, no load shifting as a result of price response was assumed here. Compared to the GS-1 bill impact distributions, the GS-2 distributions are somewhat less dispersed as a significant portion of the rate group's total revenue is recovered via demand charges. For these rates, all demand charges were set to equal the existing GS-2 rate constraining the differences between the rates to energy charges. Figures K-8 and K-9 show that the largest bill impacts occur when customers shift 50 percent of their energy consumption out of CPP-F and CPP-V periods. The magnitude of the bill impacts, under the 20 percent reduction scenarios is somewhat subdued as only about 11 percent of these customers realize an annual bill reduction of nine percent or more.

Figure K-7
Annual Bill Impacts for GS-2 Customers –
Assuming No Load Reduction

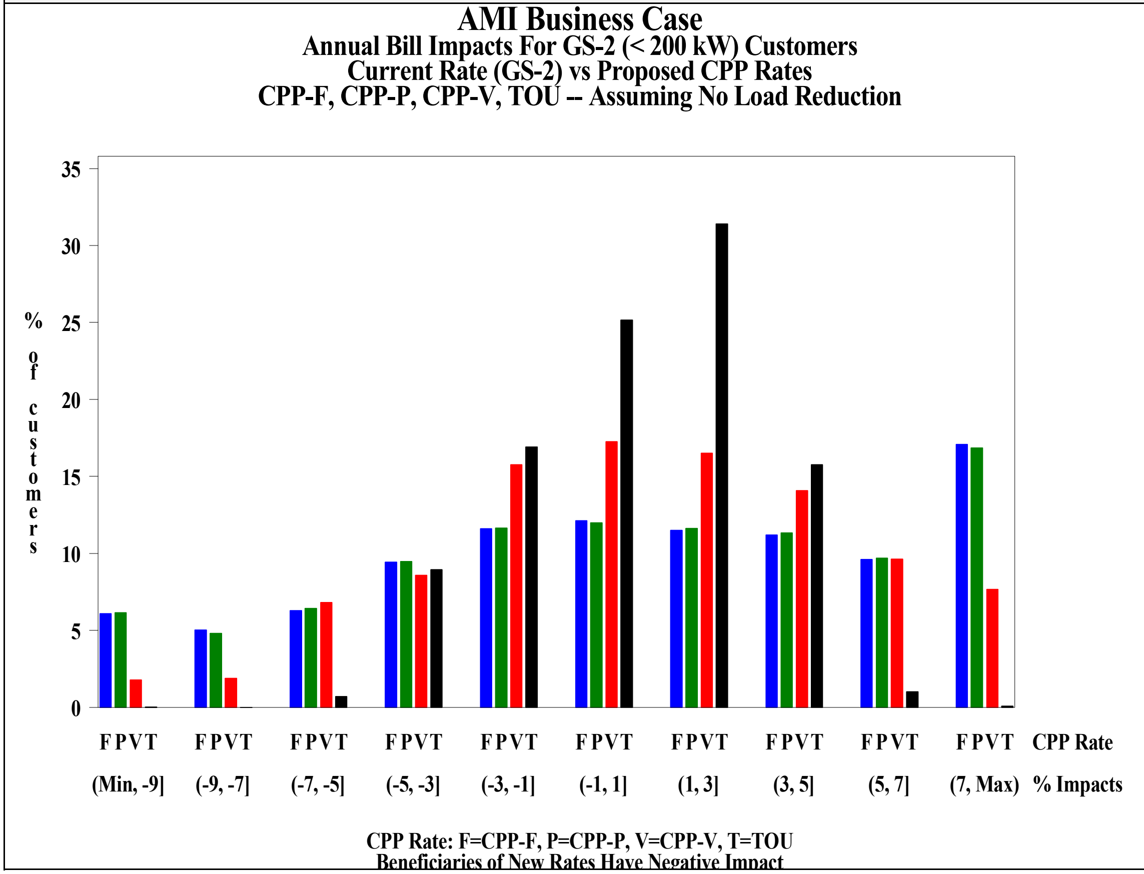


Figure K-8
Annual Bill Impacts for GS-2 Customers –
Assuming Load Reductions During CPP-F Periods

