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SOUTHERN CALIFORNIA EDISON

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

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

Before the

Public Utilities Commission of the State of California

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I.

INTRODUCTION

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

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

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

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

II.

CURRENT TECHNOLOGY AND MARKET ASSESSMENT

A. Technology Overview

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

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

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

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

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

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

B. Technology Assessment

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

(1) Support dynamic tariffs;

(2) Provide customers with access to usage data;

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

(4) Compatible with applications that utilize collected data;

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

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

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

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

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

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

1. Current Market Dynamics and Opportunities

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

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

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

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

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

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

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

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

2. State of Today's Current Meter Marketplace

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

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

Figure 2-1
Sample Vendors in AMI Market Segments

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

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

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

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

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

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

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

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

C. Overcoming Market Challenges

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

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

1. Overview of Enel's Experience

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

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

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

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

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

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

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

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

Figure 2-2
Benefits of Enel AMI Solution

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

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

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

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

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

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

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

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

2. Additional Functionality Not Offered in a Comprehensive Solution

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

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

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

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

3. SCE Metering Development Experience

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

III.

PROPOSED DEPLOYMENT STRATEGY

A. Overview

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

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

B. Approach

1. Design Objective

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

a) New Meters Should Provide Multiple Operational Benefits

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

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

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

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

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

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

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

c) New Meters Should be Adaptable

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

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

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

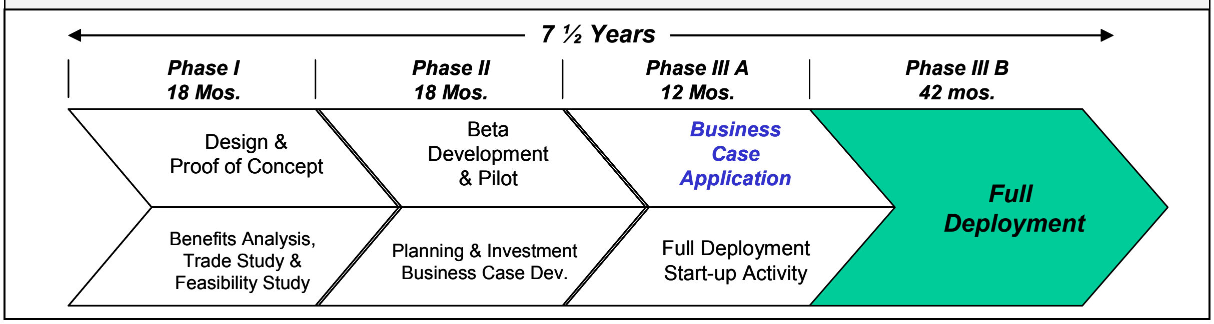
d) Achieving the Design Objectives

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

2. Meter Development Method

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

Figure 2-3
AIM Meter Product Development Process



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

Phase I - Design and Proof of Concept;

Phase II - Beta Development and Pilot; and

Phase III - Commercialization and Full Deployment.

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

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

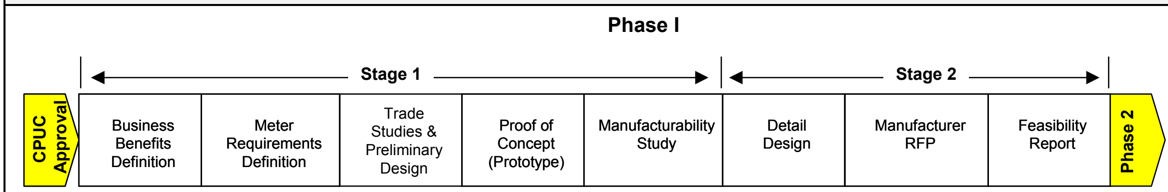
At the end of Phase II, we intend to file an application with the Commission seeking authority for full deployment AIM product if the final business case analysis demonstrates that it is beneficial for our customers to proceed with such deployment. This future application will incorporate the information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