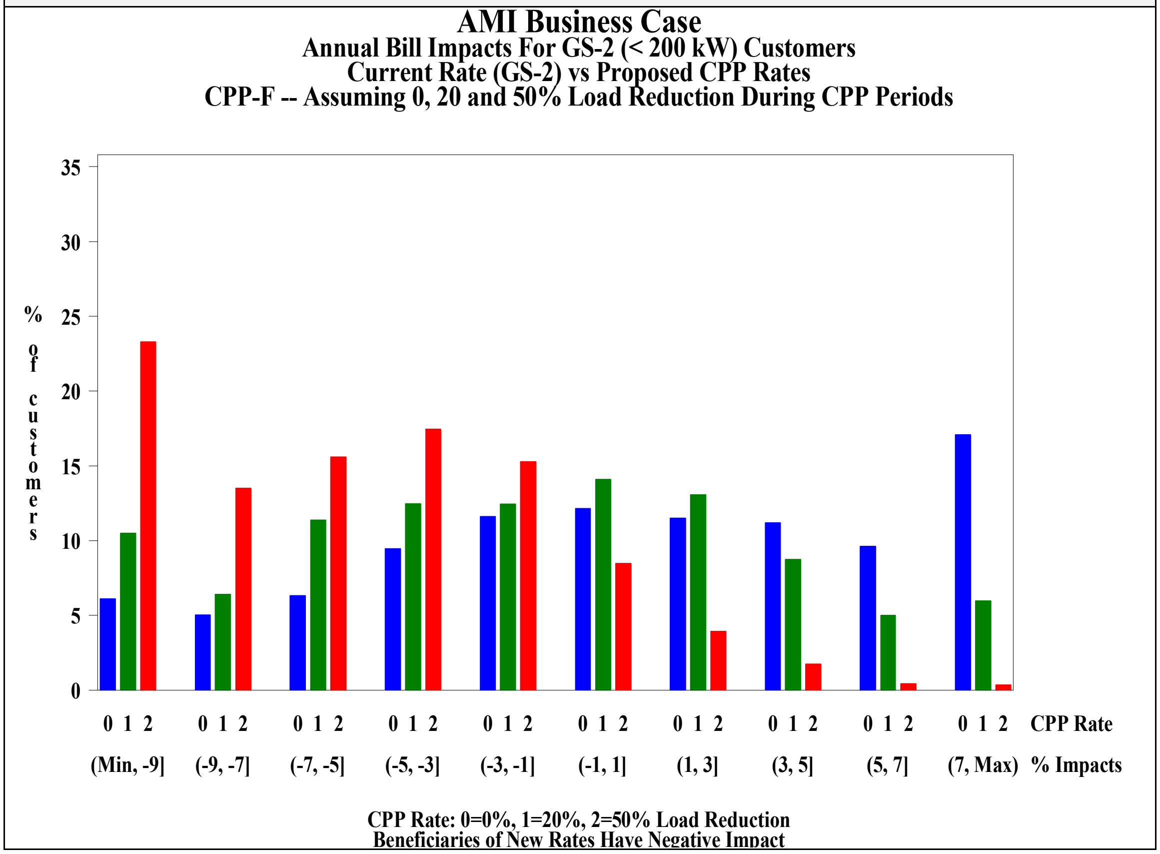
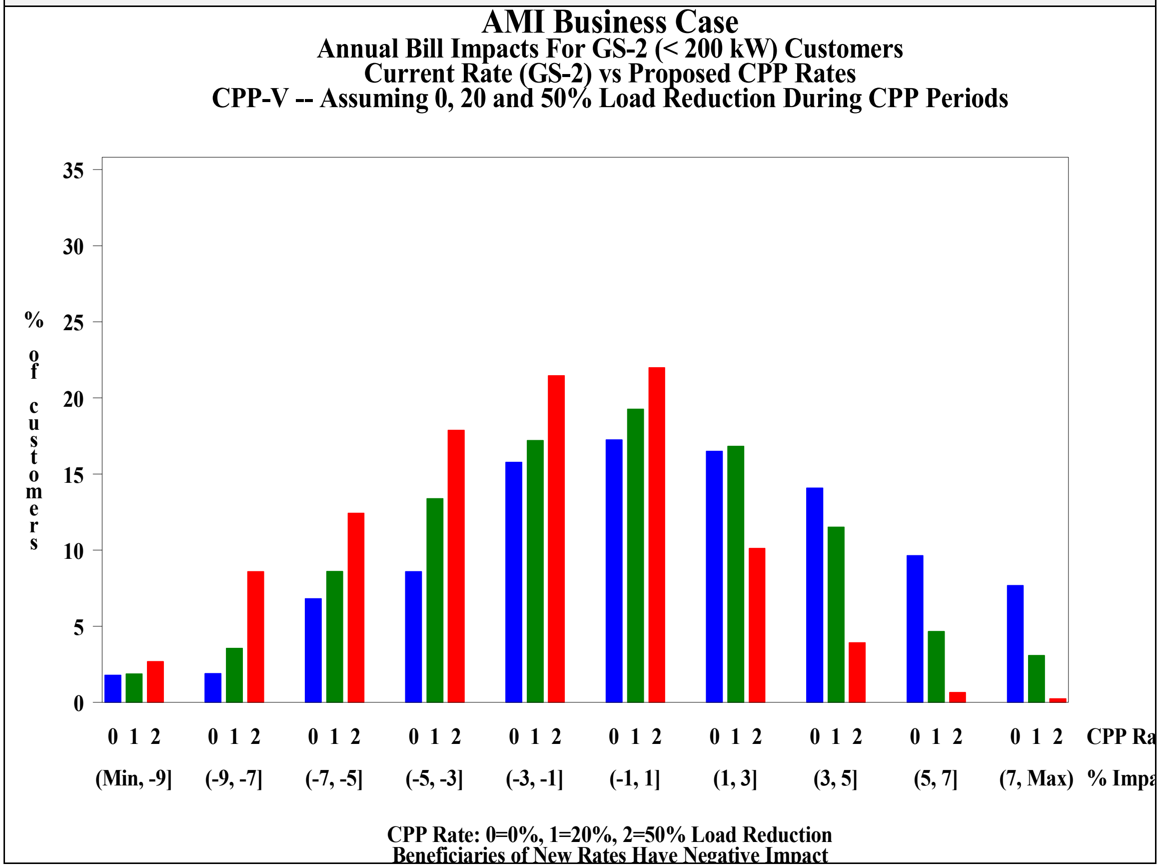


Figure K-9
Annual Bill Impacts for GS-2 Customers –
Assuming Load Reductions During CPP-V Periods



C. Rate Design and Bill Impact Analysis in a Short-Term AB1X Environment

This section presents illustrative revenue allocation and rate design proposals for recovery of SCE's annual AMI revenue requirements under an "operations-only" business case assumption (*i.e.* no change in customer usage patterns) and an AB1X compliant rate design. SCE forecasts positive net-AMI revenue requirements for both the full-deployment and partial deployment cases. AMI infrastructure and O&M related costs authorized for recovery would be credited to the appropriate distribution balancing account for ultimate recovery through distribution rates. SCE presents system and rate group average impacts for both the full- and partial deployment scenarios (Scenarios 4 and 17, respectively) in an AB1X compliant rate design. Analyses provided earlier in this Appendix presented the range of billing impacts in a non-AB1X compliant structure under a wide variety of demand responses. Unlike the bill impacts presented previously in this Appendix, the short-term AB1X environment discussed below assumes no demand response under a purely operational scenario and simply includes the rate effects of capital recovery and net operational impacts as part of a distribution rate adder.

1. Allocation of Net-AMI Revenue Requirement

Excluding any benefits from energy procurement due to assumed unchanging customer usage patterns, the cumulative net AMI-related revenue requirements for the full- and partial deployment Scenarios 4 and 17 without procurement benefits are forecasted at $1.329 billion and $173 million, respectively. For illustrative purposes, SCE proposes to allocate a levelized annual revenue requirement for both scenarios to rate groups based on distribution revenues as determined in SCE's 2003 GRC. The allocated net-AMI revenue requirement for Scenarios 4 and 17 of $174.0 million and $22.7 million, on a levelized annual basis, represents about 1.7 percent and 0.2 percent of SCE's total revenue requirement. However, because distribution revenue requirement is allocated to rate groups based on distribution marginal cost, the percentage impact to individual rate groups will vary. In addition, the impact of distribution rate increases on residential customers will fall disproportionately to higher usage customers as a result of restrictions under AB1X. Monthly customer charges and Tier 1 and Tier 2 energy charges for up to 130 percent of baseline consumption are capped at levels in effect as of February 2001.

2. Distribution Rate Design and Average Bill Impacts

SCE proposes to adjust the distribution component of retail Delivery charges based on the system average percentage change (SAPC) basis in Distribution revenue resulting under each of the scenarios being analyzed. This approach is consistent with SCE's methodology for incorporating Distribution revenue changes in recent Commission decisions in phase 1 of SCE's 2003 GRC and 2004-2005 ERRA. Because current distribution rates reflect the revenue allocations included in the Settlement Agreement in phase 2 of SCE's 2003 GRC, adopted by the Commission in Decision (D.) 05-03-022, scaling distribution rates on a SAPC basis maintains the authorized level of distribution revenue allocation. Tables K-4 through K-7 show the illustrative rate group total revenue requirement and average rate percentage impacts of the distribution revenue requirement increases under SCE's full- and partial AMI deployment scenarios, for bundled service and Direct Access (DA) customers. Although bundled service and DA customers pay the same charges for Delivery service, the percentage impact to class average DA rates is greater, because distribution makes up a larger percentage of the DA customer bill.

Table K-4
Illustrative Bill Impact Analysis
Domestic Service – AB1X Restrictions

	Monthly Usage Level - Summer kWh					
	200	500	750	1000	1500	2000
Current Rate	$ 24.62	$ 64.48	$ 108.15	$ 154.94	$ 248.44	$ 342.12
Scenario #4	$ 24.62	$ 64.91	$ 110.97	$ 160.16	$ 258.42	$ 356.90
Scenario #17	$ 24.62	$ 64.53	$ 108.52	$ 155.62	$ 249.74	$ 344.06
Total Summer Bill Impact						
Scenario #4	$ -	$ 1.72	$ 11.29	$ 20.86	$ 39.94	$ 59.12
Scenario #17	$ -	$ 0.23	$ 1.48	$ 2.73	$ 5.23	$ 7.74
# Monthly Bills	14.6%	39.1%	18.7%	10.6%	10.6%	6.4%

	Monthly Usage Level - Winter kWh					
	200	500	750	1000	1500	2000
Current Rate	$ 24.62	$ 67.66	$ 112.90	$ 159.69	$ 253.28	$ 346.87
Scenario #4	$ 24.62	$ 68.71	$ 116.34	$ 165.53	$ 263.90	$ 362.27
Scenario #17	$ 24.62	$ 67.80	$ 113.35	$ 160.45	$ 254.67	$ 348.89
Total Winter Bill Impact						
Scenario #4	$ -	$ 8.42	$ 27.55	$ 46.69	$ 84.95	$ 123.22
Scenario #17	$ -	$ 1.10	$ 3.61	$ 6.11	$ 11.12	$ 16.13
# Monthly Bills	17.2%	47.4%	20.7%	8.3%	5.0%	1.4%

Total Annual Bill Impact						
Scenario #4	$ -	$ 10.14	$ 38.84	$ 67.54	$ 124.89	$ 182.34
Scenario #17	$ -	$ 1.33	$ 5.09	$ 8.84	$ 16.35	$ 23.88

Note:
Current rates based on proposed D.05-03-022 rates adjusted for authorized 2005 ERRA and DWR revenue requirement changes.

Scenario #4 AMI net revenue requirement rate equals $0.00275 per kWh if applied to all Domestic sales, adjusted to $0.00957 per kWh to reflect upper tier sales only.

Scenario #17 AMI net revenue requirement rate equals $0.00036 per kWh if applied to all Domestic sales, adjusted to $0.00125 per kWh to reflect upper tier sales only.

Table K-5
2005 Revenue Requirement–Settlement (Adjusted for 2005 ERRA and DWR)
Estimates of Sales and Proposed Rate Revenue