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

3. Phase I: Concept Development

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

Figure 2-4
Phase I Summary Schedule



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

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

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

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

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

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

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

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

a) Beta Meter Development and Field Testing

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

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

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

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

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

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

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

b) Business Case and Preliminary Activity

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

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

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

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

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

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

5. Product Development Organization

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

a) Product-Development Team

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

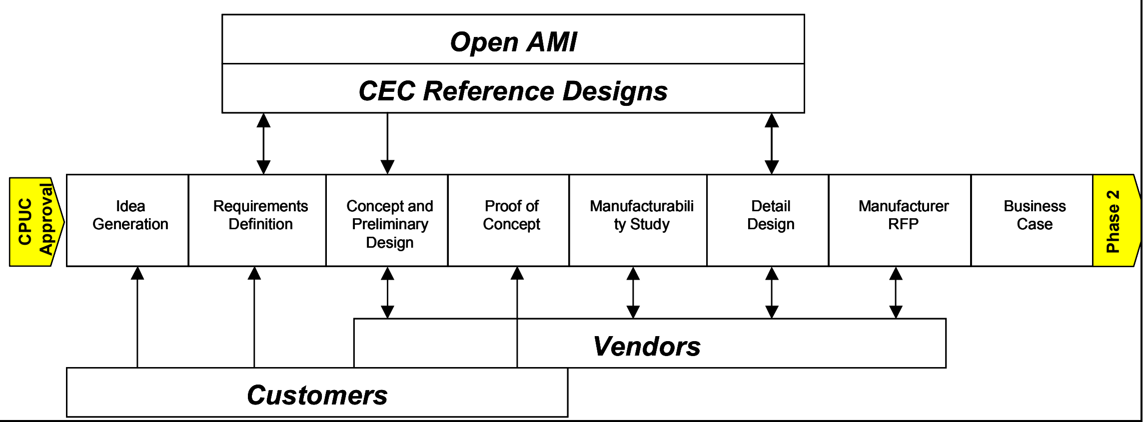
We intend to engage a consulting Chief Systems Engineer to represent our interest, from a technical perspective, in the product development effort by working with the selected engineering design firm, vendors and other stakeholders. Additionally, the Chief Systems Engineer will facilitate the process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

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

b) Vendors and Stakeholders

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

Figure 2-5
Conceptual Stakeholder Collaboration Model



6. Budget for Phases I and II

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

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

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

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

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

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

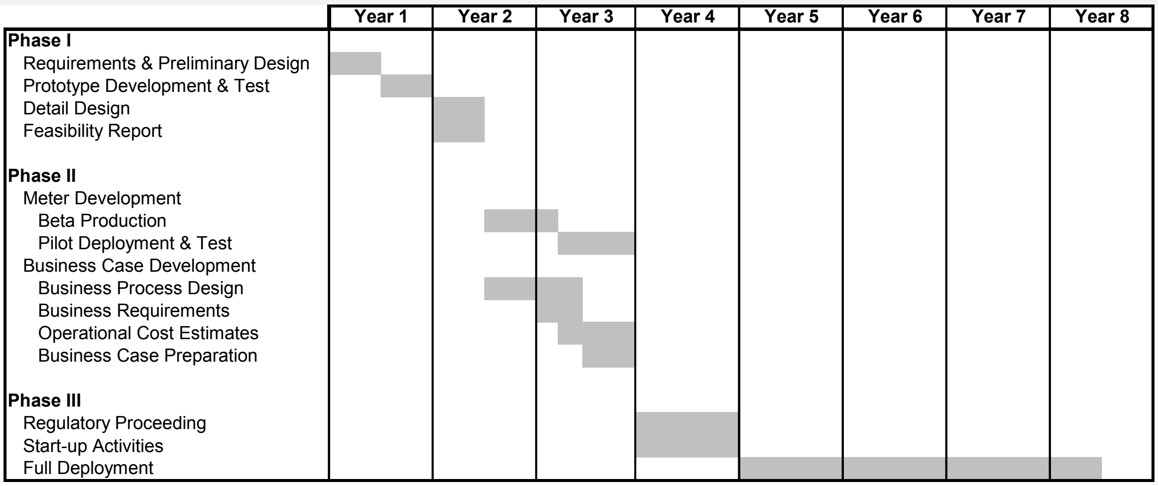
	Year 1	Year 2	Year 3	Total
Phase I Estimated Costs	**$8.0**	**$4.0**	**$0.0**	**$12.0**
Phase II Estimated Costs	**$0.0**	**$10.5**	**$8.5**	**$19.0**
Total Estimated Costs	***$8.0***	***$14.5***	***$8.5***	***$31.0***

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

7. Timeline

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

Figure 2-6
AIM Meter Product Development and Process Timeline



C. Feasibility

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

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

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

IV.

COST RECOVERY PROPOSAL

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

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

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

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

B. Proposed Operation of the AIMBA

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

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

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

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

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

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

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

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