		Scenario 4											
Line No.	Rate Schedule By Customer Group	Bundled MWh (M)	Bundled Delivery ($M)	Net AMI Rev Req ($M)	Bundled Generation ($M)	Bundled Total ($M)	Bundled Impact	DA MWh (M)	DA Delivery ($M)	Net AMI Rev Req ($M)	DA Generation ($M)	DA Total ($M)	DA Impact
1	Domestic												
2	D	20,135,434.6	1,451,218.2	55,779.8	1,382,582.0	2,889,580.1	1.968%	169,869.8	11,934.6	470.6	3,806.7	16,211.8	2.989%
3	D-CARE	4,768,928.4	154,403.3	13,290.9	292,355.4	460,049.6	2.975%	25,889.3	774.4	72.2	0.0	846.5	9.317%
4	D-APS	1,003,886.0	54,375.9	2,532.9	75,140.0	132,048.8	1.956%	17,007.9	946.9	42.9	381.1	1,371.0	3.231%
5	DE	98,588.6	3,519.9	74.0	6,910.5	10,504.4	0.709%	40.9	1.9	0.0	0.9	2.8	1.090%
6	DM	128,705.6	9,186.8	351.3	8,752.4	18,290.4	1.958%	4,411.8	307.8	12.0	98.9	418.7	2.961%
7	DMS-1	33,007.4	2,389.9	92.0	2,176.0	4,658.0	2.015%	305.1	21.3	0.9	6.8	29.0	3.025%
8	DMS-2	450,209.4	26,582.8	1,180.0	31,749.9	59,512.7	2.023%	10,875.4	640.7	28.5	243.7	913.0	3.223%
9		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
10	Group Total	26,618,760.1	1,701,676.9	73,300.9	1,799,666.2	3,574,644.0	2.094%	228,400.1	14,627.6	627.1	4,538.2	19,792.9	3.272%
11													
12	Lighting-SM Med Power												
13	GS-1	4,711,671.5	304,861.6	10,666.7	407,516.8	723,045.1	1.497%	68,342.3	4,386.7	154.7	1,531.6	6,073.0	2.614%
14	GS-2	20,815,376.6	1,122,008.3	42,480.7	1,742,809.3	2,907,298.3	1.483%	3,195,515.9	126,757.3	6,521.5	71,611.5	204,890.3	3.288%
15	GS-2-S	0.0	776.6	40.8	253.6	1,071.0	3.957%	0.0	1.0	0.0	0.0	1.0	0.000%
16	TC-1	83,701.5	3,791.2	152.1	5,434.6	9,377.8	1.648%	1,428.5	71.2	2.6	32.0	105.8	2.515%
17	TOU-GS-2	698,972.9	25,207.9	868.7	43,255.6	69,332.1	1.269%	90,170.7	2,823.7	112.1	2,020.7	4,956.5	2.313%
18		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
19	Group Total	26,309,722.6	1,456,645.6	54,208.9	2,199,269.9	3,710,124.4	1.483%	3,355,457.4	134,039.9	6,790.9	75,195.8	216,026.6	3.246%
20													
21	Large Power												
22	TOU-8-SEC	7,350,487.5	298,025.8	11,323.0	526,712.6	836,061.4	1.373%	2,033,165.9	77,681.2	3,132.0	45,563.2	126,376.4	2.541%
23	TOU-8-PRI	4,793,763.8	163,454.8	6,028.6	324,062.4	493,545.8	1.237%	1,675,413.6	52,660.0	2,107.0	37,546.0	92,313.1	2.336%
24	TOU-8-SUB	3,011,507.2	30,870.0	901.5	175,193.7	206,965.3	0.438%	4,155,215.8	58,491.6	1,243.9	93,118.4	152,853.9	0.820%
25	TOU-8-S-SEC	0.0	784.5	41.2	256.2	1,081.8	3.957%	0.0	0.0	0.0	0.0	0.0	0.000%
26	TOU-8-S-PRI	0.0	4,996.9	266.1	1,699.0	6,962.0	3.974%	0.0	0.2	0.0	0.0	0.2	0.000%
27	TOU-8-S-SUB	0.0	4,402.7	164.7	1,439.4	6,006.8	2.819%	0.0	0.1	0.0	0.0	0.1	0.000%
28		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
29	Group Total	15,155,758.4	502,534.7	18,725.2	1,029,363.2	1,550,623.1	1.222%	7,863,795.3	188,833.1	6,482.9	176,227.7	371,543.7	1.776%
30													
31	Agricultural & Pumping												
32	PA-1	414,290.5	24,491.5	1,044.1	37,680.9	63,216.5	1.679%	3,687.6	151.5	9.3	82.6	243.4	3.970%
33	PA-2	351,018.8	13,826.8	544.1	23,989.4	38,360.3	1.439%	8,830.7	283.6	13.7	197.9	495.1	2.843%
34	TOU-AG	1,192,100.3	45,425.4	1,681.5	45,943.7	93,050.6	1.840%	69,156.9	2,504.2	97.6	1,549.8	4,151.5	2.406%
35	TOU-PA-5	934,617.8	29,913.6	1,055.5	40,140.4	71,109.5	1.507%	6,914.7	227.8	7.8	155.0	390.6	2.040%
36		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
37	Group Total	2,892,027.4	113,657.3	4,325.2	147,754.4	265,736.9	1.655%	88,589.8	3,167.0	128.3	1,985.3	5,280.6	2.491%
38													
39	Street & Area Lighting												
40	LS-1	434,868.8	51,478.8	159.3	18,802.8	70,440.9	0.227%	4,448.7	146.7	1.6	99.7	248.0	0.661%
41	LS-2	97,687.3	4,175.6	35.8	4,223.8	8,435.2	0.426%	1,648.9	155.7	0.6	37.0	193.2	0.314%
42	LS-3	78,977.1	1,890.8	55.5	3,414.8	5,361.1	1.046%	9,106.2	208.9	6.4	204.1	419.4	1.550%
43	DWL	2,395.5	407.5	0.9	103.6	511.9	0.172%	15.7	2.9	0.0	0.4	3.3	0.175%
44	OL-1	13,383.7	1,558.2	4.9	578.7	2,141.8	0.229%	77.9	7.3	0.0	1.7	9.1	0.315%
45		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
46	Group Total	627,312.5	59,510.8	256.4	27,123.7	86,890.9	0.296%	15,297.4	521.5	8.7	342.8	873.0	1.003%
47													
48													
49	Total 5 Cust Gps.	71,603,580.9	3,834,025.3	150,816.6	5,203,177.3	9,188,019.2	1.669%	11,551,540.0	341,189.2	14,037.9	258,289.7	613,516.8	2.342%
50		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
51	CPUC Juris. Other												
52													
53	Spec. Con. Sub.	808,414.0	6,160.1	41.3	54,163.7	60,365.2	0.069%	0.0	0.0	0.0	0.0	0.0	0.000%
54		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
55	Group Total	808,414.0	6,160.1	41.3	54,163.7	60,365.2	0.069%	0.0	0.0	0.0	0.0	0.0	0.000%
56													
57		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
58	Grand Total	72,411,994.9	3,840,185.4	150,858.0	5,257,341.1	9,248,384.4	1.658%	11,551,540.0	341,189.2	14,037.9	258,289.7	613,516.8	2.342%

Table K-6
2005 Revenue Requirement-Settlement (Adjusted for 2005 ERRA and DWR)
Estimates of Sales and Proposed Rate Revenue

		Scenario 4											
Line No.	Rate Schedule By Customer Group	Bundled MWh (M)	Bundled Delivery ($M)	Net AMI Rev Req ($M)	Bundled Generation ($M)	Bundled Total ($M)	Bundled Impact	DA MWh (M)	DA Delivery ($M)	Net AMI Rev Req ($M)	DA Generation ($M)	DA Total ($M)	DA Impact
1	Domestic												
2	D	20,135,434.6	0.07207	0.00277	0.06866	0.14351	1.968%	169,869.8	0.07026	0.00277	0.02241	0.09544	2.989%
3	D-CARE	4,768,928.4	0.03238	0.00279	0.06130	0.09647	2.975%	25,889.3	0.02991	0.00279	0.00000	0.03270	9.317%
4	D-APS	1,003,886.0	0.05417	0.00252	0.07485	0.13154	1.956%	17,007.9	0.05568	0.00252	0.02241	0.08061	3.231%
5	DE	98,588.6	0.03570	0.00075	0.07009	0.10655	0.709%	40.9	0.04642	0.00075	0.02241	0.06958	1.090%
6	DM	128,705.6	0.07138	0.00273	0.06800	0.14211	1.958%	4,411.8	0.06977	0.00273	0.02241	0.09491	2.961%
7	DMS-1	33,007.4	0.07241	0.00279	0.06592	0.14112	2.015%	305.1	0.06975	0.00279	0.02241	0.09495	3.025%
8	DMS-2	450,209.4	0.05905	0.00262	0.07052	0.13219	2.023%	10,875.4	0.05892	0.00262	0.02241	0.08395	3.223%
9		----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
10	Group Total	26,618,760.1	0.06393	0.00275	0.06761	0.13429	2.094%	228,400.1	0.06404	0.00275	0.01987	0.08666	3.272%
11													
12	Lighting-SM Med Power												
13	GS-1	4,711,671.5	0.06470	0.00226	0.08649	0.15346	1.497%	68,342.3	0.06419	0.00226	0.02241	0.08886	2.614%
14	GS-2	20,815,376.6	0.05390	0.00204	0.08373	0.13967	1.483%	3,195,515.9	0.03967	0.00204	0.02241	0.06412	3.288%
15	GS-2-S	0.0						0.0					
16	TC-1	83,701.5	0.04529	0.00182	0.06493	0.11204	1.648%	1,428.5	0.04984	0.00182	0.02241	0.07407	2.515%
17	TOU-GS-2	698,972.9	0.03606	0.00124	0.06188	0.09919	1.269%	90,170.7	0.03132	0.00124	0.02241	0.05497	2.313%
18		----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
19	Group Total	26,309,722.6	0.05537	0.00206	0.08359	0.14102	1.483%	3,355,457.4	0.03995	0.00202	0.02241	0.06438	3.246%
20													
21	Large Power												
22	TOU-8-SEC	7,350,487.5	0.04055	0.00154	0.07166	0.11374	1.373%	2,033,165.9	0.03821	0.00154	0.02241	0.06216	2.541%
23	TOU-8-PRI	4,793,763.8	0.03410	0.00126	0.06760	0.10296	1.237%	1,675,413.6	0.03143	0.00126	0.02241	0.05510	2.336%
24	TOU-8-SUB	3,011,507.2	0.01025	0.00030	0.05817	0.06872	0.438%	4,155,215.8	0.01408	0.00030	0.02241	0.03679	0.820%
25	TOU-8-S-SEC	0.0						0.0					
26	TOU-8-S-PRI	0.0						0.0					
27	TOU-8-S-SUB	0.0						0.0					
28		----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
29	Group Total	15,155,758.4	0.03316	0.00124	0.06792	0.10231	1.222%	7,863,795.3	0.02401	0.00082	0.02241	0.04725	1.776%
30													
31	Agricultural & Pumping												
32	PA-1	414,290.5	0.05912	0.00252	0.09095	0.15259	1.679%	3,687.6	0.04107	0.00252	0.02241	0.06600	3.970%
33	PA-2	351,018.8	0.03939	0.00155	0.06834	0.10928	1.439%	8,830.7	0.03211	0.00155	0.02241	0.05607	2.843%
34	TOU-AG	1,192,100.3	0.03811	0.00141	0.03854	0.07806	1.840%	69,156.9	0.03621	0.00141	0.02241	0.06003	2.406%
35	TOU-PA-5	934,617.8	0.03201	0.00113	0.04295	0.07608	1.507%	6,914.7	0.03295	0.00113	0.02241	0.05649	2.040%
36		----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
37	Group Total	2,892,027.4	0.03930	0.00150	0.05109	0.09189	1.655%	88,589.8	0.03575	0.00145	0.02241	0.05961	2.491%
38													
39	Street & Area Lighting												
40	LS-1	434,868.8	0.11838	0.00037	0.04324	0.16198	0.227%	4,448.7	0.03297	0.00037	0.02241	0.05575	0.661%
41	LS-2	97,687.3	0.04274	0.00037	0.04324	0.08635	0.426%	1,648.9	0.09441	0.00037	0.02241	0.11718	0.314%
42	LS-3	78,977.1	0.02394	0.00070	0.04324	0.06788	1.046%	9,106.2	0.02295	0.00070	0.02241	0.04606	1.550%
43	DWL	2,395.5	0.17010	0.00037	0.04324	0.21370	0.172%	15.7	0.18660	0.00037	0.02241	0.20937	0.175%
44	OL-1	13,383.7	0.11642	0.00037	0.04324	0.16003	0.229%	77.9	0.09380	0.00037	0.02241	0.11658	0.315%
45		----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
46	Group Total	627,312.5	0.09487	0.00041	0.04324	0.13851	0.296%	15,297.4	0.03409	0.00057	0.02241	0.05707	1.003%
47													
48													
49	Total 5 Cust Gps.	71,603,580.9	0.05355	0.00211	0.07267	0.12832	1.669%	11,551,540.0	0.02954	0.00122	0.02236	0.05311	2.342%
50		----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
51	CPUC Juris. Other												
52													
53	Spec. Con. Sub.	808,414.0	0.00762	0.00005	0.06700	0.07467	0.069%	0.0					
54		----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
55	Group Total	808,414.0	0.00762	0.00005	0.06700	0.07467	0.069%	0.0					
56													
57		----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------	----------------
58	Grand Total	72,411,994.9	0.05303	0.00208	0.07260	0.12772	1.658%	11,551,540.0	0.02954	0.00122	0.02236	0.05311	2.342%

Table K-7
2005 Revenue Requirement-Settlement (Adjusted for 2005 ERRA and DWR)
Estimates of Sales and Proposed Rate Revenue

		Scenario 17											
Line No.	Rate Schedule By Customer Group	Bundled MWh (M)	Bundled Delivery ($M)	Net AMI Rev Req ($M)	Bundled Generation ($M)	Bundled Total ($M)	Bundled Impact	DA MWh (M)	DA Delivery ($M)	Net AMI Rev Req ($M)	DA Generation ($M)	DA Total ($M)	DA Impact
1	Domestic												
2	D	20,135,434.6	1,451,218.2	7,303.9	1,382,582.0	2,841,104.2	0.258%	169,869.8	11,934.6	61.6	3,806.7	15,802.9	0.391%
3	D-CARE	4,768,928.4	154,403.3	1,740.3	292,355.4	448,499.0	0.390%	25,889.3	774.4	9.4	0.0	783.8	1.220%
4	D-APS	1,003,886.0	54,375.9	331.7	75,140.0	129,847.6	0.256%	17,007.9	946.9	5.6	381.1	1,333.7	0.423%
5	DE	98,588.6	3,519.9	9.7	6,910.5	10,440.1	0.093%	40.9	1.9	0.0	0.9	2.8	0.143%
6	DM	128,705.6	9,186.8	46.0	8,752.4	17,985.2	0.256%	4,411.8	307.8	1.6	98.9	408.3	0.388%
7	DMS-1	33,007.4	2,389.9	12.0	2,176.0	4,578.0	0.264%	305.1	21.3	0.1	6.8	28.2	0.396%
8	DMS-2	450,209.4	26,582.8	154.5	31,749.9	58,487.2	0.265%	10,875.4	640.7	3.7	243.7	888.2	0.422%
9		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
10	Group Total	26,618,760.1	1,701,676.9	9,598.2	1,799,666.2	3,510,941.2	0.274%	228,400.1	14,627.6	82.1	4,538.2	19,247.9	0.428%
11													
12	Lighting-SM Med Power												
13	GS-1	4,711,671.5	304,861.6	1,396.7	407,516.8	713,775.2	0.196%	68,342.3	4,386.7	20.3	1,531.6	5,938.5	0.342%
14	GS-2	20,815,376.6	1,122,008.3	5,562.5	1,742,809.3	2,870,380.1	0.194%	3,195,515.9	126,757.3	853.9	71,611.5	199,222.7	0.430%
15	GS-2-S	0.0	776.6	5.3	253.6	1,035.6	0.518%	0.0	1.0	0.0	0.0	1.0	0.000%
16	TC-1	83,701.5	3,791.2	19.9	5,434.6	9,245.7	0.216%	1,428.5	71.2	0.3	32.0	103.6	0.329%
17	TOU-GS-2	698,972.9	25,207.9	113.7	43,255.6	68,577.2	0.166%	90,170.7	2,823.7	14.7	2,020.7	4,859.1	0.303%
18		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
19	Group Total	26,309,722.6	1,456,645.6	7,098.2	2,199,269.9	3,663,013.7	0.194%	3,355,457.4	134,039.9	889.2	75,195.8	210,124.9	0.425%
20													
21	Large Power												
22	TOU-8-SEC	7,350,487.5	298,025.8	1,482.7	526,712.6	826,221.1	0.180%	2,033,165.9	77,681.2	410.1	45,563.2	123,654.5	0.333%
23	TOU-8-PRI	4,793,763.8	163,454.8	789.4	324,062.4	488,306.5	0.162%	1,675,413.6	52,660.0	275.9	37,546.0	90,481.9	0.306%
24	TOU-8-SUB	3,011,507.2	30,870.0	118.0	175,193.7	206,181.8	0.057%	4,155,215.8	58,491.6	162.9	93,118.4	151,772.8	0.107%
25	TOU-8-S-SEC	0.0	784.5	5.4	256.2	1,046.1	0.518%	0.0	0.0	0.0	0.0	0.0	0.000%
26	TOU-8-S-PRI	0.0	4,996.9	34.8	1,699.0	6,730.7	0.520%	0.0	0.2	0.0	0.0	0.2	0.000%
27	TOU-8-S-SUB	0.0	4,402.7	21.6	1,439.4	5,863.6	0.369%	0.0	0.1	0.0	0.0	0.1	0.000%
28		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
29	Group Total	15,155,758.4	502,534.7	2,451.9	1,029,363.2	1,534,349.8	0.160%	7,863,795.3	188,833.1	848.9	176,227.7	365,909.6	0.233%
30													
31	Agricultural & Pumping												
32	PA-1	414,290.5	24,491.5	136.7	37,680.9	62,309.1	0.220%	3,687.6	151.5	1.2	82.6	235.3	0.520%
33	PA-2	351,018.8	13,826.8	71.2	23,989.4	37,887.5	0.188%	8,830.7	283.6	1.8	197.9	483.2	0.372%
34	TOU-AG	1,192,100.3	45,425.4	220.2	45,943.7	91,589.2	0.241%	69,156.9	2,504.2	12.8	1,549.8	4,066.8	0.315%
35	TOU-PA-5	934,617.8	29,913.6	138.2	40,140.4	70,192.2	0.197%	6,914.7	227.8	1.0	155.0	383.8	0.267%
36		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
37	Group Total	2,892,027.4	113,657.3	566.4	147,754.4	261,978.0	0.217%	88,589.8	3,167.0	16.8	1,985.3	5,169.1	0.326%
38													
39	Street & Area Lighting												
40	LS-1	434,868.8	51,478.8	20.9	18,802.8	70,302.4	0.030%	4,448.7	146.7	0.2	99.7	246.6	0.087%
41	LS-2	97,687.3	4,175.6	4.7	4,223.8	8,404.1	0.056%	1,648.9	155.7	0.1	37.0	192.7	0.041%
42	LS-3	78,977.1	1,890.8	7.3	3,414.8	5,312.9	0.137%	9,106.2	208.9	0.8	204.1	413.9	0.203%
43	DWL	2,395.5	407.5	0.1	103.6	511.2	0.022%	15.7	2.9	0.0	0.4	3.3	0.023%
44	OL-1	13,383.7	1,558.2	0.6	578.7	2,137.5	0.030%	77.9	7.3	0.0	1.7	9.1	0.041%
45		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
46	Group Total	627,312.5	59,510.8	33.6	27,123.7	86,668.1	0.039%	15,297.4	521.5	1.1	342.8	865.5	0.131%
47													
48													
49	Total 5 Cust Gps.	71,603,580.9	3,834,025.3	19,748.2	5,203,177.3	9,056,950.8	0.219%	11,551,540.0	341,189.2	1,838.1	258,289.7	601,317.1	0.307%
50		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
51	CPUC Juris. Other												
52													
53	Spec. Con. Sub.	808,414.0	6,160.1	5.4	54,163.7	60,329.3	0.009%	0.0	0.0	0.0	0.0	0.0	0.000%
54		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
55	Group Total	808,414.0	6,160.1	5.4	54,163.7	60,329.3	0.009%	0.0	0.0	0.0	0.0	0.0	0.000%
56													
57		---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------	---------------
58	Grand Total	72,411,994.9	3,840,185.4	19,753.6	5,257,341.1	9,117,280.1	0.217%	11,551,540.0	341,189.2	1,838.1	258,289.7	601,317.1	0.307%
				$\boxed{21,591.8}$									

Scaling distribution rates for the entire Domestic rate group would result in violation of rate level restrictions imposed by AB1X, because increases in the distribution component would result in an overall increase in total rates for usage up to 130 percent of baseline allowances. In order to avoid this result, SCE proposes to maintain current monthly customer charges and to reduce the SCE Generation component of Tier 1 and 2 energy charges to offset increases in the distribution component. Based on the most recently authorized sales forecast for the Domestic rate group, SCE then determines the resulting generation revenue under-collection. The SCE Generation component of Tier 3 and 4 energy charges are then adjusted upward (by an equal percentage) to offset the revenue under-collection. This methodology for domestic tiered rate design in the presence of AB1X restrictions was first proposed by SCE in Advice 1808-E, in implementing Commission authorized revenue requirements in Phase 1 of the 2003 GRC. The Commission subsequently approved SCE's methodology on an interim basis and ordered SCE to file an application to formally propose this rate design methodology. SCE filed its application for approval of its generic proposal for allocating AB1X generation revenue shortfalls on March 28, 2005.

Scaling distribution rate components on a SAPC basis results in rate group average impacts which vary between classes, based on the ratio of class distribution revenue to the total revenue requirement. In addition, the rate adjustments necessitated by AB1X restrictions result in a disproportionate impact of revenue increases on domestic customers served in the higher usage tiers. Nearly 40 percent of domestic service customers are insulated from bill impacts, because Tier 1 and Tier 2 energy charges are not increased. Table K-8 includes illustrative percentage monthly bill impacts for domestic service customers by usage level. As discussed above, the highest absolute and percentage impacts are expected to occur for customers with the largest portion of their total consumption in the upper tiers while customers whose usage is concentrated in the lower tiers enjoy the protection offered by AB1X.

Table K-8
2005 Revenue Requirement-Settlement (Adjusted for 2005 ERRA and DWR)
Estimates of Sales and Proposed Rate Revenue

		Scenario 17											
Line No.	Rate Schedule By Customer Group	Bundled MWh (M)	Bundled Delivery ($M)	Net AMI Rev Req ($M)	Bundled Generation ($M)	Bundled Total ($M)	Bundled Impact	DA MWh (M)	DA Delivery ($M)	Net AMI Rev Req ($M)	DA Generation ($M)	DA Total ($M)	DA Impact
1	Domestic												
2	D	20,135,434.6	0.07207	0.00036	0.06866	0.14110	0.258%	169,869.8	0.07026	0.00036	0.02241	0.09303	0.391%
3	D-CARE	4,768,928.4	0.03238	0.00036	0.06130	0.09405	0.390%	25,889.3	0.02991	0.00036	0.00000	0.03028	1.220%
4	D-APS	1,003,886.0	0.05417	0.00033	0.07485	0.12934	0.256%	17,007.9	0.05568	0.00033	0.02241	0.07842	0.423%
5	DE	98,588.6	0.03570	0.00010	0.07009	0.10590	0.093%	40.9	0.04642	0.00010	0.02241	0.06893	0.143%
6	DM	128,705.6	0.07138	0.00036	0.06800	0.13974	0.256%	4,411.8	0.06977	0.00036	0.02241	0.09254	0.388%
7	DMS-1	33,007.4	0.07241	0.00037	0.06592	0.13870	0.264%	305.1	0.06975	0.00037	0.02241	0.09252	0.396%
8	DMS-2	450,209.4	0.05905	0.00034	0.07052	0.12991	0.265%	10,875.4	0.05892	0.00034	0.02241	0.08167	0.422%
9													
10	Group Total	26,618,760.1	0.06393	0.00036	0.06761	0.13190	0.274%	228,400.1	0.06404	0.00036	0.01987	0.08427	0.428%
11													
12	Lighting-SM Med Power												
13	GS-1	4,711,671.5	0.06470	0.00030	0.08649	0.15149	0.196%	68,342.3	0.06419	0.00030	0.02241	0.08689	0.342%
14	GS-2	20,815,376.6	0.05390	0.00027	0.08373	0.13790	0.194%	3,195,515.9	0.03967	0.00027	0.02241	0.06234	0.430%
15	GS-2-S	0.0						0.0					
16	TC-1	83,701.5	0.04529	0.00024	0.06493	0.11046	0.216%	1,428.5	0.04984	0.00024	0.02241	0.07249	0.329%
17	TOU-GS-2	698,972.9	0.03606	0.00016	0.06188	0.09811	0.166%	90,170.7	0.03132	0.00016	0.02241	0.05389	0.303%
18													
19	Group Total	26,309,722.6	0.05537	0.00027	0.08359	0.13923	0.194%	3,355,457.4	0.03995	0.00027	0.02241	0.06262	0.425%
20													
21	Large Power												
22	TOU-8-SEC	7,350,487.5	0.04055	0.00020	0.07166	0.11240	0.180%	2,033,165.9	0.03821	0.00020	0.02241	0.06082	0.333%
23	TOU-8-PRI	4,793,763.8	0.03410	0.00016	0.06760	0.10186	0.162%	1,675,413.6	0.03143	0.00016	0.02241	0.05401	0.306%
24	TOU-8-SUB	3,011,507.2	0.01025	0.00004	0.05817	0.06846	0.057%	4,155,215.8	0.01408	0.00004	0.02241	0.03653	0.107%
25	TOU-8-S-SEC	0.0						0.0					
26	TOU-8-S-PRI	0.0						0.0					
27	TOU-8-S-SUB	0.0						0.0					
28													
29	Group Total	15,155,758.4	0.03316	0.00016	0.06792	0.10124	0.160%	7,863,795.3	0.02401	0.00011	0.02241	0.04653	0.233%
30													
31	Agricultural & Pumping												
32	PA-1	414,290.5	0.05912	0.00033	0.09095	0.15040	0.220%	3,687.6	0.04107	0.00033	0.02241	0.06381	0.520%
33	PA-2	351,018.8	0.03939	0.00020	0.06834	0.10794	0.188%	8,830.7	0.03211	0.00020	0.02241	0.05472	0.372%
34	TOU-AG	1,192,100.3	0.03811	0.00018	0.03854	0.07683	0.241%	69,156.9	0.03621	0.00018	0.02241	0.05880	0.315%
35	TOU-PA-5	934,617.8	0.03201	0.00015	0.04295	0.07510	0.197%	6,914.7	0.03295	0.00015	0.02241	0.05550	0.267%
36													
37	Group Total	2,892,027.4	0.03930	0.00020	0.05109	0.09059	0.217%	88,589.8	0.03575	0.00019	0.02241	0.05835	0.326%
38													
39	Street & Area Lighting												
40	LS-1	434,868.8	0.11838	0.00005	0.04324	0.16166	0.030%	4,448.7	0.03297	0.00005	0.02241	0.05543	0.087%
41	LS-2	97,687.3	0.04274	0.00005	0.04324	0.08603	0.056%	1,648.9	0.09441	0.00005	0.02241	0.11687	0.041%
42	LS-3	78,977.1	0.02394	0.00009	0.04324	0.06727	0.137%	9,106.2	0.02295	0.00009	0.02241	0.04545	0.203%
43	DWL	2,395.5	0.17010	0.00005	0.04324	0.21339	0.022%	15.7	0.18660	0.00005	0.02241	0.20906	0.023%
44	OL-1	13,383.7	0.11642	0.00005	0.04324	0.15971	0.030%	77.9	0.09380	0.00005	0.02241	0.11626	0.041%
45													
46	Group Total	627,312.5	0.09487	0.00005	0.04324	0.13816	0.039%	15,297.4	0.03409	0.00007	0.02241	0.05658	0.131%
47													
48													
49	Total 5 Cust Gps.	71,603,580.9	0.05355	0.00028	0.07267	0.12649	0.219%	11,551,540.0	0.02954	0.00016	0.02236	0.05206	0.307%
50													
51	CPUC Juris. Other												
52													
53	Spec. Con. Sub.	808,414.0	0.00762	0.00001	0.06700	0.07463	0.009%	0.0					
54													
55	Group Total	808,414.0	0.00762	0.00001	0.06700	0.07463	0.009%	0.0					
56													
57													
58	Grand Total	72,411,994.9	0.05303	0.00027	0.07260	0.12591	0.217%	11,551,540.0	0.02954	0.00016	0.02236	0.05206	0.307%